Safety Evaluation Report

Related to the License Renewal of South Texas Project, Units 1 and 2

Docket Nos. 50-498 and 50-499

South Texas Project Nuclear Operating Company

United States Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

June 2017

ABSTRACT

This safety evaluation report (SER) documents the technical review of the South Texas Project (STP), Units 1 and 2, license renewal application (LRA) by the U.S. Nuclear Regulatory Commission (NRC) staff (the staff). By letter dated October 25, 2010, South Texas Nuclear Operating Company (STPNOC or the applicant) submitted the LRA in accordance with Title 10, Part 54, of the *Code of Federal Regulations*, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants" (10 CFR Part 54). The applicant requests renewal of the STP operating licenses (Facility Operating License Numbers DPR-76 and DPR-80, respectively) for a period of 20 years beyond the current license periods ending August 20, 2027 (Unit 1), and December 15, 2028 (Unit 2).

STP is located near the town of Matagorda, Texas, in Matagorda County, Texas. The staff issued the original construction permits for STP on December 22, 1975 (both units), and the operating licenses on August 20, 1987 (Unit 1), and December 15, 1988 (Unit 2). Each unit's nuclear steam supply system consists of a 4-loop pressurized-water reactor (PWR) designed by Westinghouse Electric Corporation. The primary containment for each unit is a dry ambient design. The balance of plant was designed and constructed by Bechtel Corporation. Both units operate at a licensed power output of 3,853 MWt, with a net electrical power output of 1,250 MWe each. The updated final safety analysis report contains details of the plant and the site.

Unless otherwise indicated, this SER presents the status of the staff's review of information submitted through May 2, 2017, the cutoff date for consideration in this SER. The open item previously identified in the SER with Open Items, issued October 2016, has been closed (see Section 1.5); therefore, no open items remain to be resolved before the final determination is reached by the staff on the LRA.

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ABBREVIATIONS

AAC	all aluminum conductors
ACAR	aluminum conductor alloy reinforced
ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards
ACSR	aluminum core, steel reinforced
ACT	analysis confirmatory test
ADAMS	Agencywide Documents Access and Management System
AEA	Atomic Energy Act
AERM	aging effect requiring management
AFST	auxiliary feedwater storage tank
AFW	auxiliary feedwater
AHU	air handling unit
AISC	American Institute of Steel Construction
A/LAI	applicant/licensee action item
AMP	aging management program
AMR	aging management review
ANS	American Nuclear Society
ANSI	American National Standards Institute
APCSB	Auxiliary and Power Conversion Systems Branch
ART	adjusted reference temperature
ASM	American Society for Metals
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATWS	anticipated transient without scram
AVB	anti-vibration bar
AWAA	American Water Works Association
BMI	bottom-mounted instrumentation
BOP	balance of plant
BTP	Branch Technical Position
BWR	boiling-water reactor
C	Celsius
CAP	Corrective Action Program
CASS	cast austenitic stainless steel
CBF	cycle-based fatigue
CCCW	closed-cycle cooling water
CCW	component cooling water
CE	Combustion Engineering
CEA	control element assembly
CEO	Chief Executive Officer
CEOG	Combustion Engineering Owners Group
CETNA	core exit thermocouple nozzle assembly
CFO	Chief Financial Officer
CFR	*Code of Federal Regulations*
CLB	current licensing basis
cm^2	square centimeter
CMAA	Crane Manufacturers Association of America

CMTR	certified material test report
CMU	concrete masonry unit
COMS	cold overpressure mitigation system
CR	condition report
CRD	control rod drive
CRDM	control rod drive mechanism
CRGT	control rod guide tube
CUF	cumulative usage factor
CUF_{en}	environmentally correct cumulative usage factor
CVCS	chemical and volume control system
DBA	design basis accident
DBE	design basis event
DGB	diesel generator building
DPI	digital pressure indicator
E	energy
EAB	electrical auxiliary building
EAF	environmentally-assisted fatigue
ECCS	emergency core cooling system
ECP	essential cooling pond
	essential cooling water pond
ECW	essential cooling water
ECWIS	essential cooling water intake structure
ECWS	essential cooling water system
EFPY	effective full power year
EOL	end of life
EPDM	ethylene-propylene-diene
EPRI	Electric Power Research Institute
EQ	environmental qualification
ERFDADS	Emergency Response Facilities Data Acquisition and Display System
ESF	engineered safety feature
EW	essential cooling water
F	Fahrenheit
F_{en}	environmental adjustment factor
FERC	Federal Energy Regulatory Commission
FHAR	fire hazards analysis report
FHB	fuel handling building
FOCD	foreign ownership, control, or domination
FOCI	foreign ownership, control, or influence
FRN	*Federal Register Notice*
FSAR	final safety analysis report
ft	foot
ft-lb	foot-pound (energy)
FTIR	Fourier transform infrared
FWIV	feedwater isolation valve
FWST	firewater storage tank
GALL	Generic Aging Lessons Learned (NUREG-1801)
GDC	general design criterion

GEIS	generic environmental impact statement
GL	generic letter
gpm	gallons per minute
HAZ	heat-affected zone
HELB	high-energy line break
HPSI	high-pressure safety injection
HVAC	heating, ventilation, and air conditioning
I&C	instrumentation and control
I&E	inspection and flaw evaluation
IASCC	irradiation-assisted stress corrosion cracking
IEEE	Institute of Electrical and Electronics Engineers
IGSCC	intergranular stress corrosion cracking
ILRT	integrated leak rate testing
IN	Information Notice
in^2	square inch
INPO	Institute for Nuclear Power Operations
IPA	integrated plant assessment
IR	insulation resistance
ISA	International Society of Automation
ISG	interim staff guidance
ISI	inservice inspection
ISIT	initial structural integrity test
ksi	kilopounds per square inch
kV	kilovolt
lb	pound
LBB	leak-before-break
LCO	limiting condition for operation
LER	licensee event report
LOCA	loss-of-coolant accident
LRA	license renewal application
LR-ISG	License Renewal Interim Staff Guidance
LSS	low safety significance
LTOP	low temperature overpressure protection
LTW	long-term weighting
LWR	light-water reactor
M	margin term
MAB	mechanical auxiliary building
MDPE	medium-density polyethylene
MEAB	mechanical-electrical auxiliary building
MEB	metal-enclosed bus
MED	master equipment database
MeV	million electron volts
MIC	microbiologically-influenced corrosion
MRP	Materials Reliability Program
MRV	minimum required value
MSIV	main steam isolation valve

MWe	megawatt(s) electric
MWt	megawatt(s) thermal
n	neutron
NACE	National Association of Corrosion Engineers
NEI	Nuclear Energy Institute
NFPA	National Fire Protection Agency
Ni	nickel
NOC	Nuclear Operations Committee
NPS	nominal pipe size
NRC	U.S. Nuclear Regulatory Commission
NRG	NRG Energy, Inc.
NRS	non-risk significant
NSSS	nuclear steam supply system
OBE	operating-basis earthquake
OD	outside diameter
ODSCC	outside diameter stress-corrosion cracking
OEP	Operating Experience Program
OI	open item
OOS	out of specification
OTSG	once-through steam generator
PDI	performance demonstration initiative
PDMS	plant data management system
PE	profile examination
PMWO	preventive maintenance work order
PORV	power operated relief valve
ppm	parts per million
PRT	pressurizer relief tank
psig	pounds per square inch gauge
P-T	pressure-temperature
PTS	pressurized thermal shock
PUCT	Public Utilities Commission of Texas
PVC	polyvinyl-chloride
PWR	pressurized-water reactor
PWSCC	primary water stress corrosion cracking
QA	quality assurance
RAI	request for additional information
RCB	reactor containment building
RCCA	rod control cluster assembly
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RCSC	Research Council on Structural Connections
RFO	refueling outage
RG	regulatory guide
RHR	residual heat removal
RIS	Regulatory Issue Summary

RP	Regulatory Position
RPV	reactor pressure vessel
RRVCH	replacement reactor vessel closure head
RSG	replacement steam generator
RT_{NDT}	reference temperature (nil ductility)
$RT_{NDT(U)}$	reference temperature (nil ductility) - unirradiated
RT_{PTS}	reference temperature (pressurized thermal shock)
RV	reactor vessel
RVI	reactor vessel internal
RVIIP	reactor vessel internals inspection plan
RVWLIS	RV water level indicator system
RWST	refueling water storage tank
S_a	allowable stress value
SBO	station blackout
SC	structure and component
SCC	stress corrosion cracking
SDG	standby diesel generator
SE	safety evaluation
SEC	Securities and Exchange Commission
SECY	Secretary of the Commission, Office of the Nuclear Regulatory Commission
SER	safety evaluation report
SG	steam generator
SI	spatial interaction
SIT	structural integrity test
S_m	design stress intensity
SRP-LR	standard review plan-license renewal (NUREG-1800)
SSC	structures, systems, and components
SSER	Supplemental Safety Evaluation Report
SSPC	Steel Structures Painting Council
STP	South Texas Project
STPNOC	South Texas Project Nuclear Operating Company
STW	short-term weighting
SWOL	structural weld overlay
TE	thermal embrittlement
TGB	turbine generator building
TLAA	time-limited aging analysis
TOFD	time-of-flight-diffraction
TS	technical specifications
TSC	technical service center
TSP	trisodium phosphate
UFSAR	updated final safety analysis report
USAR	updated safety analysis report
U.S.C.	U.S. Code
USE	upper-shelf energy
UT	ultrasonic testing
V	volt

WCAP	Westinghouse Commercial Atomic Power
wt-%	weight percent
XL	extra-long
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 South Texas Project (STP), Units 1 and 2, as filed by STP Nuclear Operating Company (STPNOC or the applicant). By letter dated October 25, 2010, STPNOC submitted its application to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the STP, Units 1 and 2, operating licenses 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 Rule). The NRC license renewal project manager for this review is Lois M. James. Ms. James can be contacted by telephone at 301-415-3306 or by email at Lois.James@nrc.gov. Alternatively, written correspondence may be sent to the following address:

U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Division of License Renewal
Washington, DC 20555-0001
Attention: Lois M. James, Mail Stop O11-F1

In its October 25, 2010, submission letter, the applicant requested renewal of the operating licenses issued under Section 104b (Operating License Nos. NPF-76 and NPF-80) of the Atomic Energy Act of 1954 (AEA), as amended, for STP, Units 1 and 2, respectively, for a period of 20 years beyond the current license periods ending August 20, 2027 (Unit 1), and December 15, 2028 (Unit 2). STP is located near the town of Matagorda, Texas, in Matagorda County, Texas. The staff issued the original construction permits for STP on December 22, 1975 (both units), and the operating licenses on August 20, 1987 (Unit 1), and December 15, 1988 (Unit 2). Each unit's nuclear steam supply system consists of a 4-loop pressurized-water reactor (PWR) designed by Westinghouse Electric Corporation. The primary containment for each unit is a dry ambient design. The balance of plant was designed and constructed by Bechtel Corporation. Both units operate at a licensed power output of 3,853 MWt, with a net electrical output of 1,250 MWe each. 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 safety review and an environmental review. The NRC regulations in 10 CFR Part 54 and in 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 STP license renewal is based on the applicant's LRA and on its responses to the staff's requests for additional information (RAIs). The applicant supplemented the LRA and provided clarifications through its responses to the staff's RAIs in audits, meetings, and docketed correspondence. Unless otherwise noted, the staff reviewed and considered information submitted through May 2, 2017. The staff may consider information received after that date depending on the progress 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, Maryland, 20852-2738 (301-415-4737/800-397-4209). The LRA may also be viewed at the Bay City Public Library, 1100 7th Street, Bay City, Texas 77414. In addition, the public may find the LRA, as well as materials related to the license renewal review, on the NRC website 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 units' proposed operation for an additional 20 years beyond the respective terms of the current operating licenses. The staff reviewed the LRA in accordance with NRC regulations and the guidance in NUREG-1800, Revision 2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR), dated December 2010.

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 that lists 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 prepared a plant-specific supplement to NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS)." ("Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Supplement 48 Regarding South Texas Project, Units 1 and 2," published November 2013). This supplement discusses the environmental considerations for the license renewal of STP, Units 1 and 2.

1.2 License Renewal Background

Pursuant to the AEA, 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 based on an expected 40-year service life.

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

In 1991, the staff published 10 CFR Part 54, the License Renewal Rule (Volume 56, page 64943, of the *Federal Register* (56 FR 64943), dated December 13, 1991). The staff participated in an industry-sponsored demonstration program to apply 10 CFR Part 54 to a pilot plant and to gain the experience necessary to develop implementation guidance. To establish a scope of review for license renewal, 10 CFR Part 54 defined age-related degradation unique to license renewal. However, during the demonstration program, the staff found that adverse aging effects on plant systems and components are managed during the period of initial license, and that the scope of the review did not allow sufficient credit for management programs, particularly the implementation of 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” which regulates management of plant-aging phenomena. As a result of this finding, the staff amended 10 CFR Part 54 in 1995. The amended 10 CFR Part 54, as published on May 8, 1995, in 60 FR 22461, establishes a regulatory process that is simpler and more predictable than the previous version of 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 Commission changed the rule 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 Commission 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 (NEPA).

1.2.1 Safety Review

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

(1) The regulatory process is adequate to ensure that the licensing bases of all currently operating plants maintain an acceptable level of safety, with the possible exception of the detrimental aging effects on the function of certain SSCs as well as a few other safety-related issues, during the period of extended operation.

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

In implementing these two principles, 10 CFR 54.4, “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) that are relied on to demonstrate compliance with NRC regulations for fire protection, environmental qualification (EQ), pressurized thermal shock (PTS), anticipated transient without scram (ATWS), and station blackout (SBO).

Pursuant to 10 CFR 54.21(a), an applicant for a renewed license 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 a change in configuration or properties (i.e., are “passive”) and are not subject to replacement based on a qualified life or specified time period (i.e., are “long-lived”). As required by 10 CFR 54.21(a), an applicant for a renewed license must demonstrate that the aging effects will be managed so that the intended functions of those SSCs will be maintained consistent with the current licensing basis (CLB) for the period of extended operation; however, active equipment is considered adequately monitored and maintained by existing programs. In other words, the applicant must show that 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.

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

License renewal requires identification and updating of time-limited aging analyses (TLAAs). 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 effects of aging on these SSCs can be adequately managed for the period of extended operation.

In 2005, the staff issued Regulatory Guide (RG) 1.188, Revision 1, "Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses." This RG endorses Nuclear Energy Institute (NEI) 95-10, Revision 6, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54—The License Renewal Rule," issued in June 2005 by NEI. NEI 95-10 details an acceptable method of implementing 10 CFR Part 54. The staff also used the SRP-LR to review this application.

In its LRA, the applicant stated that it used the process described in NEI 95-10, Revision 6 (issued June 2005), NUREG-1800, Revision 1, "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants," dated September 2005, and NUREG-1801, "Generic Aging Lessons Learned (GALL) Report" (Revision 1, dated September 2005). The GALL Report summarizes staff-approved aging management programs (AMPs) for many SCs subject to an AMR. An applicant's willingness to commit to carrying out these staff-approved AMPs could potentially reduce the time, effort, and resources in reviewing an applicant's LRA and, thereby, improve the efficiency and effectiveness of the license renewal review process. The report is also a reference for both applicants and the staff to use to identify AMPs and activities that can provide adequate aging management during the period of extended operation. It is incumbent on the applicant to ensure that the conditions and operating experience at the plant are bounded by the conditions and operating experience for which the GALL Report was evaluated. If these bounding conditions are not met, the applicant should address the additional effects of aging and augment its AMP as appropriate.

During the applicant's preparation and submittal of its LRA, the staff was in the process of developing and implementing Revision 2 to the SRP-LR and to the GALL Report. Revisions to these two documents were issued in December 2010. As described above, the applicant's LRA was developed to Revision 1 of both the SRP-LR and the GALL Report. The staff performed its reviews in accordance with the requirements of 10 CFR Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," and the guidance provided in SRP-LR, Revision 2, and the GALL Report, Revision 2, both dated December 2010. While this SER is formatted to align with the LRA, using the numbering sequences of the SRP-LR and the GALL Report, Revision 1, the staff reviewed LRA content using the guidance in Revision 2 of the SRP-LR and the GALL Report. In places where LRA information differed from Revision 2 of the SRP-LR and the GALL Report, the staff issued RAIs to obtain information to complete its evaluation.

1.2.2 Environmental Review

Part 51 of 10 CFR contains environmental protection regulations. In December 1996, the staff revised the environmental protection regulations to facilitate the environmental review for license renewal. The staff prepared a "Generic Environmental Impact Statement (GEIS) for License Renewal of Nuclear Plants" (NUREG-1437) to document its evaluation of the possible environmental impacts associated with renewing licenses of nuclear power plants. For certain types of environmental impacts, the GEIS establishes generic findings applicable 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. In accordance with 10 CFR 51.53(c)(3)(i), an applicant for license renewal may incorporate these generic findings in its environmental report. In accordance with 10 CFR 51.53(c)(3)(ii), an environmental report must also include analyses of environmental impacts that must be evaluated on a plant-specific basis (i.e., Category 2 issues).

In June 2013 (78 FR 37282), the NRC staff issued a final rule revising 10 CFR Part 51 to redefine the number and scope of environmental impact issues that must be addressed during license renewal environmental reviews and to update the potential environmental impacts associated with the renewal of an operating license for a nuclear power reactor for an additional 20 years. Revision 1 to the GEIS was issued concurrently with the final rule (78 FR 37325). The revised GEIS specifically supports the revised list of environmental issues identified in the final rule. Revision 1 to the GEIS and the 2013 final rule reflect lessons learned and knowledge gained during previous license renewal environmental reviews.

In accordance with NEPA and the requirements of 10 CFR Part 51, the staff reviewed the plant-specific environmental impacts of license renewal, including whether there was any new and significant information not considered in the GEIS. As part of its scoping process, the staff held two public meetings on March 2, 2011, in Bay City, Texas, to identify plant-specific environmental issues. The final, plant-specific GEIS Supplement 48 documents the results of the environmental review and contains the NRC staff's final recommendation on the license renewal action.

1.3 <u>Principal Review Matters</u>

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

Foreign Ownership, Control, or Domination

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. During its review of Section 1, the staff identified an area involving foreign ownership, control, or domination (FOCD) in which additional information would be necessary to complete its evaluation. In addressing FOCD, the staff considered guidance in the Standard Review Plan (SRP), "Foreign Ownership, Control, and Domination of Applicants for Reactor Licenses, "dated June 1999 (SRP on FOCD), to determine whether the applicant was owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government. The NRC published the SRP on FOCD in the *Federal Register* on September 28, 1999 (64 FR 52357-52359). Additionally, the staff considered the

FOCD statute under the Section 103.d of the AEA, considered the FOCD statute under the 10 CFR 50.38 and 10 CFR 54.17(b) for LRAs. These requirements, in relevant part, state that "[a]ny person who is a citizen, national, or agent of a foreign country, or any corporation, or other entity which the Commission knows or has reason to believe is owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government, shall be [are] ineligible to apply for and obtain a [renewed] license."

During its initial review, the staff noted that LRA Section 1.1.4 identified the following salient points related to FOCD:

- Mr. Mauricio Gutierrez, a non-U.S. citizen of Mexico, was the Executive Vice President and Chief Operating Officer of NRG Energy, Inc. (NRG), and the Vice President of Texas Genco GP, LLC.
- NRG was the ultimate parent corporation and owner of subsidiaries Texas Genco GP, LLC, NRG South Texas, LP, and STPNOC.
- NRG South Texas, LP, and STPNOC were listed among the "applicant and co-owners" for STP, Units 1 and 2.
- Texas Genco GP, LLC, was "the sole general partner of NRG South Texas LP… [which] holds the actual interest in the South Texas Project."
- The officers and managers of Texas Genco GP, LLC, act for NRG South Texas LP.

Based on this information, it was not clear to the staff whether the applicant could fully meet the requirements regarding FOCD as it pertains to activities authorized by the renewed license.

Prior to acceptance of the LRA for docketing, by letter dated December 10, 2010, the staff issued RAI 1.1.4-1, requesting that the applicant describe how STPNOC planned to mitigate foreign control or domination, including, but not limited to, matters relating to nuclear safety and security, and responsibility for special nuclear material. The staff requested that the applicant also provide the following:

- a list of any non-U.S. citizens who are members of its boards
- an explanation of whether any foreign person has power (whether direct or indirect) to control election, appointment, or tenure of STPNOC's governing board
- an explanation of whether any foreign person has power to control or cause direction of any decisions by STPNOC's board or by management positions responsible for NRC-licensed activities
- an explanation of whether STPNOC has any contracts, agreements, or arrangements with a foreign person or persons
- an explanation of whether any unanimous consent issues could include a foreign entity who would have effective veto power over the consent issue or any pertinent operational issues, thus giving the foreign person or entity direct or indirect control

In its response dated December 21, 2010, the applicant stated, in part, that STPNOC is a Texas non-profit corporation that has no members other than its Board of Directors, which manages all of its affairs. The applicant also stated that the three co-owners of STP, Units 1 and 2 (the City of Austin, CPS Energy, and NRG South Texas, LP)—for whom STPNOC is authorized to act—each select a director for STPNOC. The three directors elect the fourth director of STPNOC, who then also serves as its Chief Executive Officer (CEO). In addition, the City of Austin and CPS Energy are governmental organizations in the State of Texas that are controlled by city councils elected by the citizens of these U.S. cities. The applicant further stated that all of the STPNOC directors are U.S. citizens appointed by organizations that are under U.S. control. While the three co-owners of STP, Units 1 and 2, have rights and decision-making authority regarding financial and other matters pursuant to the terms of their participation agreements, STPNOC is not owned by them. Finally, the applicant stated that STPNOC is the applicant with sole responsibility with respect to activities licensed by the NRC. Specifically:

> STPNOC is the licensee responsible for operation pursuant to the STP [Units] 1&2 licenses. As such, throughout the operation of STP [Units] 1&2, STPNOC has and will have sole responsibility with respect to matters involving nuclear safety, quality, security or reliability, including responsibility for special nuclear material and compliance with all NRC nuclear safety and security requirements (STPNOC's "Sole Authority").

The applicant also stated that only one non-U.S. citizen served on a board—Mr. Gutierrez, who serves as Executive Vice President and Chief Operating Officer of NRG. As the Executive Vice President and Chief Operating Officer, Mr. Gutierrez oversees NRG's Plant Operations, Commercial Operations, Environmental Compliance, as well as the Engineering, Procurement and Construction divisions, which do not include any responsibility for STP, Units 1 and 2. Additionally, on January 27, 2016, in accordance with 10 CFR 95.17(a)(1), STPNOC submitted information which documents the current status of Foreign Ownership, Control, or Influence (FOCI) for STPNOC. Specifically, STPNOC provided a "Certificate Pertaining to Foreign Interests," as well as an enclosure titled "Supplemental Information for Certificate Pertaining to Foreign Interests." With this information, the applicant informed the NRC that Mr. Gutierrez holds the position of Executive Vice President and CEO and is a citizen of Mexico and a citizen of the United States. During subsequent open-source analysis, the staff found that Mr. Gutierrez is currently the President and CEO of NRG. However, now that he is a citizen of the United States, regardless of his dual-citizenship status, there are no longer concerns with respect to foreign ownership, control, or domination (FOCD) and the citizenship of Mr. Gutierrez.[1]

Furthermore, the applicant stated that no foreign person or entity has power of control over, nor can cause direction of, any decisions related to activities licensed by the NRC. The applicant also stated in its response that there were no contracts or agreements with foreign entities that would give that entity any control over STPNOC or its decisions on NRC licensed activities, and there were no unanimous consent issues, "which would potentially include foreign board members, quorum provisions, or other operational issues which may be subject to foreign control, either indirect or direct."

Subsequent to acceptance of the LRA for docketing, the staff noted that NRG had multiple joint ventures and agreements with foreign entities, including a joint venture with Toshiba Power

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[1] AEA §§ 103 and 104 use the terms "alien" and "foreign." These terms are not defined in the AEA. However, elsewhere in U.S. law, "alien" is defined as any person that is not a citizen or national of the United States. *See* Immigration and Nationality Act, 8 U.S.C. § 1101. Additionally, Supreme Court practice uses the terms "alien" and "foreign citizen" interchangeably to refer to individuals who are not citizens of the United States. *See Bluman v. FEC*, 800 F.Supp.2d 281, 283 n.1 (D.D.C., 2011). Taken together, a dual citizen of a foreign country and the United States is not an "alien" because he/she is a citizen of the United States, *see id.*, and, thus, is not subject to the FOCD prohibition of AEA §§ 103 and 104. However, dual citizenship could be taken into consideration as part of the AEA §§ 103 and 104 "inimicality" determination.

Systems named Nuclear Innovations North America to develop nuclear power projects in North America based on Toshiba's advanced boiling-water reactor design. The staff also reviewed Securities and Exchange Commission (SEC) filings for NRG. The Securities and Exchange Act of 1934, as amended (15 U.S. Code (U.S.C.) 78m(d)), requires that a person or entity that owns or controls more than 5 percent of the registered securities of a company file notice with the SEC. On December 9, 2011, NRG filed a Schedule 13G with the SEC indicating an 11 percent ownership interest in NRG by Orbis Management, Ltd., and Orbis Asset Management, Ltd., both of which are Bermuda companies.

The staff noted further that the Chief Risk Officer of NRG is a citizen of Canada. Based on NRG's annual reports, the responsibilities of the Chief Risk Officer include oversight of certain financial risk functions.

Based on its review of the December 9, 2011, NRG Schedule 13G filing with the SEC concerning Orbis Management, Ltd., and Orbis Asset Management, Ltd., and identification of NRG's Chief Risk Officer being a citizen of Canada, the staff issued RAI 1.1.4-2 by letter dated May 22, 2012, requesting that the applicant provide the following information to address FOCD:

- Describe the type of shares (e.g., common or preferred stock) and shareholder rights of the shares of NRG that Orbis Management, Ltd., and Orbis Asset Management, Ltd., own as a result of the December 9, 2011, Schedule 13G filing with the SEC. In addition, state what rights Orbis Management, Ltd., and Orbis Asset Management, Ltd., will have to participate in matters affecting the management or operation of STP, Units 1 and 2, including, but not limited to, the right to nominate any Director(s) to STPNOC's Board of Directors.
- State whether there are any procedures in place to assure that Orbis Management, Ltd., and Orbis Asset Management, Ltd., shareholder rights in NRG—or any foreign entity or any entity that is owned, controlled, or dominated, directly or indirectly by a foreign entity—does not result in their participation in decisions concerning nuclear safety or security; obtaining responsibility for special nuclear material; or gaining access to restricted data. If so, provide a list of the procedures.
- State whether there are any unanimous consent requirements for decisions made by the Board of Directors and whether Orbis Management Ltd. and Orbis Asset Management Ltd. will have any right to participate in unanimous decisions. If so, provide a list of their rights.
- Describe the legal, contractual or financial arrangements, if any, between STPNOC, the three co-owners of STP, Units 1 and 2 (the City of Austin, CPS Energy, and NRG South Texas, LP), and Orbis Management Ltd. and Orbis Asset Management Ltd., or any foreign entity or any entity that is owned, controlled, or dominated, directly or indirectly, by a foreign entity.
- Describe the Chief Risk Officer's roles, responsibilities, and authority over STP, Units 1 and 2, regarding NRC activities, specifically as they relate to nuclear safety, security, reliability, or special nuclear material. In addition, state whether there are any procedures in place to assure that non-U.S. citizen Directors or Officers will not participate in decisions concerning nuclear safety or security; obtaining responsibility for special nuclear material; or gaining access to restricted data. If so, provide a list of the procedures.

In its response dated May 31, 2012, the applicant stated that the securities held by Orbis Management, Ltd., and Orbis Asset Management, Ltd., were Common Stock of NRG, as listed in item 2(d) of the Schedule 13G dated December 9, 2011, as well as subsequent SEC Schedule 13G filings, including the most recent filing dated April 3, 2012. The applicant stated that Orbis Management, Ltd., and Orbis Asset Management, Ltd., have the same shareholder voting rights with respect to these shares of Common Stock as NRG's other shareholders. The applicant stated that Orbis Management, Ltd., and Orbis Asset Management, Ltd., have no right to participate in matters affecting the management or operation of STPNOC and that Orbis Management, Ltd., and Orbis Asset Management, Ltd., have no rights to nominate any Director(s) to STPNOC's Board of Directors. In addition, the applicant stated that Orbis Management, Ltd., and Orbis Asset Management, Ltd., do not have any shareholder rights in NRG that could result in either company participating in decisions concerning nuclear safety or security; obtaining responsibility for special nuclear material; or gaining access to restricted data through its status as an NRG shareholder. NRG's shareholders do not have any right to participate in decisions concerning nuclear safety or security, or to obtain control or responsibility for special nuclear material, or gain access to restricted data. STPNOC maintains control over nuclear safety and security and has control and responsibility for any special nuclear material possessed pursuant to the licenses issued to STPNOC and the STP, Units 1 and 2, co-owners. According to the applicant, NRG South Texas LP is a licensed owner, but it does not possess any special nuclear material. Moreover, STPNOC, NRG, and NRG South Texas LP do not possess any restricted data.

The applicant further stated that no decisions made by NRG's Board of Directors or shareholders are required to be made by unanimous consent; thus, no shareholder of NRG has any unanimous consent rights. Orbis Management, Ltd., and Orbis Asset Management, Ltd., have no rights to participate in any "unanimous decisions." According to the applicant, other than Orbis Management, Ltd., and Orbis Asset Management, Ltd., being a shareholder of NRG, neither STPNOC nor NRG is aware of any legal, contractual, or financial arrangements between Orbis Management, Ltd., and Orbis Asset Management, Ltd., and STPNOC. Similarly, there are no arrangements between Orbis Management, Ltd., and Orbis Asset Management, Ltd., and any of the three co-owners of STP, Units 1 and 2. Subsequently, by letter dated April 30, 2013, the applicant informed the NRC that, as of December 31, 2012, the Orbis Management Ltd. and Orbis Asset Management Ltd. ownership in shares of NRG was 0%.

The applicant stated that the Chief Risk Officer has no role, responsibility, or authority over STP, Units 1 and 2, regarding NRC-regulated activities, specifically as they relate to nuclear safety, security, reliability, or special nuclear material, the Units 1 and 2 nuclear decommissioning fund decisions, or other financial matters regulated by the NRC. A Trustee, the Bank of New York Mellon, administers the NRG decommissioning trust fund, which is outside the administrative control of NRG in accordance with NRC requirements. According to the applicant, NRG activities related to the decommissioning trust fund are managed by NRG's Treasury Department; NRG's Treasurer reports directly to and is responsible to the Chief Financial Officer (CFO). The Chief Risk Officer also reports to the CFO and has no oversight authority for activities of the Treasury Department. In addition, according to the applicant, the NRG decommissioning trust find is subject to the ongoing jurisdiction and oversight of the Public Utility Commission of Texas (PUCT). Through its regulations and orders, the PUCT imposes investment standards and other requirements on the decommissioning trust fund and establishes the amounts of annual collections from ratepayers to be deposited into the trust fund.

Additionally, the applicant stated that STPNOC is subject to U.S. control, and STPNOC will exercise authority over nuclear safety and security matters free from any potential for foreign domination or control over its decisionmaking under the AEA. In particular, STPNOC will remain free from any foreign control or domination with regard to security matters and remains subject to ongoing U.S. Government oversight regarding foreign ownership, control, or influence (FOCI). STPNOC maintains a facility security clearance, and it has individual employees who maintain U.S. Government security clearances. In connection with ongoing oversight of these security clearances, STPNOC periodically updates a "Certificate Regarding Foreign Interests," using Standard Form 328 (SF 328), which provides for disclosures regarding potential FOCI. SF 328 includes various questions regarding a range of potential areas of foreign influence, which includes, but is not limited to, debt, foreign source income, and contracts and agreements with foreigners. Material changes to answers to any questions in SF 328 are reported to the NRC in accordance with 10 CFR 95.17(a)(1). In addition, submittals to U.S. Government security officials include the U.S. Department of Energy's forms identifying owners, officers, directors, and executive personnel, and their citizenship, which are submitted and periodically updated for STPNOC, as well as the City of Austin, CPS Energy, and the NRG entities in the chain of control of NRG South Texas LP. As previously discussed, the City of Austin, CPS Energy, and NRG South Texas LP do not own STPNOC, but they are treated like owners in connection with the Government's security reviews because they have the right to appoint the STPNOC Participant Directors. The staff notes that STPNOC maintains acceptable mitigation measures in place relating to FOCI and safeguarding classified information.

In its May 31, 2012, submittal, the applicant stated that NRG previously established a Nuclear Oversight Committee (NOC) of the NRG Board and a Nuclear Oversight Subcommittee, both of which are made up entirely of U.S. citizens, and Board authority has been delegated to the Nuclear Oversight Subcommittee over any matters that could have implications for compliance with 10 CFR 50.38, which states: "Any person who is a citizen, national, or agent of a foreign country, or any corporation, or other entity which the Commission knows or has reason to believe is owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government, shall be ineligible to apply for and obtain a license." However, on December 21, 2013, STPNOC submitted a request titled "Review of License Renewal Application Safety Evaluation with Open Items – Proposed License Conditions" in which the applicant requests that the NRC delete the license condition requiring that, among other things, "NRG will maintain the NRC-approved NOC and Nuclear Oversight Subcommittee…" Based on the staff's evaluation of open-source analysis and the totality of facts, the NRC staff finds that there are no longer FOCD issues. Therefore, the NRC staff finds that any existing or proposed license conditions related to FOCD can be deleted.

Based on its independent analysis of the information provided in the application and subsequent communications with the NRC on the subject of FOCD, the NRC staff does not know or have reason to believe that STPNOC is owned, controlled, or dominated by a foreign interest. Therefore, the requirements of 10 CFR 54.17 and 10 CFR 50.38 are met.

Insurance and Indemnity

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 LRA Section 1.1.10:

> 10 CFR 54.19(b) requires that License Renewal applications include, "…conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license."

> The current indemnity agreement B-108 for STP Units 1 and 2, states in Article VII that the agreement shall terminate at the time of expiration of that license specified in Item 3 of the Attachment to the agreement, which is the last to expire. Item 3 of the Attachment to the indemnity agreement, as amended, lists license numbers NPF-76, and NPF-80.
>
> STPNOC requests that conforming changes be made to the indemnity agreement, and/or the Attachment to the agreement, as required, to ensure that the indemnity agreement continues to apply during both the terms of the current licenses and the terms of the renewed licenses. STPNOC understands that no changes may be necessary for this purpose if the current license number is retained.

The staff intends to maintain the original license 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 are met.

Contents of Application—Technical Information

Pursuant to 10 CFR 54.21, "Contents of Application—Technical Information," the NRC requires that the LRA contain the following portions:

(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
(d) a UFSAR supplement

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

Pursuant to 10 CFR 54.21(b), the NRC requires the applicant to submit an LRA amendment that identifies any CLB changes to the facility affecting the contents of the LRA, including the UFSAR supplement, each year following submission of the LRA and at least 3 months before the scheduled completion of the staff's review. The applicant met the update requirements by submitting seven annual updates, by letters dated November 30, 2011, October 29, 2012, October 28, 2013, October 22, 2014, October 22, 2015, June 28, 2016, and April 4, 2017, to summarize the CLB changes that occurred since submittal of the LRA through the update's issue date.

Pursuant to 10 CFR 54.22, the staff requires that an applicant's LRA include changes or additions to the technical specifications necessary to manage aging effects during the period of extended operation. In LRA Section 1.4, the applicant stated that Appendix D satisfies the requirements of 10 CFR 54.22, and stated "[s]ince no Technical Specification changes are requested, this Appendix is not used." Therefore, the applicant met the requirements of 10 CFR 54.22.

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

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

The GALL Report, Revision 2, dated December 2010, and the SRP-LR, Revision 2, dated December 2010, have incorporated all previously issued ISGs up to that date.

Table 1.4-1 shows the current set of approved ISGs as well as the SER sections to which the ISG may apply.

Table 1.4-1 Current Interim Staff Guidance

ISG Issue (Approved ISG Number)	Purpose	SER Section
"Aging Management of Stainless Steel Structures and Components in Treated Borated Water" (LR-ISG-2011-01)	This ISG provides guidance on one acceptable approach for managing the effects of aging during the period of extended operation for stainless steel structures and components exposed to treated borated water within the scope of license renewal.	SER Sections 3.2 and 3.3
"Aging Management Program for Steam Generators" (LR-ISG-2011-02)	This guidance evaluates the suitability of using Revision 3 of NEI 97-06 for implementing an applicant's steam generator aging management program (AMP).	SER Section 3.0.3.1.3
"Generic Aging Lessons Learned (GALL) Report Revision 2 AMP XI.M41, 'Buried and Underground Piping and Tanks'" (LR-ISG-2011-03)	This ISG gives additional guidance on managing the effects of aging on buried and underground piping and tanks.	SER Section 3.0.3.2.14
"Updated Aging Management Criteria for Reactor Vessel Internal Components of Pressurized Water Reactors" (LR-ISG-2011-04)	This ISG updates the GALL Report, Revision 2, and SRP-LR, Revision 2, to ensure consistency with MRP-227-A for the aging management of age-related degradation for components of pressurized water reactor vessel internal components during the term of a renewed operating license.	SER Section 3.0.3.3.2
"Ongoing Review of Operating Experience" (LR-ISG-2011-05)	This 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
"Wall Thinning Due to Erosion Mechanisms" (LR-ISG-2012-01)	This ISG gives additional guidance on managing the effects of wall thinning due to erosion mechanisms.	Sections 3.0.3.2.4 and 3.0.3.2.6

ISG Issue (Approved ISG Number)	Purpose	SER Section
“Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation” (LR-ISG-2012-02)	This ISG gives guidance on managing the effects of aging for internal surfaces, fire water system, atmospheric storage tanks, and corrosion under insulation.	Sections 3.0.3.2.10 and 3.3.2.3.17
“Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks” (LR-ISG-2013-01)	This ISG gives guidance on aging management for coating or lining integrity for internal coatings/linings on in-scope piping, piping components, heat exchangers, and tanks.	Sections 3.0.3.2.6, 3.0.3.2.10, and 3.0.3.2.18
“Changes to Buried and Underground Piping and Tank Recommendations” LR-ISG-2015-01	This ISG replaces aging management program (AMP) XI.M41, “Buried and Underground Piping and Tanks,” and the associated Updated Final Safety Analysis Report Summary Description in LR-ISG-2011-03, “Changes to the Generic Aging Lessons Learned (GALL) Report, Revision 2 Aging Management Program (AMP) XI.M41, ‘Buried and Underground Piping and Tanks’.”	Section 3.0.3.2.14
“Changes to Aging Management Guidance for Various Steam Generator Components” LR-ISG-2016-01	This ISG replaces aging management program (AMP) XI.M19 “Steam Generator” and the aging management review (AMR) items in NUREG-1801, “Generic Aging Lessons Learned (GALL) Report,” Revision 2, and NUREG-1800, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants.”	Section 3.0.3.1.3

1.5 Summary of Open Items

As a result of its review of the LRA, the staff closed the remaining open item discussed in the SER with Open Items issued in October 2016. 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.

A summary of the closure of the remaining open item (OI) is as follows:

OI 3.0.3.3.3-2: Insufficient details provided regarding applicant’s Selective Leaching of Aluminum Bronze Aging Management Program (AMP).

In the 2016 SER with Open Items, the staff lacked sufficient information to complete its evaluation of the Selective Leaching of Aluminum Bronze Program. The open issues were as follows:

- sizing of extruded piping tee repair volume
- clarification of parameters monitored or inspected for all of the inspection methods conducted in accordance with the AMP
- sample size for volumetric inspections
- the threshold for the number of defective welds resulting in further inspections

- selection criteria for weld inspections
- the impact of the potential resistance of external coatings of buried piping welds in regard to detecting leaks on the surface
- the program does not cite a method to monitor or trend results
- vagueness of acceptance criteria for weld defects
- threshold for increased inspections when adverse inspection results are detected
- corrective actions are not identified for all potential inspection results

Based on the staff's interaction with the applicant during public meetings and supplemental audits, and the final revised Selective Leaching of Aluminum Bronze Program and associated UFSAR supplement dated through May 2, 2017, all open issues listed above have been addressed through revisions to the aging management program and commitments. The staff's evaluation of these open issues is documented in SER Section 3.0.3.3.3 in the appropriate program element (e.g., sizing of extruded tees is documented in the "scope of program" program element). The staff's concerns are resolved and OI 3.0.3.3.3-2 is closed.

1.6 Summary of Confirmatory Items

An item is considered confirmatory if the staff and the applicant have reached a satisfactory resolution, but the applicant has not yet formally submitted the resolution. The staff assigns a unique identifying number to each confirmatory item. The staff has identified no confirmatory items for this SER.

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 four proposed license conditions.

- This license condition requires the applicant to include the UFSAR supplement required by 10 CFR 54.21(d) in the next UFSAR update, as 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 in accordance with the criteria set forth in 10 CFR 50.59 and otherwise complies with the requirements in that section.
- This license conditions requires that the License Renewal UFSAR Supplement, as updated by the license condition above, describe certain programs to be implemented and activities to be completed before the period of extended operation, as follows:
  - (a) The applicant shall implement those new programs and enhancements to existing programs no later than 6 months before the period of extended operation.
  - (b) The applicant shall complete those activities by the 6-month date before the period of extended operation or the end of the last refueling outage before the period of extended operation, whichever occurs later.
  - (c) The applicant shall notify the NRC in writing within 30 days after having accomplished item (a) above and include the status of those activities that have been or remain to be completed in item (b) above.

- This license condition requires that all capsules in the reactor vessel that are removed and tested must meet the test procedures and reporting requirements of American Society of Testing and Materials (ASTM) E 185-82 to the extent practicable for the configuration of the specimens in the capsule. The license condition also states that capsules placed in storage must be maintained for future insertion, and that any changes to capsule withdrawal schedules (including spare capsules) or storage requirements must be approved by the NRC prior to implementation.
- This license condition requires that, prior to entering the period of extended operation, destructive examinations be conducted on the lesser of 20 percent or 25 of the aboveground welds susceptible to loss of material due to selective leaching of aluminum bronze without backing rings and the lesser of 20 percent or 25 of the aboveground welds susceptible to loss of material due to selective leaching of aluminum bronze with backing rings. The results of the examinations shall be evaluated in accordance with the acceptance criteria, and corrective actions shall be taken when the acceptance criteria are not met, as specified in the license renewal application, as amended through supplements dated May 2, 2017.

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 the applicant to identify the structures, systems, and components (SSCs) within the scope of license renewal in accordance with 10 CFR 54.4(a). In addition, the license renewal application (LRA) must contain an integrated plant assessment (IPA) that identifies and lists those structures and components (SCs) contained in the SSCs determined to be within the scope of license renewal, which are subject to an aging management review (AMR).

LRA Section 2.1, "Scoping and Screening Methodology," describes the scoping and screening methodology used to identify the SSCs at the South Texas Project Electric Generating Station (STP), Unit 1 and Unit 2, within the scope of license renewal and the SCs subject to an AMR. The staff reviewed the scoping and screening methodology of the STP Nuclear Operating Company (STPNOC or the applicant) to determine whether it meets the scoping requirements of 10 CFR 54.4(a) and the screening requirements of 10 CFR 54.21.

In developing the scoping and screening methodology for the LRA, the applicant stated that it considered the following:

- 10CFR Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants" (the Rule)
- statements of consideration for the Rule in the *Federal Register* (FR) (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 or the staff), other applicants, and NEI

2.1.2 Summary of Technical Information in the Application

LRA Section 2 provides the technical information required by 10 CFR 54.21(a). LRA Section 2.1 describes the applicant's process used to identify the SSCs that meet the license renewal scoping criteria contained in 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). This safety evaluation report (SER), contains sections entitled "Summary of Technical Information in the Application," which provide information taken directly from the LRA.

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 2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," (SRP-LR), Section 2.1, "Scoping and Screening Methodology." The following regulations form the basis for the acceptance criteria for the scoping and screening methodology review:

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

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

- Section 2.1—to ensure that the applicant described a process for identifying SSCs that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)
- Section 2.2—to ensure that the applicant described a process for determining the SCs that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1) and (a)(2).

In addition, the staff conducted a scoping and screening methodology audit at the STP facility located in south-central Matagorda County, 8 miles north-northwest of the town of Matagorda, Texas, during the week of May 16-19, 2011. 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 qualifications of the LRA development team.

The staff evaluated the quality attributes of the applicant's aging management program (AMP) activities described in LRA Appendix A, "Final Safety Analysis Report Supplement," and Appendix B, "Aging Management Programs." On a sampling basis, the staff performed a system review of the auxiliary feedwater (AFW); essential chilled water portion of the heating, ventilation, and air conditioning (HVAC) system; essential cooling water (ECW); emergency diesel generators; and the turbine building, 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 confirm 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 audit trip report, dated September 6, 2011 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML11230A003), to confirm 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 the 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:

- CLB documents
- engineering drawings
- technical position papers
- master equipment database

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. This review ensured the applicant 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 the SSCs that are within the scope of the Rule and for identifying the SCs contained in systems within the scope of license renewal, which are subject to an AMR. During the review of the implementing procedures, the staff focused on the consistency of the applicant's detailed procedural guidance with the information contained in the LRA. This included the implementation of NRC staff positions, as documented in the SRP-LR, and the information in the applicant's responses, dated August 23, 2011, and November 21, 2011, to the staff's requests for additional information (RAIs) dated July 28, 2011, and September 21, 2011.

After reviewing the LRA and supporting documentation, the staff found 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 development activities.

Sources of Current Licensing Basis Information. Pursuant to 10 CFR 54.21(a)(3), for each SC determined to be subject to an AMR, demonstration is required to show 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 CLB is defined in 10 CFR 54.3(a), in part, as 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 updated final safety analysis report (UFSAR)). The CLB also includes licensee commitments remaining in effect that were made in docketed licensing correspondence, such as licensee responses to NRC bulletins, generic letters, and enforcement actions, and licensee commitments documented in NRC safety evaluations or licensee event reports. The staff considered the scope and depth of the applicant's CLB review to confirm that the methodology is sufficiently comprehensive to identify SSCs within the scope of license renewal, as well as SCs requiring an AMR.

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 quality classification information (which is contained in the master equipment database (MED)), controlled drawings, analyses, and reports. 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 applicant's primary sources for system identification and component safety classification information were the MED, the Q-List (a specific portion of the MED that identifies the quality classification of SSCs), the UFSAR, and plant drawings. During the audit, the staff discussed the applicant's administrative controls for the MED, the Q-List, and the other information sources used to confirm system information as described by plant procedures. Based on a review of the administrative controls, and a sample of the system classification information contained in the applicable documentation, the NRC staff concludes that the applicant established adequate measures to control the integrity and reliability of 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 considered during the LRA development. The staff found that LRA Section 2.1 provided a description of the CLB and related documents used during the scoping and screening process, which 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.

During the review of the LRA and associated CLB documents, the staff found that the applicant had received approval for an exemption from special treatment requirements (the exemption) in an August 3, 2001, NRC letter. The NRC letter and SER contained the staff's analysis and conclusion approving the STP exemption from certain specific requirements based on the applicant's analysis and identification of non-risk significant (NRS) or low safety significance (LSS) SSCs. The staff determined that additional information would be required to complete its review. Therefore, by letter dated September 21, 2011, the staff issued RAI 2.1-4, requesting that the applicant indicate whether the determination that SSCs were NRS or LSS resulted in (1) reclassification of those SSCs from safety-related to nonsafety-related, (2) omission from the scope of license renewal, or (3) exclusion from an AMR.

The applicant responded to RAI 2.1-4 by letter dated November 21, 2011, stating, in part, that components were not excluded from the scope of license renewal as a result of being reclassified under the special treatment exemptions of 10 CFR 50.69. The applicant stated that no LSS or NRS components were reclassified from safety-related to nonsafety-related, and the components satisfied the quality assurance requirements of 10 CFR Part 50, Appendix B, with regard to design control, nonconformance controls, and corrective actions. The applicant also stated that AMRs were performed on all SSCs within the scope of license renewal regardless of a special treatment classification.

The staff reviewed the response to RAI 2.1-4 and determined that the applicant had not excluded SSCs classified as NRS or LSS from the scope of license renewal based on the application of the exemption. In addition, the applicant had performed AMRs for SCs, contained within the population of SSCs classified as NRS or LSS, when applicable. The staff's concerns in RAI 2.1-4 are resolved.

2.1.3.1.3 Conclusion

Based on its review of LRA Section 2.1, the detailed scoping and screening implementing procedures, the results from the scoping and screening audit, and the applicant's response to RAI 2.1-4, the staff concludes that the applicant's use of implementing procedures and consideration of document resources, including CLB information, is 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:

- Implementing procedures and additional guidance documents and activities, including license renewal drawings, were used.
- A license renewal data management tool was used to manipulate data and record scoping and screening evaluations and to generate license renewal documents.
- LRA reviews were performed by a license renewal team consisting of subject matter experts and senior management.
- Discipline leads and license renewal project management reviewed and approved scoping and screening documents.

- Additional LRA oversight and review was provided through an industry peer review, quality assessment, industry expert reviews, and consideration of industry lessons learned.

During the scoping and screening methodology audit, the staff performed a sample review of reports and LRA development procedures and guides, reviewed the applicant’s documentation of the activities performed to assess the quality of the LRA, and held discussions with the applicant’s license renewal personnel regarding quality assurance controls as applied to the development of the LRA. The staff concluded that the applicant’s activities provide assurance that LRA development activities were performed consistently with the applicant’s license renewal program requirements.

2.1.3.2.2 Conclusion

Based on its review of pertinent LRA development guidance, discussion with the applicant’s license renewal staff regarding quality assurance controls as applied to the development of the LRA, 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 are adequate to ensure 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 processes to ensure the guidelines and methodology for the scoping and screening activities were applied in a consistent and appropriate manner. As outlined in the implementing procedure, the applicant requires training for personnel participating in the development of the LRA. The activities conducted by the applicant included the following:

- Personnel were trained to the applicable project instructions and desktop guides in accordance with their functions.
- License renewal and subject matter expert training included LRA overview and integrated plant assessment fundamentals; license renewal data management tool training for reviewers; and participation in a readiness review.

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. In addition, the staff discussed training activities with the applicant’s management and license renewal project personnel to understand the implementation of the training process and procedures. Based on the review completed, the staff concluded that the applicant developed and implemented adequate procedures to control the training of personnel performing LRA activities.

2.1.3.3.2 Conclusion

Based on its review of the applicant’s training processes, the staff concludes that the applicant developed and implemented adequate procedures to train personnel 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

Based on its review of information provided in LRA Section 2.1, 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 personnel 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 2.1.2, "Scoping Criteria," describes the applicant's methodology used to scope SSCs pursuant to the requirements of the 10 CFR 54.4(a) criteria. The LRA states that that the scoping process identified the SSCs that are safety-related and perform or support an intended function for responding to a design basis event (DBE); are nonsafety-related but their failure could prevent accomplishment of a safety-related function; or support a specific requirement for one of the regulated events applicable to license renewal. LRA Section 2.1.1, "Introduction," states that the scoping methodology used by STP 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" states, in part, the following:

> Safety-related design classifications for systems, structures, and components are described in the UFSAR and in plant specification *Quality Classification of Structures*; safety-related classifications for components are documented on engineering drawings and in the master equipment database. The safety-related classification as described in these source documents was used to identify SSCs satisfying one or more of the criteria of 10 CFR 54.4(a)(1) and include them within the scope of license renewal. STP-specific definitions for safety-related in UFSAR Section 3.2 are consistent with the definition of safety-related provided in 10 CFR 54.4(a)(1).
>
> Quality group classification, safety class terminology is utilized for the classification of components and structures. This terminology correlates to the NRC Quality Group designations for water, steam, and radioactive waste-containing mechanical components. Components and structures with quality group classifications SC1, SC2 and SC3 are within the scope of license renewal for (a)(1).
>
> The exposure guidelines used for STP license renewal are the same as 10 CFR 54.4. In addition to the guidelines of 10 CFR 100, 10 CFR 54.4(a)(1)(iii) references the dose guidelines of 10 CFR 50.34(a)(1) and 10 CFR 50.67(b)(2). The exposure guidelines of 10 CFR 50.67(b) address the use of alternate source terms and are applicable under the STP CLB for the electrical auxiliary building and control room HVAC system, as a result of a locked-rotor accident and for the

steam generator tube rupture analysis with a failed-open main steam isolation valve.

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, SRP-LR Section 2.1.3, "Review Procedures," states, in part:

> The set of DBEs as defined in the Rule is not limited to Chapter 15 (or equivalent) of the USAR [updated safety analysis report]. 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 USAR, 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 STP. The staff reviewed the applicant's basis documents, which described design basis conditions in the CLB and addressed events defined by 10 CFR 50.49(b)(1) and 10 CFR 54.4(a)(1). The STP UFSAR and basis documents discussed events such as internal and external flooding, tornados, and missiles. The staff concluded 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 of the scoping and screening process with the applicant's personnel who were responsible for these evaluations to better understand the implementation of the scoping and screening process and how the process produced the results.

The staff reviewed the applicant's evaluation of the Rule and CLB definitions pertaining to 10 CFR 54.4(a)(1) and determined that the CLB definition of safety-related met the definition of safety-related specified in the Rule. The staff reviewed a sample of the license renewal scoping results for the AFW, essential chilled water/HVAC, ECW, emergency diesel generators, and the turbine building to provide additional assurance that the applicant adequately implemented its scoping methodology with respect to 10 CFR 54.4(a)(1). The staff confirmed 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.

During its onsite audit the week of May 16-19, 2011, the staff determined, through a review of license renewal implementing procedures and discussions with the applicant, that a quality group classification, "Quality Class 4; QC-4," had also been used in identifying SSCs to be included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). However, the use of QC-4 was not addressed in the LRA. The staff determined that additional information would be required to complete its review. Therefore, by letter dated July 28, 2011, the staff issued RAI 2.1-1, requesting that the applicant address whether components identified as QC-4 in the plant equipment database or other documents had been evaluated to identify SSCs to be included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1).

The applicant responded to RAI 2.1-1 by letter dated August 23, 2011, and stated, in part, that the units' SSCs that are classified as QC-4 are safety-related and are included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). The applicant also stated that nonsafety-related SSCs, including those classified as QC-4, whose failure could impact any of the functions identified in 10 CFR 54.4(a)(1), are included within the scope of license renewal.

The staff reviewed the applicant's response to RAI 2.1-1 and determined that the applicant had considered SSCs identified as QC-4 as safety-related and had included the SSCs within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(1). In addition, the applicant had considered nonsafety-related SSCs, with the potential to fail and impact the performance of the intended functions of QC-4 SSCs, and included the nonsafety-related SSCs within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2). The staff's concerns in RAI 2.1-1 are resolved.

2.1.4.1.3 Conclusion

Based on its review, the staff concludes that the applicant's methodology for identifying safety-related systems and structures relied on to remain functional during and following DBEs and including them within the scope of license renewal 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)—Nonsafety-Related Affecting Safety-Related," states, in part, the following:

> Nonsafety-Related SSCs Performing Safety-Related 10 CFR 54.4(a)(1) Functions

The STP UFSAR and other current licensing basis documents were reviewed for nonsafety-related plant systems or structures, to determine whether nonsafety-related systems or structures were credited with performing a safety-related function. STP does not have nonsafety-related systems or structures credited in CLB documents that perform a safety-related function.

Nonsafety-Related SSCs Directly Connected to Safety-Related SSCs

Nonsafety-related SSCs that are directly connected to safety-related SSCs were included within the scope of license renewal to ensure structural integrity of the safety-related SSC up to the first seismic anchor or equivalent anchor past the safety/nonsafety interface. In cases where seismic or equivalent anchors were not available to serve as the license renewal boundary, the bounding condition discussed in NEI 95-10, Appendix F, were utilized to establish the license renewal boundary.

Nonsafety-Related SSCs with Interaction with Safety-Related SSCs

Nonsafety-related SSCs that contain fluid or steam, and are located in the same room or areas that contain safety-related SSCs are included in scope for potential leakage boundary (spatial) interaction under criterion 10 CFR 54.4(a)(2) (regardless of the system pressure). The rooms and areas of concern for potential leakage boundary (spatial) interaction were identified based on a review of the CLB and design drawings and considered for potential communication with other rooms that may contain 10 CFR 54.4(a)(1) components. Plant walk downs were performed, as necessary, to confirm the spatial interaction boundaries. Supports for nonsafety-related SSCs are included in scope to prevent adverse interaction with safety-related SSCs.

2.1.4.2.2 Staff Evaluation

Pursuant to 10 CFR 54.4(a)(2), the applicant must consider all nonsafety-related SSCs, whose failure could prevent the satisfactory accomplishment of safety-related functions, 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 accomplishment of safety functions as follows:

- consideration of missiles, cranes, flooding, and high-energy line breaks (HELBs)
- nonsafety-related SSCs connected to safety-related SSCs

- nonsafety-related SSCs in proximity to safety-related SSCs
- mitigative and preventive 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 should not consider hypothetical failures but, rather, should base their evaluation on the plant's CLB, engineering judgment and analyses, and relevant operating experience. NEI 95-10 further describes operating experience as all documented plant-specific and industry-wide experience that can be used to determine the plausibility of a failure. Documentation would include NRC generic communications and event reports, plant-specific condition reports (CRs), 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 procedure 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.

<u>Nonsafety-Related SSCs Required To Perform a Function that Supports a Safety-Related SSC</u>. 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 and the applicant's 10 CFR 54.4(a)(2) implementing procedure. The staff confirmed that the applicant had reviewed the UFSAR, plant drawings, 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 to determine if there were nonsafety-related systems that perform functions that support safety-related intended functions to be included within the scope of license renewal, as required by 10 CFR 54.4(a)(2).

<u>Nonsafety-Related SSCs Directly Connected to Safety-Related SSCs</u>. 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 procedure. The applicant had reviewed the safety-related to nonsafety-related interfaces for each mechanical system 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 in order to maintain the integrity of the safety-related SSCs, the applicant had used a combination of the following to identify the bounding portion of nonsafety-related piping systems to include within the scope of license renewal:

- seismic anchors
- equivalent anchors

- bounding conditions described in NEI 95-10 Revision 6, Appendix F (base-mounted component, flexible connection, buried piping exiting the ground, 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 and the applicant's 10 CFR 54.4(a)(2) implementing procedure. The applicant had 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.

LRA Section 2.1.2.2 and the applicant's implementing procedure state that the applicant had 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 had 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 had 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 and the applicant's implementing procedure state that the applicant had also used a preventive approach, which considered the impact of nonsafety-related SSCs contained in the same space as safety-related SSCs. The staff determined that the applicant had evaluated all nonsafety-related SSCs, which contain liquid or steam and are 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 located inside structures that contain safety-related SSCs were included within the scope of license renewal, unless they were evaluated and determined not to contain safety-related SSCs.

During its onsite audit the week of May 16-19, 2011, the staff determined that the method used to address the potential for nonsafety-related SSCs to impact safety-related SSCs located in the turbine building—as provided during discussions with the applicant—was not consistent with the method provided in the LRA and the applicant's implementing procedures. The staff performed a plant walkdown of the safety-related SSCs located in the turbine building (feedwater regulating control valves and associated air solenoid valves and limit switches) and determined that there were nonsafety-related SSCs located within the vicinity of the safety-related SSCs. The LRA and the applicant's implementing procedures stated that nonsafety-related piping and structures that could potentially interact with the safety-related solenoid valves and limit switches were included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). However, during audit discussions with the staff, the applicant stated that the safety-related solenoid valves and limit switches were qualified to withstand the effects of the failure of nonsafety-related SSCs within the vicinity of the safety-related SSCs; therefore, the nonsafety-related SSCs were not included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). The staff determined that it needed additional information to complete its review. Therefore, by letter dated July 28, 2011, the staff issued RAI 2.1-2, requesting that the applicant provide the technical basis for its determination that the nonsafety-related SSCs located in the vicinity of the safety-related SSCs located in the turbine building were not included within the scope of license renewal.

The applicant responded to RAI 2.1-2 by letter dated August 23, 2011, and stated, in part, that it had performed a walkdown of the feedwater regulating valves and their associated safety-related solenoid valves and limit switches in order to identify nonsafety-related components whose failure could affect those safety-related components. The applicant also stated that it included within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2), those components in the immediate vicinity of, and having a potential for spatial interaction with, the solenoid valves and limit switches to prevent the satisfactory performance of their intended functions. Furthermore, the applicant stated that the feedwater regulating valves and lines were within the scope of license renewal and subject to periodic monitoring of external surfaces, as discussed in LRA Section B2.1.20, and that the solenoid valves, limit switches, and associated circuits were environmentally qualified for steam line break, water spray, and harsh temperature environments. The applicant also stated that it did not include any high-energy, nonsafety-related components that were not in the immediate vicinity and could not impact functions of the safety-related components and that its methodology was consistent with NEI 95-10, Section 5.2.3.2, Appendix F. Finally, the applicant stated that it had not identified any previously unidentified components as a result of its review.

The applicant provided a supplemental response to RAI 2.1-2, dated December 7, 2011. This response provided additional information including the specific nonsafety-related systems, or portions of systems, that were included in-scope for 10 CFR 54.4(a)(2) as a result of the potential for interaction with the safety-related components in the turbine buildings. It also identified the applicable license renewal drawings.

The staff reviewed the applicant's responses to RAI 2.1-2 and determined that the applicant had provided an acceptable basis for not including fluid-filled nonsafety-related SSCs within the vicinity of safety-related SSCs because the safety-related SSCs were qualified for the potential environment (environmentally qualified components). In addition, the staff determined that the applicant had included the nonsafety-related SSCs with the potential for direct impact (other than fluid interaction) within the scope of license renewal in accordance with 10 CFR 54.4(a)(2), as appropriate. The staff's concerns in RAI 2.1-2 are resolved.

During the scoping and screening methodology audit performed onsite May 16-19, 2011, the staff noted that the applicant had performed a plant walkdown subsequent to the submittal of the LRA. During this walkdown, the applicant identified additional SSCs to be included within the scope of license of renewal in accordance with 10 CFR 54.4(a)(2). The staff determined that additional information would be required to complete the review of the applicant's scoping methodology. Therefore, by letter dated July 28, 2011, the staff issued RAI 2.1-3, requesting that the applicant provide information on the walkdown performed subsequent to the submittal of the LRA and its impact on license renewal.

The applicant responded to RAI 2.1-3 by letter dated August 23, 2011, and stated that it had not included some SSCs from the mechanical auxiliary building (MAB) or from the fuel handling building (FHB) within the scope of license renewal due to an incorrect interpretation of seismic II/I information from drawings. The applicant stated that it incorrectly concluded that non-seismic II/I areas would not contain safety-related components, even though the rooms could have included safety-related components above nonsafety-related components. The applicant also stated that, for each room that had been excluded from a 10 CFR 54.4(a)(2) evaluation based on that approach, it performed walkdowns to identify potential spatial interactions between seismic II/I and non-seismic II/I areas. The applicant also stated that it determined that some non-seismic II/I areas contain safety-related components above nonsafety-related components; the applicable components were then identified as being within the scope of license renewal per 10 CFR 54.4(a)(2) and were placed into appropriate AMPs.

The staff reviewed the applicant's response to RAI 2.1-3 and determined that the applicant had initially relied on seismic II/I information contained in the CLB to identify nonsafety-related SSCs, with the potential to impact the performance of safety-related SCCs, to be included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). However, upon further review, subsequent to submittal of the LRA, the applicant determined that the method used did not identify all nonsafety-related SSCs with the potential to impact the performance of safety-related SCCs. Following this determination, the applicant performed walkdowns of the applicable MAB and FHB spaces and identified additional nonsafety-related SSCs with the potential to impact safety-related SSCs, and it provided this additional information to the staff in response to RAI 2.1-3. The staff's concerns in RAI 2.1-3 are resolved.

Based on review of the LRA, the results of the scoping and screening methodology audit, and the applicant's responses to RAIs 2.1-2 and 2.1-3, the staff confirmed that nonsafety-related SSCs with the potential for spatial interaction with safety-related SSCs were appropriately included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

2.1.4.2.3 Conclusion

Based on its review of the applicant's scoping process, discussions with the applicant, and review of the information provided in the response to RAIs 2.1-2 and 2.1-3, the staff concludes that the applicant's methodology for identifying and including nonsafety-related SSCs, whose failure could prevent satisfactory accomplishment of the intended functions of safety-related SSCs, within the scope of license renewal, is consistent with 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 2.1.2.3.1, "Fire Protection," states, in part, the following:

> The STP CLB for Fire Protection consists of 10 CFR 50.48(a), 10 CFR [Part] 50 Appendix A General Design Criteria (GDC) 3, STPEGS Operating License, Condition 2.E, NUREG-0781, SER and SSERs [Supplemental Safety Evaluation Reports] 2, 3, 4, 5, and 7, UFSAR 9.5.1, and Fire Hazards Analysis Report. These documents identify the features required for STP to demonstrate compliance with 10 CFR 50.48 as described in the SER and supplements. SSCs classified as satisfying criterion 10 CFR 54.4(a)(3) related to fire protection are identified as within the scope of license renewal.

LRA Section 2.1.2.3.2, "Environmental Qualification," states, in part, the following:

> UFSAR Section 3.11.2 states that safety-related equipment and components located in a harsh environment are qualified by test or combination of test and analysis in accordance with the requirements of 10 CFR 50.49 and NUREG-0588. Components within the scope of the STP EQ [Environmental Qualification] Program, which demonstrate compliance with 10 CFR 50.49 and the systems containing those components are classified as satisfying criterion 10 CFR 54.4(a)(3) and are identified as within the scope of license renewal.

LRA Section 2.1.2.3.3, "Pressurized Thermal Shock," states, in part, that "[a] position paper was developed to review the licensing basis for pressurized thermal shock (PTS) at STP. The only component within the scope of the license renewal rule for pressurized thermal shock is the reactor pressure vessel."

LRA Section 2.1.2.3.4, "Anticipated Transients without Scram," (ATWS) states, in part, that "ATWS equipment required by 10 CFR 50.62 is described in UFSAR Section 7.8, ATWS Mitigation System Actuation Circuitry. ATWS SSCs are within the scope of license renewal."

LRA Section 2.1.2.3.5 "Station Blackout," states, in part, the following:

> UFSAR Section 8.3.4 discusses SBO [systems, structures and components] and quality assurance program requirements. The SSCs identified in the SBO review were used in scoping evaluations to identify SSCs that demonstrate compliance with 10 CFR 50.63. SSCs classified as satisfying criterion 10 CFR 54.4(a)(3) related to station blackout are identified as within the scope of license renewal.

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 was relied on to perform functions meeting the requirements of the NRC's regulations regarding fire protection, environmental qualification (EQ), ATWS, PTS, and station blackout (SBO). During the audit, the staff met with the applicant to discuss the applicant's methodology for scoping and screening of SSCs based on the scoping criteria in 10 CFR 54.4(a)(3), reviewed the topical reports associated with the regulated events, reviewed boundary scoping drawings, and reviewed the LRA for the development and approach taken to complete the scoping process for these regulated safety systems.

The staff confirmed that the applicant's implementing procedure was used for identifying SSCs within the scope of license renewal pursuant to 10 CFR 54.4(a)(3). The applicant evaluated the CLB 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 scoping reports for the systems and structures in-scope for regulated events. The staff determined that the scoping report results 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 systems and structures in the scope of license renewal required for fire protection are identified in the fire protection topical report and the CLB documents, primarily UFSAR Section 9.5.1 and the fire hazards analysis report (FHAR). Selected scoping reports for the systems and structures identified in the fire protection topical report were reviewed in conjunction with the LRA, CLB information, and boundary drawings to validate the methodology for including the appropriate systems and structures within the scope

of license renewal. The staff determined that the applicant's scoping included SSCs that perform intended functions to meet the requirements of 10 CFR 50.48. Based on its review of the CLB documents and the sample review, the staff determined that the applicant's scoping methodology was adequate for including SSCs credited in performing fire protection functions within the scope of license renewal in accordance with 10 CFR 54.4(a)(3).

Environmental Qualification. The staff confirmed that the applicant's scoping documents required the inclusion of safety-related electrical equipment, nonsafety-related electrical equipment whose failure under postulated environmental conditions could prevent satisfactory accomplishment of safety functions of the safety-related equipment, and certain post-accident monitoring equipment, as defined in 10 CFR 50.49. The staff determined that the applicant used the CLB, the UFSAR, and STP Special Equipment Qualification Masterlist File (a report from the EQ database) to identify SSCs necessary to meet the requirements of 10 CFR 50.49. The STP Special Equipment Qualification Masterlist File contains the EQ identifications for specific components. The staff reviewed the LRA, implementing procedure, and scoping reports to confirm 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 is adequate for identifying EQ SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(3).

Pressurized Thermal Shock. The staff confirmed that the applicant's scoping report described the use of UFSAR Section 5.3.3.6 to review the activities performed to meet 10 CFR 50.61, "PTS Rule," which resulted in the STP reactor pressure vessel being within the scope of license renewal pursuant to 10 CFR 54.4(a)(3). The staff reviewed the scoping report and determined that the methodology 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 in accordance with 10 CFR 54.4(a)(3).

Anticipated Transients without Scram. The staff determined that the applicant's scoping report, in regard to ATWS, included the plant systems credited for ATWS mitigation based on review of the ATWS topical report and the CLB, primarily UFSAR Section 7.8, "ATWS Mitigation System Activation Circuitry." The staff reviewed the LRA in conjunction with the scoping results to validate the methodology for identifying ATWS systems and structures that are within the scope of license renewal. The staff determined that the 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 including SSCs with functions credited for complying with the ATWS regulation within the scope of license renewal in accordance with 10 CFR 54.4(a)(3).

Station Blackout. The staff determined that the applicant's scoping results included SSCs identified in the CLB, which were associated with the plant's response to an SBO event. The staff reviewed the LRA in conjunction with the scoping results to validate the applicant's methodology. The staff finds that the scoping results included systems and structures that perform intended functions meeting 10 CFR 50.63 requirements. The staff determined that the applicant's scoping methodology was adequate for identifying SSCs credited in complying with the SBO regulation within the scope of license renewal in accordance with 10 CFR 54.4(a)(3).

2.1.4.3.3 Conclusion

Based on its reviews, the staff concludes that the applicant's methodology for identifying and including SSCs relied on to remain functional during regulated events is consistent with SRP-LR and 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 2.1.1, "Introduction," and its subsections, state, in part, the following:

> The scoping and screening steps have been performed in compliance with the requirements of 10 CFR [Part]54, and are consistent with the expectations set forth in the Statements of Consideration supporting the license renewal rule, and the guidance provided in NEI 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54—The License Renewal Rule."
>
> A variety of CLB documents were used to confirm or to determine additional SSC functions and evaluate them against the criteria of 10 CFR 54.4(a). Engineering drawings that provide layout and configuration details were reviewed for systems and structures. STP maintains a controlled master equipment database (MED) of design, configuration, and reference information for plant components and equipment, which are used in or support design, maintenance, surveillance, equipment clearance orders or work instruction activities. The master equipment database provides the design and quality classification for each component.

LRA Section 2.1.2, "Scoping Criteria," states, in part, that "SSCs that satisfy the criteria in 10 CFR 54.4(a)(1), (a)(2), or (a)(3) are within the scope of license renewal."

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 procedures. 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

Based on its review of the LRA, site guidance documents (including implementing procedures), 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; therefore, it is acceptable.

2.1.4.5 Mechanical Scoping

2.1.4.5.1 Summary of Technical Information in the Application

LRA Section 2.1.3.1 "Mechanical System Scoping Methodology," states, in part, the following:

> A list of mechanical systems was developed using the master equipment database and system plant numbering procedures and is documented in a technical position paper. A description was prepared for each mechanical system that included the purpose and summarized the functions that the system was designed to perform. This summary description was prepared using information obtained from the UFSAR system descriptions, CLB documents, design basis documents (including piping schematics), and system operating descriptions.
>
> System functions were compared against the criteria of 10 CFR 54.4(a)(1), (a)(2), and (a)(3). Each of the system functions satisfying the scoping criteria in 10 CFR 54.4(a) was identified as a system intended function. Any system that performed one or more intended functions (i.e., satisfying criterion (a)(1), (a)(2), or (a)(3)) was classified as a system within the scope of the license renewal rule. A review of CLB documentation was performed to identify all of its supporting systems that support the intended functions. License renewal boundary drawings were created for mechanical systems determined to be within the scope of license renewal. A component was determined to be in scope if that component was needed to fulfill a system intended function meeting the criteria of 10 CFR 54.4(a).

2.1.4.5.2 Staff Evaluation

The staff evaluated LRA Section 2.1.3.1 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 procedures 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 detailed 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 had appropriately applied the scoping methodology outlined in the LRA and implementing procedures and whether the scoping results were consistent with CLB requirements. The staff determined that the applicant's procedure was consistent with the description provided in LRA Section 2.1.3.1 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 reports for the AFW, essential chilled water/HVAC, ECW, emergency diesel generators systems, and the process used to identify mechanical components meeting the scoping criteria of 10 CFR 54.4. The staff reviewed the implementing procedures, confirmed that the applicant had identified and used pertinent engineering and licensing information, and discussed the methodology and results with the applicant. As part of the review process, the staff evaluated each system's identified intended functions, the basis for inclusion of the intended function, and the process used to identify each of the system component types. The staff confirmed that the applicant had identified and highlighted license renewal drawings to identify the license renewal boundaries in accordance with the implementing procedure guidance. Additionally, the staff determined that the applicant had independently confirmed the results in accordance with the implementing procedures. The staff confirmed that the applicant's license renewal personnel verifying the results were knowledgeable about the system and had performed independent reviews of the scoping reports and the applicable license renewal drawings to ensure accurate identification of the system intended functions. The staff confirmed that the systems identified by the applicant were evaluated against the criteria of 10 CFR 54.4(a)(1), (a)(2), and (a)(3). The staff confirmed that the applicant had used pertinent engineering and licensing information to determine that systems were included within the scope of license renewal in accordance with 10 CFR 54.4(a).

2.1.4.5.3 Conclusion

Based on its review, 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 2.1.3.2 "Structure Scoping Methodology," states, in part, the following:

> A list of structures was developed that included buildings, tank foundations, and other miscellaneous structures. The STP UFSAR was relied upon to identify the safety classifications of structures and structural components. Structure descriptions were prepared, including the structure purpose and functions. Structure evaluation boundaries were determined, including examination of structure interfaces. Structure functions were evaluated against the criteria of 10 CFR 54.4(a)(1), (a)(2), and (a)(3) and the results of this evaluation were documented. A license renewal site drawing was created for structures based on the site plan. For each in-scope structure, all of the structural components were evaluated and a determination was made as to whether the structural component was required to support the intended functions of the structure. Structural

components that support the intended functions of the structure were included within the scope of license renewal.

2.1.4.6.2 Staff Evaluation

The staff evaluated LRA Section 2.1.3.2, guidance in the implementing procedures, and reports to perform the review of the structural scoping process. The license renewal procedures 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 during the scoping and screening methodology audit. The staff determined that the applicant had identified and developed a list of plant structures and the structures' intended functions through a review of the UFSAR, plant equipment database, CLB documentation, documents, procedures, and drawings.

On a sampling basis, the staff reviewed the applicant's scoping reports for the turbine building and the process used to identify structural components that met the scoping criteria of 10 CFR 54.4. The staff reviewed the implementing procedures, confirmed that the applicant had identified and used pertinent engineering and licensing information, and discussed the methodology and results with the applicant. As part of the review process, the staff evaluated the turbine building's identified intended functions, the basis for inclusion of the intended function, and the process used to identify each of the structural component types. Additionally, the staff determined that the applicant had independently confirmed the results in accordance with the implementing procedures. The staff confirmed that the applicant's personnel verifying the results were knowledgeable about the system and had performed independent reviews of the scoping results and the applicable license renewal drawings to ensure accurate identification of structural intended functions. The staff confirmed that the structures identified by the applicant were evaluated against the criteria of 10 CFR 54.4(a)(1), (a)(2), and (a)(3). The staff confirmed that the applicant had used pertinent engineering and licensing information to determine that appropriate structures were included within the scope of license renewal in accordance with the 10 CFR 54.4(a).

2.1.4.6.3 Conclusion

Based on its review of information the LRA, the scoping implementation procedure, and structural scoping results, the staff concludes that the applicant's methodology for identification of the structures and structural components within the scope of license renewal is in accordance with the requirements of 10 CFR 54.4 and, therefore, is acceptable.

2.1.4.7 Electrical Component Scoping

2.1.4.7.1 Summary of Technical Information in the Application

LRA Section 2.1.3.3 "Electrical and I&C System Scoping Methodology," states, in part, the following:

> A list of electrical and I&C [instrumentation and controls] systems was developed and the systems were scoped against the criteria of 10 CFR 54.4(a). The UFSAR descriptions, database records, CLB documents and design basis

documents applicable to the system were reviewed to determine the system safety classification and to identify all of the system functions. System level functions were evaluated against the criteria of 10 CFR 54.4(a)(1), (a)(2) and (a)(3). The supporting systems needed to maintain the in-scope system intended functions were identified and evaluated against the criteria in 10 CFR 54.4(a)(2). Electrical and I&C components that perform an intended function as described in 10 CFR 54.4 for in-scope systems were included within the scope of license renewal.

2.1.4.7.2 Staff Evaluation

The staff evaluated LRA Section 2.1.3.3 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 identify 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 topical reports, the UFSAR, plant equipment database, CLB documentation, procedures, NEI 95-10, and the license renewal single line drawing.

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, and component level intended functions of the component types were identified (e.g., cable, connections, fuse holders, terminal blocks, high-voltage transmission conductor, connections and insulators, metal enclosed bus, and 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 had included electrical and I&C components and 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

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

2.1.4.8 Scoping Methodology Conclusion

Based on its review of information in the LRA, implementing procedures, and a sampling review of scoping results, the staff concludes that the applicant's scoping methodology is consistent with the guidance contained in the SRP-LR and identifies those SSCs that are within the scope of license renewal in accordance with 10 CFR 5.4(a)(1), (a)(2), and (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 2.1.4 “Screening Methodology,” states, in part, the following:

> The structures and components categorized as within the scope of license renewal were screened against the criteria of 10 CFR 54.21(a)(1)(i) and (1)(ii) to determine whether they are subject to AMR. 10 CFR 54.21 states that the structures and components subject to an AMR shall encompass those structures and components within the scope of the license renewal rule if they perform an intended function, as described in 10 CFR 54.4, without moving parts or without a change in configuration or properties; and are not subject to replacement based on a qualified life or specified time period. NEI 95-10 provides industry guidance for screening structures and components. The guidance provided in NEI 95-10, Appendix B, has been incorporated into the STP license renewal screening process.

2.1.5.1.2 Staff Evaluation

Pursuant to 10 CFR 54.21, each LRA must contain an IPA that identifies SCs within the scope of license renewal that are subject to an AMR. The IPA must identify components that perform an intended function without moving parts or a change in configuration or properties (passive), as well as components that are not subject to periodic replacement based on a qualified life or specified time period (long-lived).

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 are 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 2.1.4, the applicant discussed 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.” 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 the AFW, essential chilled water/HVAC, ECW, emergency diesel generators systems, 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. Specific methodology for mechanical, electrical, and structural component screening is discussed in SER Sections 2.1.5.2 through 2.1.5.4.

2.1.5.1.3 Conclusion

Based on its 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 2.1.4.1 "Mechanical System Component Screening Methodology," states, in part, the following:

> After a mechanical system component was categorized as in scope, the classification as an active or passive component was determined based on evaluation of the component description and type. The active/passive component determinations documented in NEI 95-10, Appendix B, provided guidance for this activity. In-scope components that were determined to be passive and long-lived were documented as subject to AMR.
>
> Each component that was identified as subject to an AMR was evaluated to determine its component intended function(s). The component intended function(s) was identified based on an evaluation of the component type and the way(s) in which the component supports the system intended functions. During the screening process, components that were identified as short-lived were eliminated from the AMR process and the basis for the classification as short-lived was documented. Other in-scope passive components were identified as subject to an AMR.

2.1.5.2.2 Staff Evaluation

The staff reviewed the mechanical screening methodology discussed and documented in LRA Section 2.1.4.1, the implementing procedures, the scoping and screening reports, and the license renewal drawings. The applicant had reviewed the system evaluation boundaries that had been identified by mapping the system intended function boundary onto the license renewal drawings. The staff confirmed that the applicant had identified the 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 applicant's review were documented in scoping and screening reports, which listed the information sources reviewed, the component intended functions, and the results of the review.

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 AFW, essential chilled water/HVAC, ECW, and emergency diesel generator systems to confirm proper implementation of the screening process.

The staff reviewed selected portions of the UFSAR, plant equipment database, CLB documentation, implementing procedures and reports, drawings, and selected scoping and screening reports. The staff conducted detailed discussions with the applicant's license renewal team and reviewed documentation pertinent to the screening process. The staff also performed a walkdown of portions of the selected systems with plant engineers to confirm 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. 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

Based on its review of information in 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 review of selected systems, 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 2.1.4.2 "Structural Component Screening Methodology," states, in part, the following:

> When a structure or structural component was determined to be in scope of license renewal by the scoping process described in [LRA] Section 2.1.3.2, the structure screening methodology classified the component as active or passive…During the structural screening process, the intended function(s) of passive structural components were documented and an evaluation was made to determine whether in-scope structural components were subject to replacement based on a qualified time period. If an in-scope structural component was determined to be subject to replacement based on a qualified time period, the component was identified as short-lived and was excluded from an AMR.

2.1.5.3.2 Staff Evaluation

The staff reviewed the structural screening methodology documented in LRA Section 2.1.4.2, the implementing procedure, and screening reports. The staff reviewed the applicant's 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 had reviewed the structures included within the scope of license renewal and identified the passive, long-lived components with component-level intended functions and determined those components to be subject to an AMR. The results of the applicant's review were documented in scoping and screening reports, which listed the information sources reviewed, the component intended functions, and the results of the review.

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 turbine building to confirm proper implementation of the screening process.

The staff reviewed selected portions of the UFSAR, plant equipment database, CLB documentation, implementing procedures and reports, drawings, and selected scoping and screening reports. The staff conducted detailed discussions with the applicant's license renewal team and reviewed documentation pertinent to the screening process. The staff also performed a walkdown of portions of the turbine building with plant engineers to confirm documentation. The staff assessed whether the structural screening methodology outlined in the LRA and procedures was appropriately implemented and if the scoping results were consistent with CLB requirements. Based on these audit activities, the staff did not identify any discrepancies between the methodology documented and the implementation results.

2.1.5.3.3 Conclusion

Based on its review of information in the LRA, implementing procedures, and 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 2.1.4.3 "Electrical and I&C Component Screening Methodology," states, in part, the following:

> The in-scope electrical components were categorized as "active" or "passive" based on the determinations documented in NEI 95-10, Appendix B. The screening of electrical and I&C components used the spaces approach which is consistent with the guidance in NEI 95-10. Use of the spaces approach for AMR of electrical component types eliminates the need to associate electrical and I&C components with specific systems that are within the scope of license renewal. The passive, long-lived electrical and I&C components that perform an intended function without moving parts or without change in configuration or properties were grouped into component types such as cable, connections, fuse holders, terminal blocks, high-voltage.

2.1.5.4.2 Staff Evaluation

The staff reviewed the applicant's methodology used for electrical component screening in LRA Section 2.1.4.3, "Electrical and I&C Component Screening Methodology," the applicant's implementing procedures, and reports. The staff confirmed that the applicant used the screening process described in these documents, along with the information contained in NEI 95-10 Appendix B and the SRP-LR, to identify the electrical and I&C components subject to an AMR.

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

The staff performed a sampling review to determine if the screening methodology outlined in the LRA and implementing procedures was appropriately implemented. During the scoping and screening methodology audit, the staff reviewed the electrical and I&C screening results and discussed the results with the applicant to confirm 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

Based on its review of information in the LRA, the screening implementation procedure, drawings, 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

Based on 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 is 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 August 23, 2011, and November 21, 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

LRA Section 2.1 describes the methodology for identifying systems and structures within the scope of license renewal and subject to an AMR. In LRA Section 2.2, the applicant used its scoping methodology to determine the plant-level systems and structures to be included within the scope of license renewal.

2.2.2 Summary of Technical Information in the Application

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

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

LRA Table 2.2-1 lists those mechanical systems, electrical and I&C systems, and structures that are within the scope of license renewal. LRA Table 2.2-1 also lists the systems and structures that do not meet the criteria specified in 10 CFR 54.4(a) and are excluded from the scope of license renewal. The applicant also provided a site drawing (LR-STP-STRUC-9Y100M00001) that showed the in-scope structures for license renewal in relation to one another.

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 documented its evaluation in SER Section 2.1. To confirm that the applicant properly implemented its methodology, the staff focused its review on the implementation results shown in LRA Table 2.2-1, "STP Scoping Results," 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 systems and structures that the applicant did not identify as within the scope of license renewal to confirm that the systems and structures do not 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."

In RAI 2.2-01, dated July 12, 2011, the staff noted that LRA Table 2.2-1 provides the results of applying the license renewal scoping criteria to the systems, structures, and commodities. The license renewal scoping criteria was described in Section 2.1. The following UFSAR system could not be located in LRA Table 2.2-1.

UFSAR Section	System
7.5.7 Emergency Response Facilities Data Acquisition and Display System (ERFDADS)	ERFDADS

RAI 2.2-01 requested the applicant to justify its exclusion of the above system in LRA Table 2.2-1.

In its response by letter dated August 9, 2011, the applicant stated that the Emergency Response Facilities Data Acquisition and Display System (ERFDADS) is a subsystem of the post-accident monitoring system, which is included in LRA Table 2.2-1 as being within the scope of license renewal.

Based on its review, the staff finds the applicant's response to RAI 2.2-01 acceptable because the applicant identified the EDFDADS as a subsystem of the post-accident monitoring system, which is included in LRA Table 2.2-1. Therefore, the staff's concern described in RAI 2.2-01 is resolved.

2.2.4 Conclusion

The staff reviewed LRA Section 2.2, the RAI response, and the UFSAR supporting information to determine whether the applicant properly identified all systems and structures relied on to mitigate DBEs, as required by 10 CFR 54.4(a)(1); systems and structures, the failure of which could prevent satisfactory accomplishment of any safety-related functions, as required by 10 CFR 54.4(a)(2); and 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). On the basis of its review, the staff concludes that the applicant 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 discusses the following items:

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

In accordance with the requirements of 10 CFR 54.21(a)(1), the applicant must list those passive, long-lived SCs that are within the scope of license renewal and that are subject to an AMR. To verify the applicant properly implemented its methodology, the staff focused its review 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, thus confirming that there were no omissions.

The staff's evaluation of mechanical systems was performed using the evaluation methodology described in SRP-LR Section 2.3 and took into account the system functions described in the UFSAR. The objective was to determine whether the applicant, in accordance with 10 CFR 54.4, has identified components and supporting structures for mechanical systems that meet the license renewal scoping criteria. Similarly, the staff evaluated the applicant's screening results to confirm 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 delineated in 10 CFR 54.4(a), the staff confirmed that the applicant properly screened out only (1) SCs that have functions performed with moving parts or that have a change in configuration or properties, or (2) 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 in order to resolve any omissions, issues, or discrepancies include an additional staff evaluation that specifically addresses the applicant's response to the RAI(s).

2.3.1 Reactor Vessel and Internals

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

- Section 2.3.1.1, "Reactor Vessel and Internals"
- Section 2.3.1.2, "Reactor Coolant System"
- Section 2.3.1.3, "Pressurizer"
- Section 2.3.1.4, "Steam Generators"
- Section 2.3.1.5, "Reactor Core"

2.3.1.1 Reactor Vessel, Internals, and Reactor Coolant System

2.3.1.1.1 Summary of Technical Information in the Application

LRA Section 2.3.1.1 states that the RV is a cylindrical shell with a welded, hemispherical lower head and a removable, bolted, flanged, and gasketed (O-ring) hemispherical upper head. The LRA states that the RV is supported by its nozzles and that it contains the core, core support structures, control rods, and other components associated with the core. The LRA also states that the reactor closure head has adaptors for the control rod drive mechanisms (CRDMs) for the head vent pipe. The hemispherical welded bottom head contains penetrations for in-core guide tubes, which extend from the seal table into the RV interior and provide the insertion and withdrawal path for the movable in-core thimble tubes.

Among the intended functions of the RV and RVI components within the scope of license renewal are the following:

- support the core and maintain fuel alignment
- direct coolant flow throughout the vessel
- serve as a reactor coolant pressure boundary
- 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 LRA states that there are no license renewal drawings providing details of RVI SSCs.

LRA Table 2.3.1-1 lists the component types that require an AMR.

2.3.1.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.1 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.1.1.3 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 concludes that the applicant appropriately identified the RV and internals system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.1.2 Reactor Coolant System

2.3.1.2.1 Summary of Technical Information in the Application

LRA Section 2.3.1.2 states that the RCS is located inside the containment building and consists of four reactor coolant heat transfer loops connected in parallel to the RV. The section also states that each loop consists of a reactor coolant pump, steam generator, and interconnecting piping and valves. Primary treated water is circulated through the core at a flow rate and temperature consistent with achieving the desired reactor core thermal-hydraulic performance. The LRA states that the pressurizer is connected to the RCS by a surge line to control RCS pressure and to accommodate volume changes of the coolant due to changes in temperature. The pressurizer is discussed in LRA Section 2.3.1.3.

The RCS provides a boundary for containing reactor coolant under all operating temperature and pressure conditions. It also serves to confine radioactive material and limits radioactive releases from the RCS to acceptable values, and it provides a means of venting non-condensable gases from system high points after an accident.

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

- serve as a pressure boundary for reactor coolant
- serve as a barrier to limit the release of radioactive products
- provide RCS pressure control and maintain temperature and pressure within limits under normal operations and anticipated transients
- provide containment isolation on its penetrations under design conditions

LRA Section 2.3.1.2 lists the UFSAR sections with additional details and the license renewal drawings that provide more information on SSCs within the scope of license renewal and subject to an AMR.

LRA Table 2.3.1-2 lists the component types that require an AMR.

2.3.1.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.2 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.1.2.3 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 concludes that the applicant appropriately identified the RCS mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.1.3 Pressurizer

2.3.1.3.1 Summary of Technical Information in the Application

LRA Section 2.3.1.3 states that the pressurizer is connected to the RCS and provides pressure control by maintaining an interface of saturated liquid and vapor coolant in an equilibrium pressure and temperature relationship under normal and anticipated transient conditions. By allowing liquid insurges and outsurges through the pressurizer surge line, and allowing spray flow from two RCS legs or pressurizer heating from the pressurizer heaters, RCS pressure is controlled to within operational limits. The LRA also states that additional over-pressure control is provided by the pressurizer power-operated relief valves.

The LRA states that the pressurizer is a vertical cylindrical pressure tank constructed of carbon steel and clad with austenitic stainless steel on the inside of the vessel. The LRA also states that the pressurizer has "essentially hemispherical top and bottom heads," which are also carbon steel clad with austenitic stainless steel on inner surfaces. Finally, the LRA states that the surge line (with an internal thermal sleeve) and the electric heaters are installed on the bottom head and that spray line nozzles, relief valve connections, and code safety valves are connected through the upper head.

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

- serve as a pressure boundary for reactor coolant
- provide code safety valves for over-pressure protection
- maintain RCS pressure by allowing combinations of insurges, outsurges, spray flow, and heater operation
- provide support for fire protection and SBO response

LRA Section 2.3.1.3 lists the UFSAR sections with additional details on SSCs within the scope of license renewal and subject to an AMR.

LRA Table 2.3.1-3 lists the component types that require an AMR.

2.3.1.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.3 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.1.3.3 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 concludes that the applicant appropriately identified the pressurizer system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.1.4 Steam Generators

2.3.1.4.1 Summary of Technical Information in the Application

LRA Section 2.3.1.4 states that the four steam generators (one steam generator for each RCS loop) generate steam and provide heat removal for normal operations, transients, DBEs, SBO events, and fire protection safe shutdown scenarios. The LRA also states that the steam generators provide the steam source for the turbine driven AFW pump.

The steam generators are shell and U-tube vertical heat exchangers, with a primary section (primary channel head) to guide reactor coolant through the steam generator U-tubes and a secondary section for generating steam. The LRA states that the primary channel head and the U-tubes are part of the reactor coolant pressure boundary, and the steam generators form a part of the containment pressure boundary to prevent the release of fission products to the environment. The applicant stated that the steam generators are within the scope of license renewal based upon criteria of 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

The applicant also stated that UFSAR Sections 5.1, 5.2, 5.4.2, and 10.4.9 provided additional details of the steam generators. Finally, the applicant stated that the LRA contains no license renewal boundary drawings for the steam generators.

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

- transfer heat from the RCS to the secondary systems for normal operations, DBEs, SBO, and fire protection safe shutdown situations
- provide RCS pressure boundary functions
- form part of the containment boundary for preventing fission product release
- perform other functions related to SBO and fire protection safe shutdown events

LRA Table 2.3.1-4 lists the component types that require an AMR.

2.3.1.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.4 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.1.4.3 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 concludes that the applicant appropriately identified the steam generator mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.1.5 Reactor Core

2.3.1.5.1 Summary of Technical Information in the Application

LRA Section 2.3.1.5 states that the reactor core system contains and supports the fuel assemblies and control rods. The LRA states that the core contains 193 fuel assemblies, which help to direct flow through the core and restrict bypass flow in order to meet heat transfer requirements during operation. The LRA also states that the fuel assemblies have provisions for guiding control rod movements and for holding fixed neutron absorber rods to achieve reactivity control in conjunction with the soluble boron in the reactor coolant. The LRA also states that the fuel cladding provides one of the primary fission product barriers. Finally, the LRA states that the fuel assemblies and rod control cluster assemblies (RCCAs) are considered as short-lived components since they are replaced at regular intervals based on fuel cycle schedules and refueling operations. Therefore, the LRA concludes that, while the reactor core system is within the scope of license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(3), it contains no components subject to an AMR.

The LRA lists UFSAR Sections 4.1 and 4.2 as providing additional details concerning the reactor core. The LRA also states that there are no license renewal boundary drawings for the reactor core.

2.3.1.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.5 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.1.5.3 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 concludes that the applicant appropriately identified the reactor core mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the system components as short-lived not subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2 Engineered Safety Features

LRA Section 2.3.2 describes the engineered safety features (ESF) systems, along with their SCs, subject to an AMR for license renewal. The applicant described the supporting SCs of the ESF system in the following LRA sections:

- Section 2.3.2.1, "Containment Spray System"
- Section 2.3.2.2, "Integrated Leak Rate Test System"
- Section 2.3.2.3, "Residual Heat Removal System"
- Section 2.3.2.4, "Safety Injection System"

2.3.2.1 Containment Spray

2.3.2.1.1 Summary of Technical Information in the Application

LRA Section 2.3.2.1 describes the containment spray system as being designed to perform various functions following a DBA:

- maintain containment pressure below its design limit
- scrub fission products from the containment atmosphere
- establish containment sump pH to retain elemental iodine in the sump
- limit post-accident offsite radiation doses

The system is described as having containment spray pumps, spray ring headers, spray nozzles, spray additive educators for blending in trisodium phosphate (TSP), TSP baskets, and associated valves and piping.

The LRA states that the containment spray system is within the scope of license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(2). The section also states that additional details are presented in UFSAR Sections 3.11.5, 6.1.1.2, 6.2.2, 6.2.4, and 6.5.2; finally, the LRA lists the license renewal boundary drawings for this system.

LRA Table 2.3.2-1 identifies the component types subject to an AMR for the containment spray system.

2.3.2.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.1 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.2.1.3 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 concludes that the applicant appropriately identified the containment spray system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2.2 Integrated Leak Rate Test System

2.3.2.2.1 Summary of Technical Information in the Application

LRA Section 2.3.2.2 describes the purpose of the integrated leak rate test (ILRT) system as providing the ability to conduct periodic testing of containment leakage by pressurizing containment and monitoring any subsequent leakage to the atmosphere. The LRA states that the system is comprised of blank flanges, piping, and drain valves.

The LRA also states that the system is within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), and some portions of the system are within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

The LRA states that UFSAR Sections 6.2.4 and 6.2.6 contain additional details on the ILRT system. Finally, LRA Section 2.3.2.2 lists license renewal boundary drawings for this system.

LRA Table 2.3.2-2 identifies the component types subject to an AMR for the ILRT system.

2.3.2.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.2 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.2.2.3 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 concludes that the applicant appropriately identified the ILRT system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2.3 Residual Heat Removal System

2.3.2.3.1 Summary of Technical Information in the Application

LRA Section 2.3.2.3 describes the residual heat removal (RHR) system and states that it is designed to do the following:

- transfer decay heat out of the RCS and into the component cooling water (CCW) system
- remove decay heat and maintain proper temperatures in the RCS during cold shutdown and refueling
- provide RCS pressure control during plant startups and cooldowns
- provide functions of safety injection during injection and recirculation phases of loss-of-coolant accidents (LOCAs)
- transfer refueling water between the refueling cavity and the refueling water storage tank (RWST)

The LRA states that the RHR system is within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

LRA Table 2.3.2-3 lists the component types subject to an AMR for the RHR system.

2.3.2.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.3 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.2.3.3 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 concludes that the applicant appropriately identified the RHR system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2.4 Safety Injection System

2.3.2.4.1 Summary of Technical Information in the Application

LRA Section 2.3.2.4 describes the safety injection system. The LRA states that it has the following purposes:

- remove decay heat from the reactor core and provide shutdown capability during accident conditions
- inject borated water into the RCS from accumulators and from the RWST, depending on RCS pressure, during an accident
- provide recirculating coolant from the containment sump through the safety injection pumps to the RCS

The LRA also states that the system is comprised of three injection subsystems, the RWST, and emergency containment sumps and associated strainers. Each injection subsystem has a high head pump, a low head pump, an accumulator, and associated piping and valves.

The LRA states that the safety injection system is within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

LRA Table 2.3.2-4 lists the component types subject to an AMR for the safety injection system.

2.3.2.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.4 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.2.4.3 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 concludes that the applicant has appropriately identified the safety injection system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3 Auxiliary Systems

LRA Section 2.3.3 identifies the auxiliary 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, "Fuel Handling"
- Section 2.3.3.2, "Spent Fuel Pool Cooling and Cleanup"
- Section 2.3.3.3, "Cranes and Hoists"
- Section 2.3.3.4, "Essential Cooling Water [ECW] and ECW Screenwash"
- Section 2.3.3.5, "Reactor Makeup Water"
- Section 2.3.3.6, "Component Cooling Water"
- Section 2.3.3.7, "Compressed Air"
- Section 2.3.3.8, "Primary Process Sampling"
- Section 2.3.3.9, "Chilled Water HVAC [Heating Ventilation and Air Conditioning]"
- Section 2.3.3.10, "Electrical Auxiliary Building and Control Room HVAC"
- Section 2.3.3.11, "Fuel Handling Building HVAC"
- Section 2.3.3.12, "Mechanical Auxiliary Building HVAC"
- Section 2.3.3.13, "Miscellaneous HVAC (In Scope)"
- Section 2.3.3.14, "Reactor Containment Building HVAC"
- Section 2.3.3.15, "Standby Diesel Generator Building HVAC"
- Section 2.3.3.16, "Containment Hydrogen Monitoring and Combustible Gas Control"
- Section 2.3.3.17, "Fire Protection"
- Section 2.3.3.18, "Standby Diesel Generator Fuel Oil Storage and Transfer"
- Section 2.3.3.19, "Chemical and Volume Control"
- Section 2.3.3.20, "Standby Diesel Generator and Auxiliaries"
- Section 2.3.3.21, "Nonsafety-Related Diesel Generators and Auxiliary Fuel Oil"
- Section 2.3.3.22, "Liquid Waste Processing"
- Section 2.3.3.23, "Radioactive Vents and Drains"
- Section 2.3.3.24, "Nonradioactive Waste Plumbing Drains and Sumps"
- Section 2.3.3.25, "Oily Waste"
- Section 2.3.3.26, "Radiation Monitoring (Area and Process) Mechanical"
- Section 2.3.3.27, "Miscellaneous Systems In-Scope Only for Criterion a(2)"
- Section 2.3.3.28, "Lighting Diesel Generator System"

<u>Auxiliary Systems Generic Requests for Additional Information</u>. In RAI 2.3-1, dated July 12, 2011, the staff noted six instances on drawings where the staff was unable to identify the license renewal boundary because continuations among drawings were not provided or were incorrect. The staff requested that the applicant provide additional information that would enable the staff to locate and understand the continuations among drawings.

In its response dated August 9, 2011, the applicant provided information to clarify the extent of the license renewal boundary for each of the six continuations. In each case, the applicant detailed the routing and location of the piping in question. The applicant also clarified one item, in which the 4"WL1165WG7 piping was depicted within scope of license renewal for 10 CFR 54.4(a)(2) on license renewal drawing LR-STP-OC-6T249F00033#1, but was incorrectly depicted as excluded from scope of license renewal on the continuation license renewal drawing LR-STP-WL7R309F90001#1. By letter dated November 3, 2011, the applicant revised license renewal drawing LR-STP-WL7R309F90001#1 to depict the 4"WL1165WG7 piping and associated valves as being within the scope of license renewal for 10 CFR 54.4(a)(2).

Based on its review, the staff finds the applicant's response to RAI 2.3-1 acceptable because the applicant provided additional information that identified the license renewal boundaries, and, in all cases, the extent of the license renewal boundary was determined in accordance with the requirements of the scoping and screening methodology. No new component types were identified as a result of the response to the RAI. Several additional valves were identified as in the scope of license renewal as the RAI resolution. Therefore, the staff's concern described in RAI 2.3-1 is resolved.

2.3.3.1 Fuel Handling

2.3.3.1.1 Summary of Technical Information in the Application

LRA Section 2.3.3.1 states that the fuel handling system is designed to provide safe handling of reactor fuel, and it has provisions for storing both spent fuel and new fuel onsite in a subcritical arrangement, maintaining subcriticality under design operating and accident conditions. The section states that the system does the following:

- contains equipment and structures for carrying loads over safety-related components and over irradiated fuel assemblies
- has both new fuel storage and spent fuel storage racks and associated equipment for lifting, transporting, operating on, and handling fuel assemblies, as well as tools for changing out RCCAs and other components inserted into the fuel assemblies
- contains the refueling transfer tube, penetration tube, and the refueling transfer tube expansion bellows

The LRA also notes that the penetration expansion bellows is evaluated as part of the containment structure.

The LRA states that, since the fuel handling system provides structural support for safe, subcritical storage of fuel assemblies and is part of the containment integrity when the blank flange is installed on the transfer tube, this system is within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). Finally, since the system has nonsafety-related components that could affect safety-related components, the LRA states that the fuel handling system is also within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

LRA Table 2.3.3-1 identifies the fuel handling system component types subject to an AMR.

2.3.3.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.1 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.1.3 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 concludes that the applicant appropriately identified the fuel handling system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.2 Spent Fuel Pool Cooling and Cleanup

2.3.3.2.1 Summary of Technical Information in the Application

LRA Section 2.3.3.2 discusses the spent fuel cooling and cleanup system and describes it as containing the following: (a) two fuel pool cooling loops, associated pumps, heat exchangers, and valves; and (b) a two-loop purification subsystem that has pumps, filters, piping, valves, and a fuel pool surface skimmer loop and components. The LRA states that the system's functions are as follows:

- to remove decay heat from the spent fuel assemblies located in the spent fuel pool
- to purify the cooling water in order to maintain optical clarity for the spent fuel pool and the refueling cavity
- to maintain fuel pool temperature below prescribed limits
- to maintain water inventory over the spent fuel assemblies to limit radiation exposures and radiological consequences following a design basis fuel handling accident

Finally, the LRA states that the system has piping that penetrates containment and associated penetration isolation valves.

The LRA states that the spent fuel pool cooling and cleanup system is within the scope of license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(2).

LRA Table 2.3.3-2 identifies the spent fuel cooling and cleanup system component types subject to an AMR.

2.3.3.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.2 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.2.3 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 concludes that the applicant appropriately identified the spent fuel pool cooling and cleanup system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.3 Cranes and Hoists

2.3.3.3.1 Summary of Technical Information in the Application

LRA Section 2.3.3.3 describes the cranes and hoists system. The LRA states that this system contains 10 sets of cranes and hoists, among which are the reactor building polar crane, the cask handling overhead (150-ton) crane, various fuel handling cranes, and the diesel generator overhead cranes. The section states that the purpose of the cranes and hoists is to provide lifting and component handling capabilities in the reactor building, the MAB, the FHB, and other various locations.

The LRA states that the cranes and hoists system is within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

LRA Table 2.3.3-3 contains a list of the component types subject to an AMR for the cranes and hoists system.

2.3.3.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.3 and UFSAR Section 9.1.4.3 using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results.

In RAI 2.3.3.1-1, dated July 12, 2011, the staff noted that UFSAR Section 3.8.4.1.1, "Mechanical-Electrical Auxiliaries Building (MEAB)," states that the 7.5-ton overhead bridge crane necessary for handling radioactive solid waste is not within the scope of license renewal. This crane is located in the MEAB, which is in-scope for 10 CFR 54.4(a)(1), (a)(2), and (a)(3). The staff requested that the applicant provide the basis for not including the MEAB 7.5-ton overhead bridge crane within the scope of license renewal.

In its response dated August 9, 2011, the applicant stated that the solid waste processing 7.5-ton gantry cranes are not seismic II/I components and are not within the scope of license renewal. The applicant also stated that the 7.5-ton gantry cranes do not carry heavy loads over safety-related components, irradiated fuel in the RV, or the spent fuel pool.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.3-1, and the classification of the components as not within the scope of license renewal, acceptable because the applicant explained that the 7.5-ton gantry cranes are not seismic II/I components and are in an area of the MEAB that does not contain safety-related components or irradiated fuel in their load path. Therefore, the staff's concern described in RAI 2.3.3.3-1 is resolved.

2.3.3.3.3 Conclusion

The staff reviewed the LRA, UFSAR, 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 identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the cranes and hoists system mechanical components within the scope of license renewal, as required by 10 CFR 54.5(a), and that the applicant adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.4 Essential Cooling Water and ECW Screenwash

2.3.3.4.1 Summary of Technical Information in the Application

LRA Section 2.3.3.4 discusses the ECW and ECW screenwash system. The LRA states that the ECW portion is comprised of three redundant cooling loops, each of which has a pump, a CCW heat exchanger, a set of diesel generator heat exchangers, and other heat exchangers, piping, and valves. The LRA states that the ECW screenwash portion contains traveling screens, screenwash pumps, strainers, piping, and valves. The section also describes the purposes of the ECW and ECW screenwash system as follows: (a) to remove heat from safety-related components and transfer that heat to the ultimate heat sink; and (b) to provide a means to wash the traveling screens on the suction part of the system in order to prevent the ECW pumps from losing suction.

The LRA states that several of the major ECW cooling loop heat exchangers are evaluated along with the respective systems being cooled by the ECW and ECW screenwash system, and that the essential cooling pond (the ultimate heat sink) is evaluated with the ECW structures.

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

LRA Table 2.3.3-4 contains a list of the component types subject to an AMR for the ECW and ECW screenwash system.

2.3.3.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.4, UFSAR Sections 1.2.2.4.2 and 9.2.1.2, and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs, as discussed below.

In RAI 2.3.3.4-1, dated July 12, 2011, the staff noted that on license renewal boundary drawings LR-STP-EW-5R289F05038#1-1 and LR-STP-EW-5R289F05038#1-2 and LR-STP-EW-5R289F05038#2-1, LR-STP-EW-5R289F05038#2-2, and LR-STP-EW-5R289F05038#2-3, coordinates C-4, a section of 6"EW1122WF7 piping to the ECW discharge structure was depicted as not being within the scope of license renewal. However, LR-STP-EW-5R289F05038 #1-3, coordinates C-4, depicts this section of 6"EW1122WF7 piping to the ECW discharge structure as being within the scope of license renewal for 10 CFR 54.4(a)(2). The staff requested that the applicant provide the basis for the differences in the scoping designation of the piping downstream of the termination symbol within the scope of license renewal.

In its response dated August 9, 2011, the applicant stated that, on license renewal drawing LR-STP-EW-5R289F05038#1-3, the 6"EW1122WF7 piping section from the “F.4.e” termination symbol to the ECW discharge structure is not within the scope of license renewal, and that the 10 CFR 54.4(a)(2) highlighting should stop at the “F.4.e” termination symbol. By letter dated November 3, 2011, the applicant revised the license renewal boundary drawing LR-STP-EW-5R289F05038#1-3 to correct the discrepancy in the scoping boundary related to the 6"EW1122WF7 piping.

Based on its review, the staff finds the applicant’s response to RAI 2.3.3.4-1 acceptable because the applicant corrected the discrepancy in the scoping boundary of the 6"EW1122WF7 piping and revised the license renewal drawing to show that the in-scope classification terminates at the point where the underground portion ends. Therefore, the staff’s concern described in RAI 2.3.3.4-1 is resolved.

In RAI 2.3.3.4-02, dated July 12, 2011, the staff noted on license renewal drawing LR-STP-EW-5R289F05038#2-1, coordinates E-4, a section of 10 CFR 54.4(a)(1) 4"EW2126WD8 piping continued to LR-STP-DR-F20005#2, coordinates F-6, where it is shown within scope of license renewal for 10 CFR 54.4(a)(2). The staff requested that the applicant provide the basis for the scoping classification change from 10 CFR 54.4(a)(1) to 10 CFR 54.4(a)(2).

In its response dated August 9, 2011, the applicant stated that license renewal drawing LR-STP-EW-5R289F05038#2-1 indicates a safety-related to nonsafety-related interface at valve FV6935 and incorrectly depicts the nonsafety-related portion of the piping as being within the scope of license renewal for 10 CFR 54.4(a)(1). The applicant stated that license renewal drawing LR-STP-DR-6Q069F20005#2 depicts a spatial interaction termination symbol, which should be an “F.4.1” triangle symbol. By letter dated November 3, 2011, the applicant revised license renewal boundary drawings LR-STP-EW-5R289F05038#2-1 and LR-STP-DR-6Q069F20005#2 to indicate the correct (10 CFR 54.4(a)(2) due to spatial interaction) scoping designation for the 4"EW2126WD8 piping past the interface at valve FV6935 and inserted the correct termination symbol for structural integrity.

Based on its review, the staff finds the applicant’s response to RAI 2.3.3.4-02, and the corrections to the scoping boundary, acceptable because the applicant corrected the associated license renewal boundary drawings to show the safety-related to nonsafety-related transition past interface valve FV6935 and to show a consistent classification for the 4"EW2126WD8 piping past that valve. Therefore, the staff’s concern described in RAI 2.3.3.4-02 is resolved.

In RAI 2.3.3.4-3, dated July 12, 2011, the staff noted on LRA drawing LR-STP-EW-5R289F05038#1-3, coordinates C-4, that piping section 6"EW1322WF7 into the ECW discharge structure was depicted in-scope of license renewal for 10 CFR 54.4(a)(2) beyond the “F.4.e” termination symbol (which is the symbol to terminate this 10 CFR 54.4(a)(2) scoping boundary). The 10 CFR 54.4(a)(2) license renewal boundaries for similar piping sections 6"EW1122WF7 and 6"EW1222WF7 on drawings LR-STP-EW-5R289F05038#1-1 and LR-STP-EW-5R289F05038#1-2, coordinates C-4, respectively, end at the “F.4.e” termination symbols. The staff requested that the applicant provide the basis for indicating the 6"EW1322WF7 piping within scope of license renewal for 10 CFR 54.4(a)(2) beyond the termination symbol on license renewal drawing LR-STP-EW-5R289F05038#1-3.

In its response dated August 9, 2011, the applicant stated that on license renewal drawing LR-STP-EW-5R289F05038#1-3, the red (10 CFR 54.4(a)(2)) highlighting should stop at the "F.4.e" termination symbol. By letter dated November 3, 2011, the applicant revised license renewal drawing LR-STP-EW-5R289F05038#1-3 to remove the 10 CFR 54.4(a)(2) highlighting on the 6"EW1322WF7 piping downstream of the "F.4.e" termination symbol.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.4-3, and the corrections to the scoping boundary, acceptable because the applicant corrected the inconsistent scoping boundary for the 6"EW1322WF7 piping section and revised the associated license renewal drawing to be consistent with the designation of 10 CFR 54.4(a)(2) scoping boundaries. Therefore, the staff's concern described in RAI 2.3.3.4-03 is resolved.

2.3.3.4.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and license renewal boundary drawings (original and revised) 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 identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the ECW and ECW screen wash system mechanical components within the scope of license renewal, as required by 10 CFR 54.5(a), and that the applicant adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.5 Reactor Makeup Water

2.3.3.5.1 Summary of Technical Information in the Application

LRA Section 2.3.3.5 describes the reactor makeup water system and states that it is comprised of a storage tank, two transfer pumps, piping, and valves. The section states that the system's purpose is to provide reactor grade makeup water to the RCS and other systems or components via several connections—the chemical and volume control system (CVCS), the spent fuel cooling system, the CCW surge tank, the boron recycle system, and the pressurizer relief tank (PRT).

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(2).

LRA Table 2.3.3-5 contains a list of the component types subject to an AMR for the reactor makeup water system.

2.3.3.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.5, UFSAR Section 9.2.7, and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs, as discussed below.

In RAI 2.3.3.5-1, dated July 12, 2011, the staff noted on license renewal boundary drawings LR-STP-RM-5R279F05033#1 and LR-STP-RM-5R279F05033#2, coordinates G-4, a floating seal of the reactor makeup water storage tanks 1A and 1B as not being within the scope of license renewal. LRA Table 2.3.3-5 does not list this floating seal. This component appears to be part of the reactor makeup water system, which is depicted as being within the scope of license renewal for 10 CFR 54.4(a)(1). The staff requested that the applicant provide the basis for excluding the floating seal from the scope of license renewal.

In its response dated August 9, 2011, the applicant stated that the floating seals shown on drawings LR-STP-RM-5R279F05033#1 and LR-STP-RM-5R279F05033#2 are not safety-related and do not perform any safety function, but they are within the scope of license renewal for nonsafety affecting safety pursuant to 10 CFR 54.4(a)(2) and were inadvertently not highlighted. The applicant described the floating seals as having the nonsafety-related function of controlling oxygen levels in the makeup water and stated that the seals are replaced when the dissolved oxygen level is exceeded. The applicant determined that these seals are short-lived components and, therefore, do not require an AMR. The applicant also revised license renewal boundary drawings LR-STP-RM-5R279F05033#1 and LR-STP-RM-5R279F05033#2 to depict the seals as being within the scope of license renewal for 10 CFR 54.4(a)(2).

Based on its review, the staff found the response to RAI 2.3.3.5-1 unacceptable because the applicant did not discuss whether the floating seals were replaced due to a vendor-specified qualified life or specific time period, as required by 10 CFR 54.21(a)(1)(ii). SRP-LR Section 2.1.1 states, in part, that "SCCs subject to an AMR are those that… are not subject to replacement based on a qualified life or specified time period…" In addition, NEI 95-10 (which is endorsed by RG 1.188, Revision 1) states, in part, that "…[r]eplacement programs may be based on vendor recommendations, plant experience, or any means that establishes a specific service life, qualified life or replacement frequency under a controlled program." Although the applicant stated in its RAI response that plant operating experience has demonstrated that the dissolved oxygen level can be used as a replacement indicator for the seals, the applicant did not document a specific service life, qualified life, or actual replacement frequency for the seals as part of its basis for excluding them from an AMR. The staff issued followup RAI SBPB-2-2, dated November 15, 2011, to request that the applicant either reconsider its position on the floating seals being excluded from AMR or provide an adequate basis for replacement that complies with 10 CFR 54.21(a)(1)(ii).

In its response dated December 15, 2011, the applicant revised its position on the floating seals and included aging management provisions for them as part of its Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP. In addition to its response, the applicant revised LRA Table 2.3.3-5, Table 3.3.2-5, LRA Appendix A1.22, LRA Appendix B2.1.22, LRA Basis Document XI.M38, and LRA Section 3.3.2.1.5 to include the floating seals. Based on its review, the staff finds the applicant's response to RAI SBPB-02-02, and the inclusion of aging management provisions for the floating seals into an appropriate AMP, acceptable because the applicant revised the seals' classification and aging management to be consistent with SRP-LR Section 2.1.1, included the floating seals in an appropriate AMP, and revised the LRA accordingly. Therefore, the staff's concerns described in RAIs 2.3.3.5-1 and SBPB-2-2 are resolved.

In RAI 2.3.3.5-2, dated July 12, 2011, the staff noted on license renewal boundary drawings LR-STP-RM-5R279F05033#1 and LR-STP-RM-5R279F05033#2, coordinates G-7, the omission of seismic anchors on the 10 CFR 54.4(a)(2) nonsafety-related piping connected to safety-related piping downstream of valve FV7664. The staff requested that the applicant provide the location of the seismic anchors.

In its response dated August 9, 2011, the applicant stated that the nonsafety-related piping in question is connected to the primary sample panel (ZLP131), which is credited as an equivalent anchor and designated with the “F.4.3” symbol for equivalent anchor on continuation drawings LR-STP-PS-9Z329Z00047#1 and LR-STP-PS-9Z329Z00047#2.

Based on its review, the staff finds the applicant’s response to RAI 2.3.3.5-2, and the designation of the sample panel as the seismic anchor, acceptable because the applicant identified the location of the seismic anchor on the nonsafety-related piping downstream of valve FV7664. Therefore, the staff’s concern described in RAI 2.3.3.5-2 is resolved.

2.3.3.5.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and license renewal boundary drawings (original and revised) 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 identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the reactor water makeup system mechanical components within the scope of license renewal, as required by 10 CFR 54.5(a), and that the applicant adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.6 Component Cooling Water

2.3.3.6.1 Summary of Technical Information in the Application

LRA Section 2.3.3.6 describes the CCW system and states that it consists of three 50-percent capacity cooling loops containing pumps, heat exchangers, associated piping and valves, and one system surge tank. The LRA states that the purposes of the system are as follows:

- to function as an isolation system between radioactive heat sources and the ECW system to minimize the potential for radioactive leaks or contamination to the environment
- to provide continuous cooling to those components during normal operations
- to provide cooling to remove residual heat from the reactor during normal shutdowns
- to provide cooling to the spent fuel pool
- to cool certain ESF loads during design basis events

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(2), (a)(2), and (a)(3).

LRA Table 2.3.3-6 contains a list of the component types subject to an AMR for the CCW system.

2.3.3.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.6, UFSAR Section 9.2.2, and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff’s review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs, as discussed below.

In RAI 2.3.3.6-1, dated July 12, 2011, the staff noted on license renewal boundary drawings LR-STP-CC-5R209F05017#1 and LR-STP-CC-5R209F05017#2, coordinates G-6, short pipe extensions connected to valve CC0746 that are within the scope of license renewal for 10 CFR 54.4(a)(2). The short pipe extensions have no identification, anchor, or boundary location established. The staff requested that the applicant provide the identification, anchor, or boundary location for these pipe section extensions.

In its response dated August 9, 2011, the applicant clarified that the short pipe extensions are free end 6-inch stubs of pipe and are correctly shown on the license renewal boundary drawings as being within the scope of license renewal pursuant to 10 CFR 54.4(a)(2) for spatial interaction and structural integrity attached (i.e., they are termination points for nonsafety-related SSCs attached to safety-related SSCs, included to provide structural integrity). The applicant also confirmed this by referring to isometric drawings of the piping in question.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.6-1, and the explanation of the scoping boundaries, acceptable because the applicant confirmed by isometric drawings that these are free end 6-inch stubs of pipe that are within the scope of license renewal for 10 CFR 54.4(a)(2). Therefore, the staff's concern described in RAI 2.3.3.6-1 is resolved.

In RAI 2.3.3.6-2, dated July 12, 2011, the staff noted that license renewal boundary drawings LR-STP-CC-5R209F05020#1 and LR-STP-CC-5R209F05020#2, coordinates E-1, depict pipe sections 1"CC1647XC7 and 1"CC2647XC7 as being within the scope of license renewal pursuant to 10 CFR 54.4(a)(2), and they continue to license renewal boundary drawings LR-STP-SB-5S209F20002#1 and LR-STP-SB-5S209F20002#2, coordinates D-4, where they are shown as not within the scope of license renewal. The staff requested that the applicant provide a basis for not including the pipe sections on license renewal boundary drawings LR-STP-SB-5S209F20002#1 and LR-STP-SB-5S209F20002#2 within the scope of license renewal.

In its response dated August 9, 2011, the applicant stated that the 1"CC1647XC7 and 1"CC2647XC7 pipe sections are correctly depicted within the scope of license renewal on license renewal boundary drawings LR-STP-CC-5R209F05020#1 and LR-STP-CC-5R209F05020#2. The applicant also stated that the spatial interaction termination symbols were inadvertently omitted from the license renewal boundary drawings LR-STP-CC-5R209F05020#1 and LR-STP-CC-5R209F05020#2, which indicate that the pipe sections' scoping boundaries for spatial interaction terminate once they exit the areas with the safety-related components. By letter dated November 3, 2011, the applicant revised license renewal boundary drawings LR-STP-CC-5R209F05020#1 and LR-STP-CC-5R209F05020#2 to include the spatial interaction termination symbols.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.6-2, and the corrections to the scoping boundary, acceptable because the applicant corrected the missing spatial interaction scoping boundary symbols for pipe sections 1"CC1647XC7 and 1"CC2647XC7 and revised license renewal boundary drawings LR-STP-CC-5R209F05020#1 and LR-STP-CC-5R209F05020#2 by adding those termination symbols before the off-sheet connectors. Therefore, the staff's concern described in RAI 2.3.3.6-2 is resolved.

In RAI 2.3.3.6-3, dated July 12, 2011, the staff noted on license renewal boundary drawings LR-STP-CC-5R209F05020#1 and LR-STP-CC-5R209F05020#2, coordinates B-1, 10 CFR 54.4(a)(2) pipe sections 1"CC1649XC7 and 1"CC2649XC7 continued from license renewal boundary drawings LR-STP-SB-5S2099F20002#1 and LR-STP-SB-5S2099F20002#2, coordinates D-4, where they are shown as not being within the scope of license renewal. The staff requested that the applicant provide the basis for not including the pipe sections within the scope of license renewal on license renewal boundary drawings LR-STP-SB-5S2099F20002#1 and LR-STP-SB-5S2099F20002#2.

In its response dated August 9, 2011, the applicant stated that it would revise license renewal boundary drawings LR-STP-CC-5R209F05020#1 and LR-STP-CC-5R209F05020#2 to add spatial interaction termination symbols on pipe sections 1"CC1647XC7 and 1"CC2647XC7 before continuing to the next drawing because the piping leaves the area of safety-related components at those points. The applicant provided the revised license renewal boundary drawings to the staff by letter dated November 3, 2011.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.6-3, and the corrections to the scoping boundary, acceptable because the applicant explained that the piping leaves the safety-related areas; the applicant corrected the license renewal boundary drawings by adding spatial interaction termination symbols before pipe sections 1"CC1647XC7 and 1"CC2647XC7 continue to the next drawing. The staff finds the 10 CFR 54.4(a)(2) spatial interaction boundaries to be acceptable. Therefore, the staff's concern described in RAI 2.3.3.6-3 is resolved.

2.3.3.6.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and license renewal boundary drawings (original and revised) 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 identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the CCW system mechanical components within the scope of license renewal, as required by 10 CFR 54.5(a), and that the applicant adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.7 Compressed Air

2.3.3.7.1 Summary of Technical Information in the Application

LRA Section 2.3.3.7 describes the compressed air system. The section states that it consists of portions of four air systems—the instrument air system, the service air system, the breathing air system, and the personnel air lock seal air system. The LRA states that its purpose is to provide dry, filtered, oil-free, compressed air to these four systems for use in pneumatic actuators, breathing air, sealing for the personnel airlock, and various other services requiring compressed air. The LRA also states that the system is comprised of air compressors, compressed air heat exchangers, air dryers, moisture and oil separators, air tanks, containment isolation valves, and other valves and piping.

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

LRA Table 2.3.3-7 contains a list of the component types subject to an AMR for the compressed air system.

2.3.3.7.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.7, UFSAR Section 9.2.2, and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs, as discussed below.

In RAI 2.3.3.7-1, dated July 12, 2011, the staff noted on license renewal drawing LR-STP-IA-8Q119F00048#1-1, coordinates G/H-6, 7, and 8, an instrument air compressor (8Q111MC00014), including the check valves and continuation piping, shown as being within the scope of license renewal for 10 CFR 54.4(a)(3). However, for the standby unit instrument air compressors (8Q111MC00011, 8Q111MC00012, and 8Q111MC00013), the license renewal boundary is shown to end at ball valves IA9813 (coordinates F-6), IA9814 (coordinates G-5), and IA9821 (coordinates F-6). Ball valves IA9813 and IA9821 are depicted as normally open valves, which would not prevent any backflow into the standby unit instrument air compressors. A similar condition exists on the Unit 2 license renewal drawing LR-STP-IA-8Q119F00048#2-1. The staff requested that the applicant provide the basis for the license renewal boundary at the open ball valves.

In its response dated August 9, 2011, the applicant stated that the flow path from the instrument air compressors is within the scope of license renewal pursuant to 10 CFR 54.4(a)(3) for the fire protection intended function, and the scoping boundary ends at the first closable valve (inclusive) off the main instrument air flow path (i.e., the ball valves in question). The applicant also stated that the ball valves are not required to be normally closed but only provide the capability to be closed to support the fire protection intended function.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.7-1 acceptable because the applicant clarified that the 10 CFR 54.4(a)(3) license renewal boundaries (i.e., for fire protection) for the instrument air compressor are the indicated ball valves and piping on license renewal drawing LR-STP-IA-8Q119F00048#1-1. The staff noted that, even though two of the valves are normally open, the license renewal boundary is acceptable because the valves can be closed when required to perform their fire protection function. Therefore, the staff's concern described in RAI 2.3.3.7-1 is resolved.

In RAI 2.3.3.7-2, dated July 12, 2011, the staff noted on license renewal boundary drawings LR-STP-IA-8Q119F00048#1-1 and LR-STP-IA-8Q119F00048#2-1, coordinates E-5, wet air tanks (8Q111MTS0161 and 8Q112MTS0161) are shown within the scope of license renewal for 10 CFR 54.4(a)(3). However, the relief valves PSV8571 on these tanks are shown as not within the scope of license renewal. Similar air tanks (8Q111MTS0163 and 8Q112MTS0163 at coordinates E/F-2) on these license renewal boundary drawings show the relief valves as within the scope of license renewal. The staff requested that the applicant provide the basis for not including the relief valves on wet air tanks 8Q111MTS0161 and 8Q112MTS0161 within the scope of license renewal.

In its response dated August 9, 2011, the applicant stated that the relief valves PSV8571 on the wet air tanks 8Q111MTS0161 and 8Q112MTS0161 were inadvertently omitted and should be within the scope of license renewal for 10 CFR 54.4(a)(3). By letter dated November 3, 2011, the applicant revised license renewal boundary drawings, LR-STP-IA-8Q119F00048#1-1 and LR-STP-IA-8Q119F00048#2-1, to include the relief valves PSV8571 within scope of license renewal for 10 CFR 54.4(a)(3).

Based on its review, the staff finds the applicant's response to RAI 2.3.3.7-2 acceptable because the applicant included relief valves PSV8571 within the scope of license renewal for 10 CFR 54.4(a)(3) and revised the license renewal boundary drawings. Therefore, the staff's concern described in RAI 2.3.3.7-2 is resolved.

In RAI 2.3.3.7-3, dated July 12, 2011, the staff noted that license renewal boundary drawings LR-STP-IA-8Q119F00048#1-1 and LR-STP-IA-8Q119F00048#2-1, coordinates G-2, depict 1"IA1237UD8 and 1"IA2237UD8 drain piping attached to the instrument air receiver tanks (8Q111MTS0162 and 8Q112MTS0162) and downstream of drain valves IA9979 as being within the scope of license renewal for 10 CFR 54.4(a)(3). However, for similar 1-inch drain piping (1"IA1238UDS and 1"IA2238UD8) on instrument air receiver tanks (8Q111MTS0163 and 8Q112MTS0163) at coordinates E-2, the license renewal boundary is shown to end at valves IA9980 and the piping continuing after the valve is shown as not being within scope of license renewal. The staff requested that the applicant provide a basis for the different scoping classifications for the above piping downstream of the indicated drain valves.

In its response dated August 9, 2011, the applicant stated that the 1"IA1237UD8 and 1"IA2237UD8 drain piping downstream of drain valves IA9979 were incorrectly included within scope of license renewal for 10 CFR 54.4(a)(3). The applicant stated that the piping sections are properly considered as not within the scope of license renewal since they are isolatable by closable valves. By letter dated November 3, 2011, the applicant revised the license renewal drawing to depict the above drain piping excluded from the scope of license renewal.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.7-3, and the corrections to the scoping boundaries, acceptable because the applicant corrected the scoping boundary of the 1"IA1237UD8 and 1"IA2237UD8 drain piping, justified the correction because the piping is isolatable by closable valves, and revised the associated license renewal drawing. Therefore, the staff's concern described in RAI 2.3.3.7-3 is resolved.

In RAI 2.3.3.7-4, dated July 12, 2011, the staff noted that on license renewal drawing LR-STP-IA-8Q119F00048#2-2, coordinates B-6, piping with a capped end, upstream of a 4-inch by 3-inch reducer, was depicted as within the scope of license renewal for 10 CFR 54.4(a)(3). However, similar piping on license renewal drawing LR-STP-IA-8Q119F00048#1-2, coordinates B-6, is shown as not being within the scope of license renewal. The staff requested that the applicant provide a basis for not including the piping on license renewal drawing LR-STP-IA-8Q119F00048#1-2 within the scope of license renewal.

In its response dated August 9, 2011, the applicant stated that the piping upstream of the 4-inch by 3-inch reducer on license renewal drawing LR-STP-IA-8Q119F00048#1-2 (coordinates B-6) was inadvertently omitted from, and should be within, the scope of license renewal. By letter dated November 3, 2011, the applicant revised license renewal drawing LR-STP-IA-8Q119F00048#1-2 to depict the capped end piping with green highlighting (10 CFR 54.4(a)(3)).

Based on its review, the staff finds the applicant's response to RAI 2.3.3.7-4 acceptable because the applicant revised license renewal drawing LR-STP-IA-8Q119F00048#1-2 to depict the capped end piping within the scope of license renewal for 10 CFR 54.4(a)(3). The staff confirmed the appropriateness of the correction on the revised license renewal boundary drawing and confirmed that the cap and the attached piping were added to the scope of license renewal. The staff also noted that no other additional components or component types along the revised scoping boundaries, as described in the applicant's RAI response, were required to be subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.7-4 is resolved.

In RAI 2.3.3.7-5, dated July 12, 2011, the staff noted on license renewal drawing locations identified in the table below, four piping sections, two for each unit, on the indicated drawings are shown as being within the scope of license renewal but are excluded from scope of license renewal on the continuation drawings. The staff requested that the applicant provide the basis for not including the continuation piping sections within the scope of license renewal.

LRA Section/Drawing No. and Location	Continuation Piping/Drawing No.
LR-STP-IA-8Q119F05050#1 and LR-STP-IA-8Q119F05050#2 coordinates G/F-2	1"IA1826WK8 and 1"IA2826WK8 piping to LR-STP-WL-7R309F05026#1 and LR-STP-WL-7R309F05026#2, coordinates G-4, (incorrectly shown as 9F05050 G-2)
LR-STP-IA-8Q119F05050#1 and LR-STP-IA-8Q119F05050#2 coordinates F-2	1"IA1829WK8 and 1"IA2829WK8 piping to LR-STP-BR-7R189F05011#1 and LR-STP-BR-7R189F05011#2, coordinates F-6

In its response dated August 9, 2011, the applicant stated that the four piping sections (2 sections per unit) indicated in the table that are downstream of valves Unit 1—IA0827, Unit 1—IA0832, Unit 2—IA0827, and Unit 2—IA0832, were incorrectly included as within the scope of license renewal for 10 CFR 54.4(a)(3) on the license renewal boundary drawings. The applicant stated that the scoping boundaries end at valves IA0827 and IA0832 for each unit (note that the valves themselves are in-scope for 10 CFR 54.4(a)(3)) because the fire protection function can be satisfied regardless of whether the valves are open or closed. By letter dated November 3, 2011, the applicant also revised the license renewal boundary drawings to clarify the correct scoping boundaries for the piping sections.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.7-5, and the corrections to the scoping boundary, acceptable because the piping sections are downstream of closable valves and are not required for performance of the fire protection function, and because the applicant corrected the scoping classification of the piping in both license renewal boundary drawings and revised the license renewal boundary drawings accordingly. Therefore, the staff's concern described in RAI 2.3.3.7-5 is resolved.

2.3.3.7.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and license renewal boundary drawings (original and revised) 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 identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the compressed air system mechanical components within the scope of license renewal, as required by 10 CFR 54.5(a), and that the applicant adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.8 Primary Process Sampling

2.3.3.8.1 Summary of Technical Information in the Application

LRA Section 2.3.3.8 contains the discussion of the primary process sampling system and states that the system, which is comprised of the primary sampling system and the post-accident sampling system, provides the ability to collect local and remote samples from the RCS and from other contaminated systems. Additionally, the post-accident sampling system is capable of obtaining representative samples of reactor coolant and various highly contaminated containment samples without requiring a containment entry or causing high exposures to personnel. The LRA states that the system has sampling and waste pumps, a sample conditioning rack with heat exchangers, waste collection tanks and components, and associated piping, tubing, and valves to enable sampling of both liquids and gasses.

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

LRA Table 2.3.3-8 contains a list of the component types subject to an AMR for the primary process sampling system.

2.3.3.8.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.8, UFSAR Section 9.3.2, and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs, as discussed below.

In RAI 2.3.3.8-1, dated July 12, 2011, the staff noted that license renewal boundary drawings LR-STP-PS-5Z329Z00045#1 and LR-STP-PS-5Z329Z00045#2, coordinates H-4, depict piping as being within the scope of license renewal for 10 CFR 54.4(a)(2), continuing to valve XPS0327 on the same license renewal boundary drawings, coordinates C-6, where it is no longer shown within the scope of license renewal. The staff requested that the applicant provide the basis for the difference in scoping classification of the piping past valve XPS0327.

In its response dated August 9, 2011, the applicant stated that the piping from coordinates H-4 to coordinates C-6 is within scope of license renewal pursuant to 10 CFR 54.4(a)(2) for spatial interaction up until valve XPS0327. The applicant indicated that a spatial interaction termination symbol should have been placed at valve XPS0327 to identify the end of the scoping boundary for the piping. By letter dated November 3, 2011, the applicant revised license renewal boundary drawings LR-STP-PS-5Z329Z00045#1 and LR-STP-PS-5Z329Z00045#2 to indicate the scoping boundary of the piping and the spatial interaction termination symbol at valve XPS0327.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.8-1, and the corrections to the scoping boundary, acceptable because the applicant revised the license renewal boundary drawings to highlight the piping to valve XPS0327 as within scope for 10 CFR 54.4(a)(2) and to include the spatial interaction termination symbol at valve XPS0327. The staff confirmed the appropriateness of the correction and spatial interaction termination on the revised license renewal boundary drawings and that no other additional components or component types were added due to the revised scoping boundaries as a result of the RAI response. Therefore, the staff's concern described in RAI 2.3.3.8-1 is resolved.

In RAI 2.3.3.8-2, dated July 12, 2011, the staff noted that license renewal boundary drawings LR-STP-PS-5Z329Z00045#1 and LR-STP-PS-5Z329Z00045#2, coordinates D-4, depict piping continuing to valves XPS0330 within the scope of license renewal for 10 CFR 54.4(a)(2). On the same license renewal boundary drawings, at coordinates C-6, the piping is not shown within the scope of license renewal. The staff requested that the applicant provide the basis for the differing scoping classifications.

In its response dated August 9, 2011, the applicant stated that piping downstream of valves XPS0330 was inadvertently highlighted and is not within scope of license renewal for spatial interaction because the piping is located within the primary sample panel. By letter dated November 3, 2011, the applicant revised license renewal boundary drawings LR-STP-PS-5Z329Z0045#1 and LR-STP-PS-5Z329Z0045#2 to exclude the piping downstream of valves XPS0330 from scope of license renewal and to also remove the SI (spatial interaction) symbol downstream of valve XPS0209.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.8-2, and the corrections to the scoping boundary, acceptable because the piping downstream from valves XPS0330 is within the primary sample panel and, therefore, is not within scope of license renewal for spatial interaction. The applicant also revised the license renewal boundary drawings to indicate the correct scoping boundary for the piping. Therefore, the staff's concern described in RAI 2.3.3.8-2 is resolved.

In RAI 2.3.3.8-3, dated July 12, 2011, the staff noted that license renewal boundary drawings LR-STP-PS-5Z329Z00045#1 and LR-STP-PS-5Z329Z00045#2, coordinates D-1, depict piping within the scope of license renewal for 10 CFR 54.4(a)(2). The piping continues from valve CV0273, at coordinates E-8 on license renewal boundary drawings LR-STP-CV-5R179F05008#1 and LR-STP-CV-5R179F05008#2, where it is shown as not being within the scope of license renewal from valve CV0273. The staff requested that the applicant provide the basis for the difference in scope classification.

In its response dated August 9, 2011, the applicant stated the piping continuation that goes from license renewal boundary drawings LR-STP-CV-5R179F05008#1 and LR-STP-CV-5R179F05008#2 to boundary drawings LR-STP-PS-5Z329Z0045#1 and LR-STP-PS-5Z329Z0045#2 is incorrectly shown within the scope of license renewal on the latter drawings. By letter dated November 3, 2011, the applicant revised the license renewal boundary drawings LR-STP-PS-5Z329Z0045#1 and LR-STP-PS-5Z329Z0045#2 to indicate the correct scoping boundary of the piping.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.8-3, and the classification of the piping continuation as not within the scope of license renewal, acceptable because drawings LR-STP-CV-5R179F05008#1 and LR-STP-CV-5R179F05008#2 show scoping terminations (SI boundaries) that exclude the piping and associated valve CV0273 from scope. Therefore, the continuation of this piping on drawings LR-STP-PS-5Z329Z0045#1 and LR-STP-PS-5Z329Z0045#2 should also be excluded from scope. The applicant revised license renewal boundary drawings LR-STP-PS-5Z329Z0045#1 and LR-STP-PS-5Z329Z0045#2 to correct the scoping classification of the piping accordingly. Therefore, the staff's concern described in RAI 2.3.3.8-3 is resolved.

In RAI 2.3.3.8-4, dated July 12, 2011, the staff noted that license renewal boundary drawings LR-STP-PS-5Z329Z00045#1 and LR-STP-PS-5Z329Z00045#2, coordinates B-1, depict piping within the scope of license renewal for 10 CFR 54.4(a)(2). The piping continues onto license renewal boundary drawings LR-STP-ED-7Q069F90012#1 and LR-STP-ED-7Q069F90012#2, coordinates H-8, where it is no longer shown within the scope of license renewal. The staff requested that the applicant provide the basis for the continuation piping not being within the scope of license renewal.

In its response dated August 9, 2011, the applicant stated the piping continuation is shown on license renewal boundary drawings LR-STP-ED-7Q069F90012#1 and LR-STP-ED-7Q069F90012#2 as coming from the “Sample Room Reactor Grade Sampler.” The applicant confirmed that the scoping boundary of the continued piping is correctly highlighted for spatial interaction on drawings LR-STP-ED-7Q069F90012#1 and LR-STP-ED-7Q069F90012#2 (location H-8).

Based on its review, the staff finds the applicant’s response to RAI 2.3.3.8-4, and the explanation of the scoping boundary, acceptable because the applicant confirmed that the continued piping is correctly highlighted on the license renewal boundary drawings. The staff observed that the spatial interaction termination symbol for the piping on drawings LR-STP-PS-5Z329Z00045#1 and LR-STP-PS-5Z329Z00045#2 applies also to the continued piping on drawings LR-STP-ED-7Q069F90012#1 and LR-STP-ED-7Q069F90012#2. Therefore, the staff’s concern described in RAI 2.3.3.8-4 is resolved.

In RAI 2.3.3.8-5, dated July 12, 2011, the staff noted on license renewal drawing LR-STP-PS-5Z329Z00045#1, coordinates F-7, that the 1"PS1020BD7 piping section is depicted within the scope of license renewal for 10 CFR 54.4(a)(2) that ends at the intersection with the inside primary sample panel. No spatial interaction symbol is shown. The staff requested that the applicant provide the basis for the license renewal boundary at the intersection of the pipe and the panel.

In its response dated August 9, 2011, the applicant stated that the spatial interaction termination symbol was inadvertently omitted from license renewal drawing LR-STP-PS-5Z329Z00045#1 at coordinates F-7. The applicant committed to revising license renewal boundary drawing LR-STP-PS-5Z329Z00045#1 to include the spatial interaction termination symbol. The applicant provided revised license renewal boundary drawings by letter dated November 3, 2011, to meet the commitments stated in its August 9, 2011, letter. However, license renewal boundary drawing LR-STP-PS-5Z329Z00045#1 (Revision 1) was not revised to include the spatial interaction termination symbol. Therefore, the staff found the applicant’s initial response to RAI 2.3.3.8-5 not acceptable because the applicant submitted a drawing revision that did not correctly revise the drawing to add the spatial interaction termination symbol as committed to in its August 9, 2011, RAI response. The applicant provided a corrected license renewal drawing (Revision 2 of the drawing) by letter dated January 10, 2012, to supplement its original response to RAI 2.3.3.8-5. The staff reviewed Revision 2 of license renewal drawing LR-STP-PS-5Z329Z00045#1 and confirmed that the spatial interaction termination symbol was added at coordinates F-7.

Based on its review, the staff finds the applicant’s response to RAI 2.3.3.8-5, and the correction to the scoping boundary, acceptable because the applicant revised license renewal drawing LR-STP-PS-5Z329Z00045#1 to add the missing spatial interaction termination symbol. The staff observed that no additional component types or components were added to the scope of license renewal as a result of the drawing change. Therefore, the staff's concern described in RAI 2.3.3.8-5 is resolved.

In RAI 2.3.3.8-6, dated July 12, 2011, the staff noted on license renewal boundary drawings LR-STP-PS-5Z329Z00045#1 and LR-STP-PS-5Z329Z00045#2, coordinates G-4, a digital pressure indicator (DPI) located in a 10 CFR 54.4(a)(2) pipeline. The DPI is shown as not within the scope of license renewal and has been disconnected electrically and spared in place in accordance with the notes. The DPI appears to provide a pressure boundary function for a portion of the 10 CFR 54.4(a)(2) pipelines. The staff requested that the applicant provide the basis for the DPI casing not being in-scope for 10 CFR 54.4(a)(2).

In its response dated August 9, 2011, the applicant stated that DPI PI0659 was inadvertently excluded from scope of license renewal. The applicant indicated that DPI PI0659 will be included within the scope of license renewal under 10 CFR 54.4(a)(2) for spatial interaction. By letter dated November 3, 2011, the applicant revised license renewal boundary drawings LR-STP-PS-5Z329Z00045#1 and LR-STP-PS-5Z329Z00045#2 (location G-4) to highlight DPI PI0659 housing in red (10 CFR 54.4(a)(2)) for spatial interaction and also revised LRA Tables 2.3.3-8 and 3.3.2-8 to include the leakage boundary intended function for DPI PI0659.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.8-6, and the addition of the component to the scope of license renewal, acceptable because the applicant corrected the omission, included DPI PI0659 within the scope of license renewal, and revised license renewal drawings and LRA Tables 2.3.3-8 and 3.3.2-8 to reflect the addition of the component. Therefore, the staff's concern described in RAI 2.3.3.8-6 is resolved.

In RAI 2.3.3.8-7, dated July 12, 2011, the staff noted on license renewal boundary drawing LR-STP-PS-5Z549Z47501#1 and LR-STP-PS-5Z549Z47501#2, coordinates C-4, a waste collection unit depicted as being within the scope of license renewal for 10 CFR 54.4(a)(2) that contains nonsafety-related attached to safety-related components, yet no apparent seismic anchor is indicated. The staff requested that the applicant provide the basis for why the waste collection unit and contained components do not depict the equivalent anchor symbol "F.4.3" on the sample condition rack and the liquid and gas sample panel on the same drawing.

In its response dated August 9, 2011, the applicant stated the waste collection unit and contained components in-scope for 10 CFR 54.4(a)(2) do not show an equivalent anchor because a seismic anchor (at grid location C-3 to the left of valve AP0006) is credited prior to the piping attaching to the waste collection unit. The remaining piping connections to the waste collection unit are only within the scope of license renewal in 10 CFR 54.4(a)(2) for spatial interaction.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.8-7, and the explanation of the scoping boundary, acceptable because the applicant stated the waste collection unit is not being credited as an equivalent anchor for the safety-related piping on license renewal boundary drawings LR-STP-PS-5Z549Z47501#1 and LR-STP-PS-5Z549Z47501#2 and identified the applicable seismic anchor. Therefore, the staff's concern described in RAI 2.3.3.8-7 is resolved.

In RAI 2.3.3.8-8, dated July 12, 2011, the staff noted that license renewal boundary drawings LR-STP-PS-9Z329Z00047#1 and LR-STP-PS-9Z329Z00047#2, coordinates F-5, depict piping that is within the scope of license renewal for 10 CFR 54.4(a)(2). The piping continues to coordinates B-2 on license renewal boundary drawings LR-STP-CV-PS-5Z329Z00045#1 and

LR-STP-CV-PS-5Z329Z00045#2, where it is shown as not within the scope of license renewal to the drain header. The staff requested that the applicant provide the basis for the change in scoping classification of this pipe section.

In its response dated August 9, 2011, the applicant stated license renewal boundary drawings LR-STP-PS-9Z329Z00047#1 and LR-STP-PS-9Z329Z00047#2 inadvertently depict a red (10 CFR 54.4(a)(2)) highlighted pipe and a spatial interaction termination symbol. By letter dated November 3, 2011, the applicant explained that the piping is within the panel and is therefore excluded from scope of license renewal. By the same letter dated November 3, 2011, the applicant revised license renewal boundary drawings LR-STP-PS-9Z329Z00047#1 and LR-STP-PS-9Z329Z00047#2 to indicate the correct scoping boundary.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.8-8, and the corrections to the scoping boundary, acceptable because the applicant appropriately justified the exclusion of piping from the scope of license renewal and corrected license renewal boundary drawings LR-STP-PS-9Z329Z00047#1 and LR-STP-PS-9Z329Z00047#2 to remove the piping from the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.3.8-8 is resolved.

In RAI 2.3.3.8-9, dated July 12, 2011, the staff noted that license renewal boundary drawings LR-STP-PS-9Z329Z00047#1 and LR-STP-PS-9Z329Z00047#2, coordinates C-2, depict 10 CFR 54.4(a)(2) piping intersecting XPS0120, which is not depicted as being in the scope of licensing renewal. The staff requested that the applicant provide the basis for the scope change at the intersection of the two pipes.

In its response dated August 9, 2011, the applicant stated LR-STP-PS-9Z329Z00047#1 and LR-STP-PS-9Z329Z00047#2 inadvertently omitted a spatial interaction termination symbol at coordinates C-2. By letter dated November 3, 2011, the applicant revised license renewal boundary drawings LR-STP-PS-9Z329Z00047#1 and LR-STP-PS-9Z329Z00047#2 to include the spatial interaction termination symbols at the intersection of the demineralized water piping and the piping to valve XPS0120.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.8-9, and the corrections to the scoping boundary, acceptable because the applicant corrected the license renewal boundary drawing discrepancies by adding the omitted spatial interaction termination symbols. No additional component types or components were added to the scope of license renewal as a result of the response to the RAI. Therefore, the staff's concern described in RAI 2.3.3.8-9 is resolved.

2.3.3.8.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and license renewal boundary drawings (original and revised) 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 identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the primary process sampling system mechanical components within the scope of license renewal, as required by 10 CFR 54.5(a), and that the applicant adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.9 Chilled Water HVAC

2.3.3.9.1 Summary of Technical Information in the Application

LRA Section 2.3.3.9 describes the chilled water HVAC system as supplying chilled water for cooling to its four subsystems—essential chilled water system, reactor containment building (RCB) chilled water system, MAB essential chilled water system, and technical service center (TSC) chilled water system—for spatial cooling to ESF and nonsafety-related components to maintain a suitable environment during required modes of operation. The LRA also states that this system supplies cooling water to several safety-related air handling units (AHUs). Finally, the LRA states that the system is comprised of piping, valves, chiller pumps, tanks, and chillers.

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

LRA Table 2.3.3-9 contains a list of the component types subject to an AMR for the chilled water HVAC system.

2.3.3.9.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.9, UFSAR Sections 9.4.1, 9.4.2, 9.4.3, and 9.4.5.2, and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs, as discussed below.

In RAI 2.3.3.9-1, dated July 12, 2011, the staff noted that license renewal boundary drawings LR-STP-CH-3V119V10003#1 and LR-STP-CH-3V119V10003#2, coordinates B-2, depict the radwaste control room AHUs as abandoned-in-place. The AHU coils are shown on LR-STP-HM-5V109V00008#1 and LR-STP-HM-5V109V00008#2, coordinates B-5, as within the scope of license renewal for 10 CFR 54.4(a)(2). Connected piping to the AHU coils is shown within the scope of license renewal for 10 CFR 54.4(a)(1). There is no apparent reason for the change in safety class indicated at the coil/piping interface. The staff questioned whether the coils provide a safety-related function (e.g., pressure boundary) and should be within the scope of license renewal for 10 CFR 54.4(a)(1). The staff requested that the applicant provide the basis for the scoping classification of the AHU coils.

In its response dated August 9, 2011, the applicant stated that the chillers were safety-related prior to being abandoned-in-place. However, since the chillers have been taken out of service and abandoned-in-place, they are no longer safety-related, nor do they have a 10 CFR 54.4(a)(1) intended function. The chillers have been included within the scope of license renewal for 10 CFR 54.4(a)(2) for spatial interaction and for structural integrity since they remain attached to the safety-related piping.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.9-1, and the explanation of the scoping boundary, acceptable because the applicant explained that, while the chillers are not safety-related and do not have a 10 CFR 54.4(a)(1) intended function, they are included within the scope of license renewal for spatial interaction and structural integrity. Therefore, the staff's concern described in RAI 2.3.3.9-1 is resolved.

In RAI 2.3.3.9-2, dated July 12, 2011, the staff noted that license renewal boundary drawings LR-STP-CH-5V149V00021#1 and LR-STP-CH-5V149V00021#2, coordinates G-8, depict expansion tank vent piping section 1"CH1193XC7/1"CH2193XC7 and relief piping section 1"CH1193XC7/1"CH2193XC7 as not being within the scope of license renewal. The staff requested that the applicant provide the basis for the exclusion of the expansion tank vent and relief piping and associated isolation valves from the scope of license renewal.

In its response dated August 9, 2011, the applicant stated that the vent and relief piping sections contain dry gas due to the presence of a nitrogen blanket in the tank and are not within the scope of license renewal for spatial interaction.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.9-2 acceptable because the applicant explained that the expansion tank vent and relief valve piping sections contain dry gas. The staff noted that, since the piping under consideration is downstream of a normally closed vent valve, with the other portion being downstream of the (normally closed) relief valve, the piping would contain dry gas, whether nitrogen or air. The staff also noted that the license renewal boundary drawings depict the spatial interaction boundary flags on the expansion tanks themselves, which indicates that the spatial interaction boundaries terminate there and do not extend beyond the tanks. Therefore, the staff's concern described in RAI 2.3.3.9-2 is resolved.

In RAI 2.3.3.9-3, dated July 12, 2011, the staff noted that license renewal boundary drawings LR-STP-CH-6V109V00010#1 and LR-STP-CH-6V109V00010#2, coordinates B-5, depict an expansion tank within the scope of license renewal for 10 CFR 54.4(a)(2). The expansion tank has vent piping section 1"CH1288XC7/1"CH2188XC7 and relief piping section 1"CH1194XC7/1"CH2194XC7, which are depicted as not being within the scope of license renewal. The staff requested that the applicant provide the basis for the exclusion of the expansion tank vent and relief piping and associated isolation valves from the scope of license renewal.

In its response dated August 9, 2011, the applicant stated the vent and relief piping sections contain dry gas due to the presence of a nitrogen blanket in the tank and are not within scope of license renewal for spatial interaction.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.9-3 acceptable because the applicant stated that the expansion tank vent and relief valve piping sections contain dry gas. The staff noted that, since the piping under consideration is downstream of a normally closed vent valve, with the other portion being downstream of the (normally closed) relief valve, the piping would contain dry gas, whether nitrogen or air. The staff also noted that the license renewal boundary drawings depict the spatial interaction boundary flags on the expansion tanks themselves, which indicates that the spatial interaction boundaries terminate there and do not extend beyond the tanks. Therefore, the staff's concern described in RAI 2.3.3.9-3 is resolved.

2.3.3.9.3 Conclusion

The staff reviewed the LRA, UFSAR, 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 identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the chilled water HVAC system mechanical components within the scope of license renewal, as required by 10 CFR 54.5(a), and that the applicant adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.10 Electrical Auxiliary Building and Control Room HVAC System

2.3.3.10.1 Summary of Technical Information in the Application

LRA Section 2.3.3.10 describes the electrical auxiliary building (EAB) and control room HVAC system and states that its purpose is to supply ventilation to the EAB main areas, the control room envelope, and the TSC. The LRA states that this system contains three subsystems, one each for the main area HVAC, the control room envelope, and the TSC. The LRA also states that the system operates to maintain habitability and temperature requirements for the areas served, maintain battery room hydrogen concentrations below 2 percent, and maintain a positive pressure in the control room to prevent air in-leakage.

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

LRA Table 2.3.3-10 contains a list of the component types subject to an AMR for the EAB and control room HVAC system.

2.3.3.10.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.10 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.10.3 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 concludes that the applicant appropriately identified the EAB and control room HVAC system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.11 Fuel Handling Building HVAC

2.3.3.11.1 Summary of Technical Information in the Application

LRA Section 2.3.3.11 describes the FHB HVAC system, and states that its purposes are as follows:

- to provide continuous airflow across the spent fuel pool
- to control ventilation of FHB areas, especially those where ESF equipment is located
- to maintain a negative pressure in the FHB and reroute exhaust air from the FHB to reduce post-accident dosages at the site boundary

The section also states that the system is comprised of three subsystems—the supply air subsystem, the supplementary coolers subsystem, and the exhaust air subsystem.

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

LRA Table 2.3.3.11 contains a list of the component types subject to an AMR for the FHB HVAC system.

2.3.3.11.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.11 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.11.3 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 concludes that the applicant appropriately identified the fuel building HVAC system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.12 Mechanical Auxiliary Building HVAC

2.3.3.12.1 Summary of Technical Information in the Application

LRA Section 2.3.3.12 discusses the MAB HVAC system. The section states that this system maintains the air environment of the MAB to ensure acceptable conditions for both personnel and equipment. The LRA also states that this system maintains a slight negative pressure in the MAB to prevent unmonitored, contaminated air leakage to the environment. Finally, the section states that this system is comprised of three subsystems—the main supply and exhaust subsystem, the supplementary cubicle coolers subsystem, and the supplementary supply and exhaust subsystem.

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

LRA Table 2.3.3-12 contains a list of the component types subject to an AMR for the MAB HVAC system.

2.3.3.12.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.12 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.12.3 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 concludes that the applicant appropriately identified the MAB HVAC mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.13 Miscellaneous HVAC (In Scope)

2.3.3.13.1 Summary of Technical Information in the Application

LRA Section 2.3.3.13 describes the miscellaneous HVAC systems (in scope). The section states that these systems operate to provide thermal cooling and heating for an acceptable environment for personnel and equipment in the ECW structure and in the fire pump house. The LRA states that each system consists of supply dampers, exhaust dampers, and ventilation fans for the respective area served.

The LRA classifies these systems as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(3).

LRA Table 2.3.3-13 contains a list of the component types subject to an AMR for the miscellaneous HVAC systems (in scope).

2.3.3.13.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.13 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.13.3 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 concludes that the applicant appropriately identified the miscellaneous HVAC systems mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.14 Reactor Containment Building HVAC

2.3.3.14.1 Summary of Technical Information in the Application

LRA Section 2.3.3.14 describes the RCB HVAC system as being comprised of two parts—the RCB HVAC system and the main steam isolation valve (MSIV) cubicle (building) system. The LRA states that these systems maintain ambient air conditions in their respective structures to provide an acceptable environment for equipment operation.

The section states that the RCB HVAC system uses reactor containment fan coolers and containment purge subsystems to circulate, cool, and decontaminate the containment atmosphere both during normal operations and in post-LOCA situations. The LRA states that the RCB HVAC system also acts to control post-LOCA hydrogen concentration and to provide air purging for the tendon gallery tunnel's atmosphere. Finally, the LRA states that the MSIV cubicle (building) HVAC system maintains ambient air conditions for the AFW pump rooms and for the MSIV cubicle building.

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

LRA Table 2.3.3-14 contains a list of the component types subject to an AMR for the RCB HVAC system.

2.3.3.14.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.14 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.14.3 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 concludes that the applicant appropriately identified the RCB HVAC mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.15 Standby Diesel Generator Building HVAC

2.3.3.15.1 Summary of Technical Information in the Application

LRA Section 2.3.3.15 discusses the standby diesel generator building (DGB) HVAC system. The section describes the purposes of this system as follows:

- to maintain an acceptable environment for the equipment by controlling ambient room temperatures within design limits
- to minimize dust levels in the rooms when the generators are not running
- to be a continuous supply of fresh air in order to purge any fuel oil fumes from the fuel oil storage tank rooms

The LRA also states that this system is made up of two subsystems—the DGB normal heating and ventilating subsystem and the DGB emergency ventilation subsystem.

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(3).

LRA Table 2.3.3-15 contains a list of the component types subject to an AMR for the standby DGB HVAC system.

2.3.3.15.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.15 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.15.3 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 concludes that the applicant appropriately identified the standby DGB HVAC mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.16 Containment Hydrogen Monitoring and Combustible Gas Control

2.3.3.16.1 Summary of Technical Information in the Application

LRA Section 2.3.3.16 describes the containment hydrogen monitoring and combustible gas control system and states that its purpose is to both monitor and to control hydrogen concentrations in the containment atmosphere. The LRA states that this system consists of containment hydrogen monitors and electric hydrogen recombiner units, along with associated piping, tubing, valves, pumps, and heat exchangers. The LRA states that although the electric recombiners are no longer needed for DBAs and provide no safety function, they are still maintained as environmentally qualified under the EQ Program.

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

LRA Table 2.3.3-16 contains a list of the component types subject to an AMR for the containment hydrogen monitoring and combustible gas control system.

2.3.3.16.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.16 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.16.3 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 concludes that the applicant appropriately identified the containment hydrogen monitoring and combustible gas control system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.17 Fire Protection

2.3.3.17.1 Summary of Technical Information in the Application

LRA Section 2.3.3.17 discusses the fire protection system. The LRA states that the purposes of this system are to provide capabilities to detect, control alarm and extinguish fires within the plant, and minimize effects of fires upon plant SCs, particularly so that a safe shutdown of the plant can be achieved. The LRA also states that the system is comprised of two 300,000-gallon storage tanks, diesel-driven fire pumps, fire pump heat exchangers, hydrants, hose stations, sprinklers and deluge subsystems, and associated valves, piping, and controls.

The LRA describes the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

LRA Tables 2.3.3-17 and 3.3.2-17 contains a list of the component types subject to an AMR for the fire protection system.

2.3.3.17.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.17, 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, and “Fire Protection Evaluation and Comparison to BTP [Branch Technical Position] APCSB [Auxiliary and Power Conversion Systems Branch] 9.5-1, Appendix A Report,” (i.e., the applicant’s UFSAR description of its approved Fire Protection Program) by means of a point-by-point comparison with Appendix A to BTP APCSB 9.5-1, “Guidelines for Fire Protection for Nuclear Power Plants,” May 1, 1976. The staff also reviewed the fire protection documents cited in the South Texas Project Facility Operating Licenses for Unit 1 and Unit 2, Condition 2.E, “Fire Protection,” NUREG-0781, “Safety Evaluation Report Related to the Operation of South Texas Project, Units 1 and 2,” dated April 1986, and its supplements.

During its review, the staff evaluated the system functions described in the LRA and UFSAR to confirm that the applicant had included in the scope of license renewal all 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 confirm that the applicant had included all passive or long-lived components subject to an AMR in accordance with 10 CFR 54.21(a)(1).

During its review of LRA Section 2.3.3.17, 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 its letter dated April 14, 2011, the staff, via RAI 2.3.3.17-1, stated that the following LRA boundary drawings show the following fire protection systems/components as out of scope (i.e., not colored in green):

LRA Drawing	Systems/Components	Location
LR-STP-FP-7Q271F00046	Fire water suppression systems associated with transformers balance of plant (BOP) 1D1 and 1D2	Fire protection loop
LR-STP-FP-7Q271F00046	Fire water suppression system in the lighting DGB	Fire protection loop

LRA Drawing	Systems/Components	Location
LR-STP-FP-7Q272F00046	Fire water suppression systems associated with transformers BOP 2D1 and 2D2	Fire protection loop
LR-STP-FP-7Q272F00046	Several fire water suppression systems associated with various buildings (e.g., building 15, building 27, building 33, building 45, building 50, building 52, and building 71)	B7 and D8

The staff requested that the applicant confirm whether the fire protection systems/components listed above are within the scope of license renewal in accordance with 10 CFR 54.4(a) and, if so, whether 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, therefore, not subject to an AMR, the staff requested that the applicant provide justification for the exclusion.

In its response, dated May 12, 2011, the applicant provided scoping and screening results of the fire protection components in question in the license renewal drawings LR-STP-FP-7Q271F00046 and LR-STP-FP-7Q272F00046. For fire water suppression systems associated with transformers BOP 1D1, 1D2, 2D1, and 2D2, the applicant stated that BOP transformers 1D1, 1D2, 2D1, and 2D2 are nonsafety, do not perform any license renewal related function, and are not within the scope of license renewal. In addition, the applicant stated that these transformers are not located within 50 ft of a safety-related building and, therefore, fire suppression for the BOP transformers is not within the scope of license renewal and is not subject to aging management.

Based on the applicant's response, the staff reviewed the STP, Units 1 and 2, commitment to 10 CFR 50.48, "Fire protection" (i.e., approved Fire Protection Program, a point-by-point comparison with Appendix A to BTP APCSP 9.5-1, documented in the STP Fire Hazard Report Section 4.2). Section D.1(h) of the Appendix A to BTP APCSP 9.5-1 recommends that buildings containing safety-related systems should be protected from exposure or spill fires involving oil-filled transformers by locating such transformers at least 50 ft distant or ensuring that such building walls within 50 ft of oil-filled transformers are without openings and have a fire resistance rating of at least 3 hours. Based on the applicant's information in the fire hazard analysis report and compliance statements—namely that the BOP transformers 1D1, 1D2, 2D1, and 2D2 are located at least 50 ft away from any building containing safety-related equipment—the staff finds that the fire protection systems for the subject outdoor oil-filled transformers were correctly excluded from the scope of license renewal. Therefore, the staff's concern described in the RAI is resolved.

For the fire water suppression system in the lighting DGB, the applicant stated that the fire water suppression system in the fire protection loop lighting DGB was incorrectly omitted from the scope of license renewal as well as the lighting diesel generator. The lighting diesel generator provides power to outdoor lighting to illuminate access routes that may require operator travel to various safe shutdown components. By letter dated November 3, 2011, the applicant provided updated license renewal drawings that identified the lighting diesel generator, the lighting diesel generator fuel supply, the lighting DGB, and the fire water suppression system as within the scope of license renewal.

The staff reviewed the applicant's response, which confirmed that the fire water suppression system in the lighting DGB has been included within the scope of license renewal and is subject to an AMR. Therefore, the staff's concern described in the RAI is resolved.

For fire water suppression systems associated with buildings 15, 27, 33, 45, 50, 52, and 71, the applicant stated that buildings 27, 33, 45, 50, 52 and 71 are located outside the protected area and contain no equipment important to safety. A fire in any of these buildings will not affect equipment or components important to safety. Therefore, fire suppression components in these buildings are not within the scope of license renewal. Building 15 has been removed from the site. By letter dated November 3, 2011, the applicant revised the license renewal boundary drawing to remove Building 15.

Based on its review, the staff finds the applicant's response acceptable. The fire water suppression systems associated with buildings 27, 33, 45, 50, 52, and 71 do not have a license renewal intended function and are, therefore, excluded from the scope of license renewal and are not subject to an AMR. Building 15 has been removed entirely from the site, so there is no longer an associated fire water suppression system of concern. By letter dated November 3, 2011, the applicant revised the license renewal boundary drawing to remove Building 15.

Section 9.5.1.2.1, "Fire Protection Water Supply System," of the UFSAR on page 9.5-5, states that the water supply to refill the fire water storage tanks is normally provided from the fresh water system, which takes suction from a settling basin. This section also states that, in the event of a failure in this system, the tank is refilled directly from the site well water system. LRA Section 2.3.3.17 discusses requirements for the fire water supply system but does not mention site well water pumps and associated components.

The staff noted that LRA boundary drawing LR-STP-FP-7Q270F00006 shows the site well water system and its components as out of scope (i.e., not colored in green). In its letter dated April 14, 2011, the staff issued RAI 2.3.3.17-2, requesting that the applicant verify whether the site well water pumps and associated components to the fire water storage tanks are within the scope of license renewal in accordance with 10 CFR 54.4(a) and, if so, whether they are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff requested that, if these components are excluded from the scope of license renewal and, therefore, not subject to an AMR, the applicant provide justification for the exclusion.

In its response to RAI 2.3.3.17-2 dated May 12, 2011, the applicant provided scoping and screening results of the fire protection components in question in the license renewal drawing LR-STP-FP-7Q270F00006. The applicant stated that the fire water tanks are sized so that makeup is not required to meet the fire event safe shutdown requirements and that site well water pumps and associated components are only for augmenting storage tank capacity. The applicant also stated that, as documented in its FHAR, two separate tanks—300,000 useable gallons each—are the dedicated water supplies for the fire pumps and can be interconnected so that the pumps can take suction from either or both. Finally, the applicant stated that, as documented in UFSAR Section 9.5.1.2.1, while the site well water system provides makeup to the fire water tanks, no credit is taken for refilling the tanks to meet the requirements of safe shutdown fire events. Therefore, the applicant concluded that the site well water system that provides makeup to the fire water tanks is not within the scope of license renewal.

Based on its review, the staff finds the applicant's response acceptable because it clarifies that the site well water system and associated piping and components are not required to support any fire protection intended functions for license renewal. The two fire water tanks are adequate to meet fire protection system demands in the event of a fire, and the STP FHAR does not credit the refilling of the tanks to meet the requirements of 10 CFR 50.48 for a fire event.

LRA Tables 2.3.3.17 and 3.3.2-17 exclude several types of fire protection components, including the following:

- fire hose stations, fire hose connections, and hose racks
- floor drains for fire water
- dikes and curbs for oil spill confinement
- components in reactor coolant pump oil collection system

In its letter dated April 14, 2011, the staff issued RAI 2.3.3.17-3, requesting that the applicant verify whether LRA Tables 2.3.3-17 and 3.3.2-17 should include the components listed above. If they are excluded from the scope of license renewal and not subject to an AMR, the staff requested that the applicant justify their exclusion.

In a letter dated May 12, 2011, the applicant provided the results of the scoping and screening for the fire protection system component types listed above. In reviewing its response to the RAI, the staff found that the applicant had addressed and resolved each item in the RAI, as discussed below.

Fire hose stations, fire hose connections, and hose racks are within the scope of license renewal and subject to an AMR. The component type, "valve," as identified in LRA Table 2.3.3-17, is used to represent fire hose stations and fire hose racks. Each individual fire hose station and fire hose rack also includes an isolation valve in its fire water supply. For fire hose stations and hose racks within the scope of license renewal and subject to an AMR, the representative firewater isolation valve has been highlighted in green.

Floor drains used for the removal of firewater are evaluated as component type "piping" and are identified in LRA Tables 2.3.3-23 and 2.3.3-24 as components within the scope of license renewal and subject to an AMR.

Dikes and curbs for oil spill confinement are provided for oil-filled transformers. The dikes for the ESF transformers are evaluated as component type "concrete element" and are identified in LRA Table 2.4-7 as within the scope of license renewal and subject to an AMR. These dikes and curbs prevent the spreading of a fire that could affect equipment or components important to safety. Each ESF transformer is located in a separate diked pit sized to contain 100 percent of the transformer oil.

Components in the reactor coolant pump oil collection system, identified as component types "tank," "valve," and "piping" in LRA Table 2.3.1-2, are within the scope of license renewal and subject to an AMR. The reactor coolant pump oil collection system components are shown highlighted in green as within the scope of license renewal on license renewal boundary drawings LR-STP-RC-5R379F05042#1 and LR-STP-RC-5R379F05042#2 for Units 1 and 2. Reactor coolant pump oil collection system component types, "flame arrestor" and "splash guard," are within the scope of license renewal, subject to an AMR, and will be added to LRA Table 2.3.1-2 and LRA Table 3.1.2-2.

Based on its review, the staff found the applicant's response to RAI 2.3.3.17-3 acceptable because it resolved the staff's concerns regarding scoping and screening of fire protection system components listed in the RAI. Therefore, the staff's concern described in the RAI is resolved.

2.3.3.17.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and license renewal boundary drawings (original and revised) 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 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 54.5(a), and that the applicant adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.18 Standby Diesel Generator Fuel Oil Storage and Transfer

2.3.3.18.1 Summary of Technical Information in the Application

LRA Section 2.3.3.18 contains the discussion for the standby diesel generator fuel oil storage and transfer system and states that this system provides for the storage and transfer of fuel oil for the standby diesel generators in order to allow them to operate continuously for 7 days or longer during DBEs. The LRA states that the system contains fuel oil storage tanks, fuel oil drain tanks, flame arrestors, pumps, associated valves, and piping.

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

LRA Table 2.3.3-18 contains a list of the component types subject to an AMR for the standby diesel generator fuel oil storage and transfer system.

2.3.3.18.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.18 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.18.3 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 concludes that the applicant appropriately identified the standby diesel generator fuel oil storage and transfer system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.19 Chemical and Volume Control

2.3.3.19.1 Summary of Technical Information in the Application

LRA Section 2.3.3.19 describes the CVCS and states that it is comprised of four subsystems—the charging, letdown, and seal water subsystem; the reactor coolant purification and chemistry control subsystem; the reactor makeup control subsystem; and the boron thermal regeneration subsystem. The section states that this system has the following purposes:

- maintain RCS water inventory
- supply seal water injection for the reactor coolant pump seal package
- maintain concentrations within limits for RCS chemistry, activity, and soluble boron (a neutron absorber)
- provide purification for the RCS

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

LRA Table 2.3.3-19 contains a list of the component types subject to an AMR for the CVCS system.

2.3.3.19.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.19 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.19.3 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 concludes that the applicant appropriately identified the CVCS mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.20 Standby Diesel Generator and Auxiliaries

2.3.3.20.1 Summary of Technical Information in the Application

LRA Section 2.3.3.20 describes the standby diesel generator and auxiliaries system as being comprised of the following subsystems:

- the diesel generator cooling water system
- the diesel generator starting system
- the diesel generator lubrication system
- the diesel generator combustion air intake and exhaust system

The LRA states that this system provides onsite emergency electrical power for safety-related Class IE loads in case offsite power is lost during normal or accident conditions. The LRA also states that fuel oil for the generators is supplied by the standby diesel fuel oil storage and transfer system. The section also states that this system is made up of pumps (both engine-driven and electrical), coolers and heat exchangers, air compressors, dryers, air tanks, lube oil filters and strainers, and associated piping and valves.

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

LRA Table 2.3.3-20 contains a list of the component types subject to an AMR for the standby diesel generator and auxiliaries system.

2.3.3.20.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.20, UFSAR Sections 8.3.1.1, 9.5.4, 9.5.5, 9.5.6, 9.5.7, and 9.5.8., and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs, as discussed below.

In RAI 2.3.3.20-1, dated July 12, 2011, the staff noted that license renewal boundary drawings LR-STP-DG-5Q159F22540#1 and LR-STP-DG-5Q159F22540#2, coordinates E-3, E-5, and E-8, depict turbo housing components within the scope of license renewal for 10 CFR 54.4(a)(1). The turbo housing component was not included in Table 2.3.3-20. The staff requested that the applicant provide the basis for excluding the turbo housing component type from Table 2.3.3-20.

In its response dated August 9, 2011, the applicant stated the turbocharger housings are evaluated as component type "Blower" in Tables 2.3.3-20 and 3.3.2-20 with a pressure boundary intended function.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.20-1 acceptable because the applicant stated the turbocharger housings are evaluated as component type "Blower" in Tables 2.3.3-20 and 3.3.2-20; therefore, they are within the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.3.20-1 is resolved.

In RAI 2.3.3.20-2, dated July 12, 2011, the staff noted that license renewal boundary drawings LR-STP-DG-5Q159F22540#1 and LR-STP-DG-5Q159F22540#2, coordinates F-2, F-5, and F-7, depict standpipe tank components within the scope of license renewal for 10 CFR 54.4(a)(1) that provide a pressure boundary function. The standpipe tank component was not included in LRA Table 2.3.3-20. The staff requested that the applicant provide the basis for excluding the standpipe tank component type from Table 2.3.3-20.

In its response dated August 9, 2011, the applicant stated the standpipe components are evaluated as component type "piping" in LRA Tables 2.3.3-20 and 3.3.2-20 with a pressure boundary intended function.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.20-2 acceptable because the applicant stated the standpipe components are evaluated as component type "piping" in LRA Tables 2.3.3-20 and 3.3.2-20; therefore, they are within the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.3.20-2 is resolved.

In RAI 2.3.3.20-3, dated July 12, 2011, the staff noted that license renewal boundary drawings LR-STP-DG-5Q159F22546#1 and LR-STP-DG-5Q159F22546#2, coordinates F-2, F-5, and F-7, depict starter air receiver tank components as being within the scope of license renewal for 10 CFR 54.4(a)(1) and providing a pressure boundary function. The starter air receiver tank component was not included in Table 2.3.3-20. The staff requested that the applicant provide the basis for excluding the starter air receiver tank component from LRA Table 2.3.3-20.

In its response dated August 9, 2011, the applicant stated starting air receivers are evaluated as component type "accumulator" in LRA Tables 2.3.3-20 and 3.3.2-20 with a pressure boundary intended function.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.20-3 acceptable because the applicant stated the starting air receivers are evaluated as component type "accumulator" in LRA Tables 2.3.3-20 and 3.3.2-20; therefore, they are within the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.3.20-3 is resolved.

In RAI 2.3.3.20-4, dated July 12, 2011, the staff noted that it could not locate diesel lube oil reservoir tanks on license renewal boundary drawings LR-STP-DG-50159F22542#1 and LR-STP-DG-50159F22542#2 and LR-STP-DG-50159F22543#1 and LR-STP-DG-50159F22543#2. The staff requested that the applicant clarify whether there are diesel lube oil reservoir tanks in the system and, if there are, explain if they are in scope and where they are located.

In its response dated August 9, 2011, the applicant stated the diesel generator lube oil system is a wet sump oiling system and does not contain lube oil reservoir tanks.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.20-4 acceptable because the diesel generator lube oil system is a wet sump oiling system and does not contain lube oil reservoir tanks. Therefore, the staff's concern described in RAI 2.3.3.20-4 is resolved.

In RAI 2.3.3.20-5, dated July 12, 2011, the staff noted that it could not locate on license renewal boundary drawings LR-STP-DG-50159F22546#1 and LR-STP-DG-50159F22546#2, coordinates E-2, E-4, E-5, and E-7, membrane dryers attached to 1-inch stainless steel piping within the scope of license renewal, with the termination symbols of "F.4.a." However, during the scoping and screening audit of May 16-19, 2011, the staff identified ½-inch copper piping attached downstream of the 1-inch stainless steel piping. The staff noted that the ½-inch copper piping is attached to the membrane dryers. The configuration of the ½-inch copper piping on the membrane dryers does not appear to meet the description of base-mounted components as described in NEI 95-10, Appendix F. The staff requested that the applicant provide the basis for designating the membrane dryers as base-mounted components with the physical configuration, as described above.

In its response dated August 9, 2011, the applicant stated the LRA incorrectly designates the membrane dryers as base-mounted terminal components as shown on boundary drawings LR-STP-DG-5Q159F22546#1 and LR-STP-DG-5Q159F22546#2. The applicant stated that the ½-inch copper tubing should be credited as a flexible connection per NEI 95-10; therefore, loads would not be transmitted to downstream safety-related piping. The applicant corrected the copper piping designation and removed the membrane dryers from the scope of license renewal. By letter dated November 3, 2011, the applicant revised the license renewal boundary drawings and associated tables to reflect the stated changes to the LRA.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.20-5, and the corrections to the scoping boundaries, acceptable because flexible piping does not transmit loads downstream to connected safety-related components. The applicant corrected license renewal boundary drawings to show the 10 CFR 50.54(a)(2) terminations at the 1-inch stainless steel piping to ½-inch copper tubing. LRA Tables 2.3.3-20 and 3.3.2-20 and LRA Section 2.3.3.20 were also revised to remove the component type "dryer," and Section 2.3.3.20

was revised to remove air dryers from the system description. Therefore, the staff's concern described in RAI 2.3.3.20-5 is resolved.

2.3.3.20.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and license renewal boundary drawings (original and revised) to determine whether the applicant identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the standby diesel generator and auxiliaries system mechanical components within the scope of license renewal, as required by 10 CFR 54.5(a), and that the applicant 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 Nonsafety-Related Diesel Generators and Auxiliary Fuel Oil

2.3.3.21.1 Summary of Technical Information in the Application

LRA Section 2.3.3.21 describes the nonsafety-related diesel generators and auxiliary fuel oil system as consisting of three types of nonsafety-related diesel generators, the auxiliary fuel oil subsystem, and associated piping, valves, and components. The LRA states that the purpose of this system is to provide backup electrical power or motive power for several nonsafety-related, non-Class 1E loads:

- select turbine auxiliary loads
- non-Class 1E battery chargers
- certain ventilating fans
- positive displacement charging pump
- instrument air compressors
- motive power for diesel-driven fire pumps

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(3) except for the TSC diesel generators, regarding which the section states that they do not provide any license renewal functions.

LRA Table 2.3.3-21 contains a list of the component types subject to an AMR for the nonsafety-related diesel generators and auxiliary fuel oil system.

2.3.3.21.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.21 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.21.3 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 concludes that the applicant appropriately identified the nonsafety-related diesel generators and auxiliary fuel oil system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a).

The staff also finds that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.22 Liquid Waste Processing

2.3.3.22.1 Summary of Technical Information in the Application

LRA Section 2.3.3.22 describes the liquid waste processing system and states that its purpose is to reduce activity and chemical concentrations from liquid wastes collected from various floor and equipment drains; from laundry, chemical, condensate polishing wastes; and from drainage to the reactor coolant drain tank. The section also states that the system provides containment isolation for the reactor coolant drain tank downstream discharge piping.

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

LRA Table 2.3.3-22 contains a list of the component types subject to an AMR for the liquid waste processing system.

2.3.3.22.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.22, UFSAR Sections 3.1.2.6.2.3 and 11.2, and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs, as discussed below.

In RAI 2.3.3.22-1, dated July 12, 2011, the staff noted that on the license renewal drawing at locations/lines identified in the table below, the piping sections on the main drawings are shown as within the scope of license renewal but are shown as not within the scope of license renewal on the continuation drawings. The staff requested that the applicant provide the basis for the change in scoping classification for these piping sections.

LRA Section/Drawing No. and Coordinate Location	Continuation Piping/Drawing No.
LR-STP-WL-7R309F05024#1 and LR-STP-WL-7R309F05024#2 coordinates G-6	2" piping (CV1259UD7 and CV2259UD7) on LR-STP-CV-5R179F05009#1 and LR-STP-CV-5R179F05009#2 coordinates A-8
LR-STP-WL-5R309F05022#1 and LR-STP-WL-5R309F05022#2 coordinates E-6	1" piping on LR-STP-RC-5R149F05004#1 and LR-STP-RC-5R149F05004#2 coordinates F-6
LR-STP-WL-7R309F05023#1 and LR-STP-WL-7R309F05023#2 coordinates A-2	3" piping (WL1048WG7/3"WL2048WG7) on LR-STP-WL-7R309F90001#1 and LR-STP-WL-7R309F90001#2 coordinates E-8

In its response dated August 9, 2011, the applicant stated the following:

- A spatial termination symbol was missing on license renewal boundary drawings LR-STP-WL-7R309F05024#1 and LR-STP-WL-7R309F05024#2. The downstream components on continuation drawings (LR-STP-CV-5R179F05009#1 and LR-STP-CV-5R179F05009#2) are located in a room with no safety-related components. By letter dated November 3, 2011, the applicant revised license renewal boundary drawings LR-STP-WL-7R309F05024#1 and LR-STP-WL-7R309F05024#2 to depict the spatial interaction termination symbols.

- A spatial termination symbol was missing at valve WL1501 on license renewal boundary drawings LR-STP-WL-5R309F05022#1 and LR-STP-WL-5R309F05022#2. The piping downstream of valve WL1501 is a dry gas atmosphere and not in scope. By letter dated November 3, 2011, the applicant revised license renewal boundary drawings LR-STP-WL-5R309F05022#1 and LR-STP-WL-5R309F05022#2 to remove the piping downstream of valve WL1501 from scope of license renewal and depict the spatial interaction termination symbols at valve WL1501.

- The 3"WL1048WG7 piping and components prior to the spatial interaction termination symbol on license renewal drawing LR-STP-WL-7R309F90001#1 should be depicted as being within the scope of license renewal. The 3"WL2048WG7 piping and components on license renewal boundary drawing LR-STP-WL-7R309F90001#2 were highlighted correctly in red (10 CFR 54.4(a)(2)). By letter dated November 3, 2011, the applicant revised license renewal drawing LR-STP-WL-7R309F90001#1 to depict the 3"WL1048WG7 piping and components prior to the spatial interaction termination symbol with red highlighting.

Based on its review, the staff finds the applicant’s response to RAI 2.3.3.22-1, and the corrections to the scoping boundaries, acceptable because the applicant explained and corrected the scoping discrepancies between the main drawings and the continuation drawings and provided revised license renewal boundary drawings. No additional component types were included as a result of the RAI response. Additional piping and valves were added to the scope of license renewal and subject to aging management. Therefore, the staff’s concern described in RAI 2.3.3.22-1 is resolved.

In RAI 2.3.3.22-2, dated July 12, 2011, the staff noted that it could not locate seismic anchors during its review of the liquid waste processing system drawings on the following nonsafety-related piping sections, which are depicted as in-scope of license renewal for 10 CFR 54.4(a)(2) and directly connected to safety-related valves. The staff requested that the applicant provide the locations of the seismic anchors for the below examples.

Nonsafety/Safety Interface Location	Description
LR-STP-WL-7R309F05024#1 and LR-STP-WL-7R309F05024#2 coordinates H-6	2" piping (WL1401WG7/2"WL2401WG7) connected to 3" line piping (WL1081WG7/WL2081WG7) which in turn is connected to safety-related piping including 2"CV1034PB3/2"CV2034PB3
LR-STP-WL-5R309F05022#1 and LR-STP-WL-5R309F05022#2 coordinates E-6	Piping from drawing LR-STP-RC-5R149F05001#1 and LR-STP-RC-5R149F05001#2 connected to valves FV3400

In its response dated August 9, 2011, the applicant stated the following:

- Spatial interactions termination symbols were missing for piping sections 2"WL1093WG7/2"WL2093WG7, 2"WL1094WG7/2"WL2094WG7, and 2"WL1401WG7/2"WL2401WG7. The applicant also identified that the structural integrity terminations were missing for these piping sections, but found equivalent anchors along piping sections 3"WL1081WG7/3"WL2081WG7. By letter dated November 3, 2011, the applicant revised license renewal boundary drawings LR-STP-WL-7R309F05024#1 and LR-STP-WL-7R309F05024#2 to depict structural integrity attached terminations for piping sections 2"WL1094WG7/2"WL2094WG7 and 2"WL1081 WG7/2"WL2081WG7.

The applicant also included the spatial interaction termination symbols to piping sections 2"WL1093WG7/2"WL2093WG7, 2"WL1094WG7/2"WL2094WG7, and 2"WL1401WG7/2"WL2401 WG7.

- The branches on license boundary drawings LR-STP-WL-5R309F05022#1 were terminated with equivalent anchors except for two piping sections. Two piping sections (4"RC1041UD7 and 3"RC1034UD7) continue to license renewal boundary drawings LR-STP-RC-5R149F05004#1 and #2, where they are attached to the PRTs, which are all within scope of license renewal. The applicant stated that the PRT serves as an appropriate “F.4.a” base-mounted component for the two piping sections. By letter dated November 3, 2011, the applicant revised license renewal drawings LR-STP-RC-5R149F05004#1 and LR-STP-RC-5R149F05004#2 to include the “F.4.a” equivalent anchor symbol to the PRT.

Based on its review, the staff finds the applicant’s response to RAI 2.3.3.22-2, and the corrections to the scoping boundaries, acceptable because the applicant corrected the discrepancies regarding the location of the seismic anchors and spatial interaction termination locations, provided appropriate reasoning, and provided corrected license renewal boundary drawings. Therefore, the staff’s concern described in RAI 2.3.3.22-2 is resolved.

In RAI 2.3.3.22-3, dated July 12, 2011, the staff noted that license renewal drawing LR-STP-WL-7R309F90001#2, coordinates D-1, C-4, C-7, E-7, and E-8, depict portions of several piping sections as being within the scope of license renewal for 10 CFR 54.4(a)(2). However, similar piping sections on license renewal drawing LR-STP-WL-7R309F90001#1 are shown as not within the scope of license renewal. The staff requested that the applicant clarify the difference in scoping classification for the above piping sections.

In its response dated August 9, 2011, the applicant stated that license renewal drawing LR-STP-WL-7R309F90001#1 inadvertently omitted the depiction of the piping sections being within the scope of license renewal for 10 CFR 54.4(a)(2). By letter dated November 3, 2011, the applicant revised license renewal drawing LR-STP-WL-7R309F90001#1 to depict the six piping sections and components with red (10 CFR 54.4(a)(2)) highlighting.

Based on its review, the staff finds the applicant’s response to RAI 2.3.3.22-3, and the corrections to the scoping boundaries, acceptable because the applicant corrected the discrepancies in license renewal drawing LR-STP-WL-7R309F90001#1 and the corrected drawing appropriately depicts the piping sections and components within the scope of license renewal for 10 CFR 54.4(a)(2). By reviewing the revised license renewal boundary drawings, the staff confirmed that no new component types were added as a result of the RAI response. The RAI response added several valves and pipe sections to the scope of license renewal and subject to an AMR. Therefore, the staff’s concern described in RAI 2.3.3.22-3 is resolved.

In RAI 2.3.3.22-4, dated July 12, 2011, the staff noted license renewal drawing LR-STP-WL-7R309F90001#1 contains 10 CFR 54.4(a)(2) termination symbols. However, no pipe sections or equipment are identified as within the scope of license renewal. The staff requested that the applicant identify the pipe sections and any components that are within the scope of license renewal.

In its response dated August 9, 2011, the applicant stated that license renewal drawing LR-STP-WL-7R309F90001#1 inadvertently omitted the red (10 CFR 54.4(a)(2)) highlighting between the spatial interaction termination symbols for spatial interaction. By letter dated

November 3, 2011, the applicant revised license renewal drawing LR-STP-WL-7R309F90001#1 to include the six piping sections within the scope of license renewal for 10 CFR 54.4(a)(2).

Based on its review, the staff finds the applicant's response to RAI 2.3.3.22-4, and the corrections to the scoping boundaries, acceptable because the corrected license renewal drawing appropriately includes the piping sections and components in question within the scope of license renewal for 10 CFR 54.4(a)(2). Therefore, the staff's concern described in RAI 2.3.3.22-4 is resolved.

2.3.3.22.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and license renewal boundary drawings (original and revised) to determine whether the applicant identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the liquid waste processing system mechanical components within the scope of license renewal, as required by 10 CFR 54.5(a), and that the applicant 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 Radioactive Vents and Drains

2.3.3.23.1 Summary of Technical Information in the Application

LRA Section 2.3.3.23 describes the radioactive vents and drains system. The section states that the system is comprised of two subsystems—the radioactive drains subsystem and the radioactive vent header subsystem. The section also states that the purposes of the system are as follows:

- to collect and transport contaminated and potentially contaminated water from drains in several plant buildings and from the safety-related rooms for the safety injection and containment spray system pump rooms
- to provide leak detection for the safety injection and containment spray rooms
- to collect radioactive gasses from tanks and equipment locations for the purpose of monitoring and controlling releases through the plant main exhaust stack

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

LRA Table 2.3.3-23 contains a list of the component types subject to an AMR for the radioactive vents and drains system.

2.3.3.23.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.23, UFSAR Sections 6.2.4, 9.3.3, and Table 3.2.A-1, and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs, as discussed below.

In RAI 2.3.3.23-1, dated July 12, 2011, the staff noted that license renewal boundary drawings LR-STP-ED-50069F05030#1 and LR-STP-ED-50069F05030#2, coordinates A-7 and F-4, depict MAB elevator No. 5 sump pump 90061NPA115A and FHB sump No. 3 sump pump 90061NPA109A casing and discharge piping as not within the scope of license renewal. However, the same drawings depict similar sump pumps and their associated casings and discharge piping as within the scope of license renewal for 10 CFR 54.4(a)(2). The staff requested that the applicant provide the basis for excluding the pump casings and the discharge piping for pumps 9006NPA115A and 90061NPA109A from the scope of license renewal.

In its response dated August 9, 2011, the applicant explained that pumps 9006NPA115A and 90061NPA109A and associated piping are contained within rooms that do not contain safety-related components, so spatial interaction with safety-related components is not possible.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.3-01, and the explanations of the scoping boundaries, acceptable because the pumps are located in rooms with no safety-related equipment. Therefore, the staff's concern described in RAI 2.3.3.23-1 is resolved.

In RAI 2.3.3.23-2, dated July 12, 2011, the staff noted that license renewal boundary drawings LR-STP-ED-7Q069F90016#1 and LR-STP-ED-7Q069F90016#2, coordinates D-1, depict 3-inch pipe sections (ED1120TC7) within the scope of license renewal. The piping continues to license renewal boundary drawings LR-STP-ED-5Q069F05030#1 and LR-STP-ED-5Q069F05030#2, coordinates E-4, where they are shown as not within the scope of license renewal. The staff requested that the applicant provide the basis for the difference in scoping classification of these pipe sections.

In its response dated August 9, 2011, the applicant stated that the boundary drawings LR-STP-ED-5Q069F05030#1 and LR-STP-ED-5Q069F05030#2 correctly show spatial interaction terminations before the piping continues to drawings LR-STP-ED-7Q069F90016#1 and LR-STP-ED-7Q069F90016#2, and that the continuation piping on drawings LR-STP-ED-7Q069F90016#1 and LR-STP-ED-7Q069F90016#2 is incorrectly highlighted red for spatial interaction. The applicant explained that the classification change is because the piping exits a room with safety-related equipment and goes into a room without safety-related equipment. By letter dated November 3, 2011, the applicant corrected license renewal boundary drawings LR-STP-ED-7Q069F90016#1 and LR-STP-ED-7Q069F90016#2 to remove the continuation of drain piping ED1120TC7 from the scope of license renewal.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.23-2, and the corrections to the scoping boundaries, acceptable because the spatial interaction terminates when the piping transitions from the room with safety-related equipment to one without. The applicant corrected the license renewal boundary drawings LR-STP-ED-7Q069F90016#1 and LR-STP-ED-7Q069F90016#2 to remove from the scope of license renewal the pipe section continuations of ED1120TC7. Therefore, the staff's concern described in RAI 2.3.3.23-2 is resolved.

2.3.3.23.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and license renewal boundary drawings (original and revised) to determine whether the applicant identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the radioactive vents and drains system mechanical components within the scope of license renewal, as required by 10 CFR 54.5(a), and that the applicant adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.24 Nonradioactive Waste Plumbing Drains and Sumps

2.3.3.24.1 Summary of Technical Information in the Application

LRA Section 2.3.3.24 discusses the nonradioactive waste plumbing drains and sumps system. The LRA states that this system is nonsafety-related and that its purpose is to collect liquid nonradioactive waste from floor drains and sumps for processing or release. The LRA also states that this system does not provide any safety-related functions. The LRA also states that the system has features to prevent external floodwater from backflowing and intruding into the buildings it serves.

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(2) and (a)(3).

LRA Table 2.3.3-24 contains a list of the component types subject to an AMR for the nonradioactive waste plumbing drains and sumps system.

2.3.3.24.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.24 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.24.3 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 concludes that the applicant appropriately identified the nonradioactive waste plumbing drains and sumps system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.25 Oily Waste

2.3.3.25.1 Summary of Technical Information in the Application

LRA Section 2.3.3.25 discusses the oily waste system. The section states that its purpose is to handle oily waste and transfer it from several buildings and yard locations, such as the turbine building, the isolation valve cubicles building, the DGB, the MEAB, machine shop, yard transformer pits, and other locations. The LRA also states that these waste streams are transferred to the oily waste treatment facility, where oily substances are removed and release effluents are prepared for release within regulatory quality and concentration limits. The LRA states that the system has provisions so external flooding cannot intrude through it into the Category I structures it serves and that the oily waste system performs no safety-related functions.

The LRA classifies portions of the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(3).

LRA Table 2.3.3-25 contains a list of the component types subject to an AMR for the oily waste system.

2.3.3.25.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.25 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.25.3 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 concludes that the applicant appropriately identified the oily waste system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.26 Radiation Monitoring (Area and Process) Mechanical

2.3.3.26.1 Summary of Technical Information in the Application

LRA Section 2.3.3.26 describes the radiation monitoring (area and process) mechanical system and states that the purpose of this system is to record, monitor, and control release of radioactive materials in the areas or systems that it monitors. The LRA also states that this system provides ESF actuation signals to prevent or lessen radiological releases and accidents. The LRA states that parts of this system are safety-related and that portions of the system perform containment isolation functions.

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(2).

LRA Table 2.3.3-26 contains a list of the component types subject to an AMR for the radiation monitoring (area and process) mechanical system.

2.3.3.26.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.26, UFSAR Section 11.5, and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results.

In RAI 2.3.3.26-1, dated July 12, 2011, the staff noted that license renewal boundary drawings LR-STP-HE-5V119V250003#1 and LR-STP-HE-5V119V250003#2, coordinates F-5, D-5, and B-5, show carbon filter spray nozzles. The spray nozzle component type is not included in Table 2.3.3-26. The staff requested that the applicant provide the basis for excluding the spray nozzle component type from Table 2.3.3-26.

In its response dated August 9, 2011, the applicant stated the carbon filter spray nozzles are within the scope of license renewal and are already included in fire protection Table 2.3.3-17. The carbon filter spray nozzles are generic components with a component type of "piping" and an intended function of "spray."

Based on its review, the staff finds the applicant's response to RAI 2.3.3.26-1 acceptable because the carbon filter spray nozzles are already within the scope of license renewal for fire protection and are included in Table 2.3.3-17 as "piping." Therefore, the staff's concern described in RAI 2.3.3.26-1 is resolved.

2.3.3.26.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and license renewal boundary drawings (original and revised) to determine whether the applicant identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the radiation monitoring (area and process) mechanical system mechanical components within the scope of license renewal, as required by 10 CFR 54.5(a), and that the applicant 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 Miscellaneous Systems In-Scope Only for Criterion a(2)

2.3.3.27.1 Summary of Technical Information in the Application

LRA Section 2.3.3.27 discusses 13 miscellaneous mechanical systems (either nonsafety-related or with portions that are nonsafety-related) that are within the scope of license renewal only because they have the potential for causing adverse spatial interactions with safety-related systems or components, in accordance with 10 CFR 54.4(a)(2). The section briefly lists the purposes of these systems and explains why the applicant classified them as within the scope of license renewal. The systems are as follows:

- boron recycling
- condensate
- condensate storage
- essential cooling pond makeup
- gaseous waste processing
- low pressure nitrogen
- MAB plant vent header (radioactive)
- nonradioactive chemical waste
- open loop auxiliary cooling
- potable water and well water
- secondary process sampling
- solid waste processing
- turbine vents and drains

The LRA classifies the systems as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

LRA Table 2.3.3-27 contains a list of the component types subject to an AMR for these 13 miscellaneous mechanical systems.

2.3.3.27.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.27 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.27.3 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 concludes that the applicant appropriately identified the mechanical components of the miscellaneous systems in-scope only for criterion a(2) within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.28 Lighting Diesel Generator System

2.3.3.28.1 Summary of Technical Information in the Application

In its 2011 Annual Update to the LRA, the applicant added the lighting diesel generator system to the list of systems within the scope of license renewal as Section 2.3.3.28. The lighting diesel generator system is a mechanical system, and portions of the system support fire protection requirements, consistent with the criteria of 10 CFR 54.4(a)(3). The applicant described the purpose of the system as providing lighting to operator access routes to various safe-shutdown components requiring travel outside of buildings. The lighting diesel generator provides power to this lighting during a loss of offsite power.

The update included LRA Table 2.3.3-28, which contains a list of the component types subject to an AMR for mechanical components of this system. In addition, the update provided LRA Table 3.3.2-28, which provided a summary of aging management for the lighting diesel generator system.

2.3.3.28.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.28 and LRA Table 3.3.2.28 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.28.3 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 concludes that the applicant appropriately identified the mechanical components of the lighting diesel generator system within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4 Steam and Power Conversion Systems

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

- Section 2.3.4.1, "Main Steam"
- Section 2.3.4.2, "Auxiliary Steam System and Boilers"
- Section 2.3.4.3, "Feedwater"
- Section 2.3.4.4, "Demineralizer Water (Makeup)"
- Section 2.3.4.5, "Steam Generator Blowdown"
- Section 2.3.4.6, "Auxiliary Feedwater"
- Section 2.3.4.7, "Electrohydraulic Control"

2.3.4.1 Main Steam

2.3.4.1.1 Summary of Technical Information in the Application

LRA Section 2.3.4.1 describes the main steam system, and states that its purposes are as follows:

- to provide dry saturated steam from the steam generators to the secondary side steam components, such as the main turbine, the turbine-driven feedwater pumps, the turbine-driven AFW pumps, steam dump valves, atmospheric relief valves, code safeties, reheaters, and the auxiliary steam system
- to remove reactor heat (at power) and decay heat (when shutdown) from the RCS
- to provide containment isolation
- to provide overpressure protection

The LRA states that the system includes both safety-related and nonsafety-related components.

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

LRA Table 2.3.4-1 contains a list of the component types subject to an AMR for the main steam system.

2.3.4.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.1, UFSAR Section 10.3, and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs, as discussed below.

In RAI 2.3.4.1-1, dated July 12, 2011, the staff noted that license renewal boundary drawings LR-STP-MS-5S109F00016#1 and LR-STP-MS-5S109F00016#2, coordinates C-6, E-6, F-6, and H-6, depict piping downstream of the silencers as not within the scope of license renewal (a total of eight examples). These pipe sections appear to be part of the main steam system, which is depicted as being within the scope of license renewal for 10 CFR 54.4(a)(2). The staff requested that the applicant provide the basis of the scoping classification for these pipe sections.

In its response dated August 9, 2011, the applicant stated that the silencer piping both inside and outside the building is already included within the scope of license renewal but is inadvertently not shown as such on the drawings. By letter dated November 3, 2011, the applicant revised license renewal boundary drawings LR-STP-MS-5S109F00016#1 and LR-STP-MS-5S109F00016#2 to depict the piping downstream of the silencers with red (10 CFR 54.4(a)(2)) highlighting.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.1-1, and the classification of the components as being within the scope of license renewal, acceptable because the piping downstream of the silencers was corrected on the drawings as being within the scope of license renewal. By reviewing the revised license renewal boundary drawings, the staff confirmed that no other additional component types were added as a result of the RAI response. Additional piping was included in the scope of license renewal and subject to an AMR. Therefore, the staff's concern described in RAI 2.3.4.1-1 is resolved.

In RAI 2.3.4.1-2, dated July 12, 2011, the staff noted on license renewal boundary drawings LR-STP-MS-5S101Z51002 and LR-STP-MS-5S102Z51002, a listing of components of the main steam power operated relief valve-hydraulic system along the bottom of the drawings. However, the desiccant breather is not listed in LRA Table 2.3.4-1. The staff requested that the applicant provide the basis for excluding the desiccant breather component type from LRA Table 2.3.4-1.

In its response dated August 9, 2011, the applicant stated the desiccant breather is included in Table 2.3.4-1 as a component type "filter." The applicant also noted that the desiccant breather was inadvertently identified as steel versus stainless steel. By letter dated November 3, 2011, the applicant revised Table 3.4.2-1 to include a new "stainless steel filter with a lube oil internal environment and plant indoor air external environment."

Based on its review, the staff finds the response to RAI 2.3.4.1-2 acceptable because the applicant explained that the desiccant breather was included in Table 2.3.4-1 as a component type "filter." Therefore, it is within the scope of license renewal. The applicant also corrected the component type to stainless steel filter in Table 3.4.2-1. Therefore, the staff's concern described in RAI 2.3.4.1-2 is resolved.

2.3.4.1.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, revised Table 3.4.2-1, and license renewal boundary drawings (original and revised) to determine whether the applicant identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant 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 54.5(a), and that the applicant adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.2 Auxiliary Steam System and Boilers

2.3.4.2.1 Summary of Technical Information in the Application

LRA Section 2.3.4.2 describes the auxiliary steam system and boilers and states that this system's purposes are as follows:

- to provide steam to systems and components of both units during various operations, such as startup steam for the turbine plant deaerators, main turbine and feedwater pump seals, steam for operating the liquid waste processing system, and steam for the boron recycle system
- to provide sensors for detecting auxiliary steam line breaks and initiating steam line isolation to limit effects of a harsh environment for the equipment in those locations

The LRA also states that this system contains both safety-related and nonsafety-related components.

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

LRA Table 2.3.4-2 contains a list of the component types subject to an AMR for the auxiliary steam system and boilers.

2.3.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.2, UFSAR Section 9.5.9, and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results.

In RAI 2.3.4.2-1, dated July 12, 2011, the staff noted that license renewal drawing LR-STP-WL-5R309F05027#2, coordinates G-4, depicts piping 2"WL2586XC7 as being within the scope of license renewal pursuant to 10 CFR 54.4(a)(2). The piping continues to LR-STP-WL7R309F05026#2, coordinates E-6, where it is depicted as not within the scope of license renewal. The staff requested that the applicant provide the basis for the different scoping classifications for this pipe section.

In its response dated August 9, 2011, the applicant stated that license renewal drawing LR-STP-WL-5R309F05027#2 inadvertently omits a spatial interaction termination symbol at coordinates G-4 near the continuation for piping 2"WL2586XC7. The applicant stated that a portion of piping 2"WL2586XC7, which is depicted as being within scope of license renewal for 10 CFR 54.4(a)(2), exits an area with safety-related components and continues to an area with nonsafety-related components. The continuation license renewal drawing LR-STP-WL7R309F05026#2 depicts the nonsafety-related components. By letter dated November 3, 2011, the applicant revised license renewal drawing LR-STP-WL-5R309F05027#2 to include the spatial interaction termination symbol on piping 2"WL2586XC7 near the off-sheet connector.

Based on its review, the staff finds the response to RAI 2.3.4.2-1, and the corrections to the scoping boundary, acceptable because the applicant corrected the scoping discrepancy on piping 2"WL2586XC7, corrected the associated license renewal drawing by adding the missing spatial interaction termination symbol, and explained the scoping classification change due to the continuation piping being in an area with nonsafety-related components. Therefore, the staff's concern described in RAI 2.3.4.2-1 is resolved.

2.3.4.2.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI response, and license renewal boundary drawings (original and revised) to determine whether the applicant identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the auxiliary steam system and boilers mechanical components within the scope of license renewal, as required by 10 CFR 54.5(a), and that the applicant 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 Feedwater

2.3.4.3.1 Summary of Technical Information in the Application

LRA Section 2.3.4.3 discusses the feedwater system. The section states that the feedwater system's purposes are to deliver high-purity, high pressure feedwater to the steam generators using its booster pumps, turbine-driven feedwater pumps, and one motor-driven startup feedwater pump; to provide containment isolation; and to isolate feedwater to prevent excessive cooldowns and containment overpressures during secondary steam or feedwater line breaks.

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

LRA Table 2.3.4-3 contains a list of the component types subject to an AMR for the feedwater system.

2.3.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.3 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.4.3.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI response, and license renewal boundary drawings (original and revised) to determine whether the applicant identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant 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 54.5(a), and that the applicant adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.4 Demineralizer Water (Makeup)

2.3.4.4.1 Summary of Technical Information in the Application

LRA Section 2.3.4.4 describes the demineralizer water (makeup) system and states that it takes filtered service water treated with sodium hypochlorite, removes further ionic impurities, and supplies the resulting high-purity, demineralized water to both primary and secondary systems in the plant. The section states that this system also has containment isolation valves to provide containment integrity during accidents.

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(2).

LRA Table 2.3.4-4 contains a list of the component types subject to an AMR for the demineralizer water (makeup) system.

2.3.4.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.4, UFSAR Sections 9.2.3, 9.2.6, and 9.2.7, and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results.

In RAI 2.3.4.4-1, dated July 12, 2011, the staff noted that license renewal boundary drawings LR-STP-DW-5S199F05034#1 and LR-STP-DW-5S199F05034#2, coordinates B-6, depict 10 CFR 54.4(a)(2) piping 4"DW0018WD9 continuing to drawing LR-STP-NL-6S190F00009 coordinates E-2 and B-2, where the underground piping is shown as not within the scope of license renewal. The termination symbol "F.4.e," at coordinates B-6, is annotated to state that it indicates that all underground piping is within the scope of license renewal. Also, during the scoping and screening audit of May 16–19, 2011, the applicant indicated that there were similar instances in which portions of buried piping in other systems were removed from the scope of license renewal. The staff requested that the applicant provide the basis for not including the entire underground portion of the pipe section described above within the scope of license renewal. The staff also requested the applicant identify and provide the basis for the other portions of buried piping removed from the scope of license renewal.

In its response dated August 9, 2011, the applicant stated that the termination symbol and note for pipe 4"DW0018WD9 on boundary drawings LR-STP-DW-5S199F05034#1 and LR-STP-DW-5S199F05034#2 are incorrect, and that the point of entry to underground in the MEAB should be labeled as a spatial interaction termination; the applicant stated that this correction results in removing the underground portion from the scope of license renewal. The applicant also stated that, in February 2011, it re-evaluated all buried piping when implementing revised buried pipe requirements associated with the Generic Aging Lessons Learned (GALL) Report, Revision 2, AMP XI.M41. The applicant stated that this re-evaluation identified several sections of buried piping that were removed from the scope of license renewal. By letter dated November 3, 2011, the applicant revised license renewal boundary drawings LR-STP-DW-5S199F05034#1 and LR-STP-DW-5S199F05034#2 to remove this underground piping as being in-scope.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.4-1, and the deletion of the underground piping from the scope of license renewal, acceptable because the applicant corrected boundary drawings LR-STP-DW-5S199F05034#1 and LR-STP-DW-5S199F05034#2 to remove the incorrect "F.4.e" designation and included the spatial interaction symbol. The staff observed that spatial interaction terminates when pipe 4"DW0018WD9 goes underground in the MEAB. The staff also observed that the applicant re-evaluated piping in accordance with revised recommendations in the GALL Report, Revision 2, as applicable to its Buried Piping Program and determined that several sections of buried piping are no longer in-scope. Therefore, the staff's concern described in RAI 2.3.4.4-1 is resolved.

2.3.4.4.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI response, and license renewal boundary drawings (original and revised) to determine whether the applicant identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the demineralized water (make-up) system mechanical components within the scope of license renewal, as required by 10 CFR 54.5(a), and that the applicant adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.5 Steam Generator Blowdown

2.3.4.5.1 Summary of Technical Information in the Application

LRA Section 2.3.4.5 discusses the steam generator blowdown system. The section states that this system aids in maintaining secondary water chemistry by providing continuous blowdown from each steam generator. The LRA states that the blowdown also prevents buildup of corrosion products, reduces steam generator radioactivity levels, and provides a means to drain steam generator secondary sides. Finally, the LRA states that the sludge lancing and chemical cleaning subsystems are evaluated as part of the steam generator blowdown system.

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

LRA Table 2.3.4-5 contains a list of the component types subject to an AMR for the steam generator blowdown system.

2.3.4.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.5 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.4.5.3 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 concludes that 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). The staff also finds that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.6 Auxiliary Feedwater

2.3.4.6.1 Summary of Technical Information in the Application

LRA Section 2.3.4.6 describes the AFW system. The section states that the system takes water from the AFW storage tank and provides feedwater to the steam generators during startups, shutdowns, and emergency situations, using combinations of the two motor-driven and one turbine-driven AFW pumps. The LRA also states that the system provides decay heat removal from the RCS during shutdown and cooldown conditions.

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

LRA Table 2.3.4-6 contains a list of the component types subject to an AMR for the AFW system.

2.3.4.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.6, UFSAR Section 10.4.9, and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs, as discussed below.

In RAI 2.3.4.6-1, dated July 12, 2011, the staff noted that license renewal drawing LR-STP-AF-5S142F00024-1, coordinates H-7, depicts AFW pump No. 24 3S142MPA04 1-inch vent piping and associated isolation valves AF0129 and AF0130 as not within the scope of license renewal. However, the same drawing depicts the pump vent lines and associated isolation valves coordinates F-7, D-7, and B-7, for AFW pumps No. 21 3S142MPA01, No. 22 3S142MPA02, and No. 23 3S142MPA03 as within the scope of license renewal for 10 CFR 54.4(a)(1) or (a)(3). The staff requested that the applicant provide the basis for excluding pump No. 24 3S142MPA04 vent piping and associated isolation valves from the scope of license renewal.

In its response dated August 9, 2011, the applicant stated that the 1-inch vent piping and valves AF0129 and AF0130 were incorrectly depicted on license renewal drawing LR-STP-AF-5S142F00024-1 as being excluded from the scope of license renewal. By letter dated November 3, 2011, the applicant revised license renewal drawing LR-STP-AF-5S142F00024-1 to include AFW pump No. 24 3S142MPA04 1-inch vent piping and associated isolation valves AF0129 and AF0130 as being in-scope for license renewal.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.6-1, and the corrections to the scoping boundary, acceptable because the corrections to the license renewal drawing show the vent piping and associated isolation valves as being within the scope of license renewal consistent with the in-scope portions of AFW pumps No. 21 3S142MPA01, No. 22 3S142MPA02, and No. 23 3S142MPA03. Based on a review of the revised license renewal boundary drawings, the staff confirmed that no additional component types were added as a result of the response to the RAI. Some valves and piping were added to the scope of license renewal and made subject to aging management as a result of the response to the RAI. Therefore, the staff's concern described in RAI 2.3.4.6-1 is resolved.

In RAI 2.3.4.6-2, dated July 12, 2011, the staff noted that license renewal drawing LR-STP-AF-5S142F00024-1, coordinates H-7, F-7, D-7, and B-7, depict AFW pump 1-inch vent piping and associated isolation valves. However, Unit 1 license renewal drawing LR-STP-AF-5S141F00024-1, coordinates H-7, F-7, D-7, and B-7, do not include AFW pump vent piping details. The staff requested that the applicant confirm that there is no vent piping and associated isolation valves on the Unit 1 AFW pumps.

In its response dated August 9, 2011, the applicant stated there are no vent valves and associated vent piping installed on the Unit 1 AFW pumps, as confirmed by the STP Mechanical Equipment Database.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.6-2, and the explanation of the Unit 1 scoping boundary, acceptable because the applicant confirmed the absence of vent piping and isolation valves on the Unit 1 AFW pumps using its STP Mechanical Equipment Database. Therefore, the staff's concern described in RAI 2.3.4.6-2 is resolved.

In RAI 2.3.4.6-3, dated July 12, 2011, the staff noted that license renewal boundary drawings LR-STP-AF-5S141F00024-1 and LR-STP-AF-5S142F00024-1, coordinates G-7, depict the AFW pump turbine attached to the turbine-driven AFW pump, which are both within the scope of license renewal for 10 CFR 54.4(a)(1). However, the license renewal boundary drawings also depict piping in between the two components as not within the scope of license renewal. The staff requested that the applicant provide the basis for excluding the piping from the scope of license renewal.

In its response dated August 9, 2011, the applicant stated that the component was not piping but a mechanical shaft that connects the AFW pump turbine to its (turbine-driven) pump. The applicant further stated that this shaft was in-scope (for 10 CFR 54.4(a)(1)) and was incorrectly identified as not being within the scope of license renewal. By letter dated November 3, 2011, the applicant revised license renewal boundary drawings LR-STP-AF-5S141F00024-1 and LR-STP-AF-5S142F00024-1 to depict the shafts as being within the scope of license renewal.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.6-3, and the correction adding the mechanical connecting shafts to be within the scope of license renewal, acceptable because the shaft is integral to the pump but does not require aging management since it is a non-pressure boundary component. The applicant revised the license renewal boundary drawings to show the shafts as being within scope of license renewal for 10 CFR 54.4(a)(1). No other component types or components were added to the scope of license renewal as a result of the response to the RAI. Therefore, the staff's concern described in RAI 2.3.4.6-3 is resolved.

2.3.4.6.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and license renewal boundary drawings (original and revised) to determine whether the applicant identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the AFW system mechanical components within the scope of license renewal, as required by 10 CFR 54.5(a), and that the applicant 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 Electrohydraulic Control

2.3.4.7.1 Summary of Technical Information in the Application

LRA Section 2.3.4.7 describes the electrohydraulic control system and states that it provides the motive and control force for positioning turbine-generator steam throttle and stop valves to regulate steam flow through the main turbine and provides sensors that generate turbine trip signals as inputs to the reactor protection system and to ATWS circuitry. The LRA also states that this system does not provide any safety-related functions except for the trip signal inputs and that those trip signal components are evaluated with the plant's electrical equipment.

The LRA classifies the system as being within the scope of license renewal in accordance with 10 CFR 54.4(a)(3).

LRA Table 2.3.4-7 states that there are no mechanical component types subject to an AMR for the electrohydraulic control system.

2.3.4.7.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.7 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.4.7.3 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 concludes that the applicant appropriately identified the steam generator electrohydraulic control system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4 Scoping and Screening Results: Structures

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

- containment building
- control room
- diesel generator building
- turbine generator building
- mechanical-electrical auxiliary building
- miscellaneous yard areas and buildings (in scope)
- electrical foundations and structures
- fuel handling building
- essential cooling water structures
- auxiliary feedwater storage tank foundation and shell

- supports
- scoping and screening review of fire barriers

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 confirm that the applicant properly carried out its methodology, the staff's review focused on the implementation results. This focus allowed the staff to confirm that it did not omit any 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 whether the applicant has 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 confirm 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 had 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 whether the applicant omitted from the scope of license renewal components with intended functions delineated in 10 CFR 54.4(a). The staff also reviewed the licensing basis documents to determine whether the LRA specified all intended functions delineated in 10 CFR 54.4(a). The staff requested additional information to resolve any omissions or discrepancies.

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 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 evaluation of the structural scoping and screening results applies to all structures reviewed. Those structures that required RAIs in order to resolve any omissions, issues, or discrepancies include an additional staff evaluation that specifically addresses the applicant's response to the RAI(s).

2.4.1 Containment Building

2.4.1.1 Summary of Technical Information in the Application

In LRA Section 2.4.1, the applicant described the containment building as being a prestressed, reinforced concrete, cylindrical structure with a hemispherical dome roof. In addition, a continuously welded steel liner plate is anchored to the inside face of the containment shell. The foundation of the containment building consists of a reinforced concrete mat, circular in plan and having a uniform thickness. The cylinder and dome are post-tensioned with high-strength, unbonded wire tendons.

The containment building is a seismic Category I structure and its purpose is to limit the release of radioactive fission products and the resulting dose to the public and the control room operators. In addition, the containment building also provides physical support for itself, the

RCS, ESFs, and other systems and equipment within the structure. The exterior walls and dome provide shelter and protection for the RV and other safety-related SSCs.

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

The major structural components of the containment building are discussed as follows.

2.4.1.1.1 Post-tensioning System

The cylindrical portion and the hemispherical dome of the containment are prestressed by a post-tensioning system consisting of vertical and horizontal tendons. The cylinder and the lower half of the dome are prestressed by horizontal tendons anchored 360 degrees apart. Each successive hoop tendon is progressively offset 120 degrees from the one beneath it. These vertical U-shaped tendons are anchored in the gallery beneath the base mat.

2.4.1.1.2 Steel Liner Plate

A carbon steel liner plate that is continuously welded limits the release of radioactive materials into the environment and is provided on the inside face of the containment. The plate thickness is increased around all penetrations and for the crane girder brackets.

2.4.1.1.3 Other Penetrations

The containment pressure boundary also includes other penetrations such as the electrical penetrations, the piping penetrations, and the fuel transfer tube. All penetrations are pressure-resistant, leaktight, welded assemblies. The penetration sleeves are welded to the liner and anchored into the concrete containment wall.

2.4.1.1.4 Internal Structures

The containment internal structures are designed to provide structural supporting elements for the major components of the nuclear steam supply system (NSSS) as well as to provide required shielding, both against internal missiles and for biological protection. The internal structures consist of the primary shield wall, the secondary shield wall, the refueling cavity, the operating floor, the intermediate floors, the interior fill slab, the polar crane, structural and miscellaneous steel, and removable concrete block walls.

2.4.1.1.5 Containment Sump and Trisodium Phosphate Basket

Following a large break LOCA, the containment spray water and spilled RCS water will be routed to the containment sump. TSP stored in stainless steel baskets on the containment floor will be dissolved, and the alkaline fluid will be recirculated to reduce the concentration and quantity of fission products in the containment atmosphere.

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 confirm that the applicant has included in the scope of license renewal all SCs with intended functions delineated in 10 CFR 54.4(a).

The staff then reviewed those SCs that the applicant included as within the scope of license renewal to confirm that the applicant has included all 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 2.4.1, 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 insufficient information was provided regarding the fire stops for cable trays. By letter dated April 14, 2011, the staff issued RAI 2.4.1-1, requesting that the applicant provide additional information regarding where the LRA addresses these fire stops. In addition, the staff requested that if the fire stops are subject to an AMR, the applicant should identify the applicable aging effects and the AMP related to these components.

By letter dated May 5, 2011, the applicant responded that the fire stops installed in cable trays at fire barrier penetrations are evaluated within the component type "fire barrier seals." Specifically, the LRA Tables 2.4-2, 2.4-3, 2.4-4, 2.4-5, 2.4-6, 2.4-8, and 2.4-9 include fire stops as components within the scope of license renewal and subject to an AMR. The applicant also stated that LRA Tables 3.5.2-2, 3.5.2-3, 3.5.2-4, 3.5.2-5, 3.5.2-6, 3.5.2-8, and 3.5.2-9 identify the Fire Protection Program (B2.1.12) as the AMP that manages the aging of "fire barrier seals."

Based on its review, the staff finds that the applicant adequately clarified the LRA section that addresses fire stops for cable trays in-scope for license renewal and confirmed that there is an AMP to manage the aging effects of the component. Therefore, the staff finds the applicant's response to RAI 2.4.1-1 acceptable. The staff's concern described in RAI 2.4.1-1 is resolved.

By letter dated April 14, 2011, the staff issued RAI 2.4.1-2, requesting that the applicant provide additional information regarding the spray-applied fireproofing material used in exposed structural steel, as described in UFSAR Section 9.5.1, that could clarify the differences, similarities, or both, between this type of fire retardant and the fire retardant coatings described in RAI 2.4.1-1.

By letter dated May 5, 2011, the applicant responded that the terms "fire–retardant coatings" and "spray-applied fireproofing material" both refer to cementitious fireproofing that is applied to the structural steel components. The fireproofing material is included in and evaluated with the component type "fire barrier coatings and wraps" in LRA Tables 2.4-1, 2.4-2, 2.4-5, 2.4-8 as components within the scope of license renewal and subject to an AMR. The applicant also stated that LRA Tables 3.5.2-1, 3.5.2-2, 3.5.2-5, and 3.5.2-8 identify the Fire Protection Program (B2.1.12) as the AMP that manages the aging of "fire barrier coatings and wraps."

Based on its review, the staff finds that the applicant adequately clarified the differences and similarities between "fire–retardant coatings" and "spray-applied fireproofing material" and the location in the LRA where they are covered. Therefore, the staff finds the applicant's response to RAI 2.4.1-2 acceptable. The staff's concern described in RAI 2.4.1-2 is resolved.

2.4.1.3 Conclusion

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

2.4.2 Control Room

2.4.2.1 Summary of Technical Information in the Application

In LRA Section 2.4.2, the applicant described the control room as physically located in the MEAB, which is a multistory, structural steel, and reinforced concrete structure. The structure is supported by a reinforced concrete basemat and is categorized as a seismic Category I structure. For license renewal scoping and screening purposes, the control room includes the pressure boundary and all components inside this boundary. The license renewal boundary envelope encompasses the control room on the 35 ft elevation of the MEAB between columns 20 and 24 and A and H and HVAC rooms at the 10 ft and 60 ft elevations. This envelope provides a protected environment for essential plant personnel and SSCs.

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

2.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2 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 confirm that the applicant included in the scope of license renewal all SCs with intended functions delineated in 10 CFR 54.4(a).

The staff then reviewed those SCs that the applicant has included as within the scope of license renewal to confirm that the applicant has included all 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 2.4.2, 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 April 14, 2011, the staff issued RAI 2.4.2-1, requesting that the applicant provide information regarding the inclusion of aluminum sheathing that may house fire detection, lighting, and communication circuits in the control room, as stated in UFSAR Section 9.5.1, in the scope of license renewal. The staff also requested that the applicant specify the structures within the scope of license renewal that contain the aforementioned aluminum sheathing, the location within the LRA where it is addressed, and the corresponding AMP for this component type.

By letter dated May 5, 2011, the applicant responded that the aluminum sheathing is included and evaluated with the component type "conduit and supports" in LRA Table 2.4-11 and Table 2.4-12 as components within the scope of license renewal and subject to an AMR. The "aluminum" component is exposed to the environment "plant indoor air (structural)." LRA Table 3.5.2-11 identifies this component type. However, the GALL Report, line III.B2-4, specifies that for the combination described as component/material/environment, there is no applicable aging effect and, therefore, this combination does not require aging management.

Based on its review, the staff finds that the applicant's response to RAI 2.4.2-1 adequately clarified the inclusion of the aluminum sheathing within the scope of license renewal and the location of the evaluation in the LRA. In addition, the response clarified that based on the material-environment combination, an AMR is not included per the GALL Report, line III.B2-4. Therefore, the staff finds the applicant's response to RAI 2.4.2-1 acceptable. The staff's concern described in RAI 2.4.2-1 is resolved.

By letter dated April 14, 2011, the staff issued RAI 2.4.2-2, requesting that the applicant provide additional information regarding the dual 9-inch water stops located in all seismic joints between Category I structures that can withstand potential seismic and hydrostatic effects and that are credited for flood protection per UFSAR Section 3.4.1.

By letter dated May 5, 2011, the applicant responded that the water stops between Category I structures with the "flood barrier" intended function are included and evaluated with the component type "caulking and sealant" in LRA Tables 2.4-3, 2.4-5, 2.4-7, 2.4-8, 2.4-9, and 2.4-10 as components within the scope of license renewal and subject to an AMR. In addition, LRA Tables 3.5.2-3, 3.5.2-5, 3.5.2-7, 3.5.2-8, 3.5.2-9, and 3.5.2-10 identify the Structures Monitoring Program (B2.1.32) as the AMP that manages the aging of "caulking and sealant."

Based on its review, the staff finds that the applicant's response to RAI 2.4.2-2 adequately clarified the inclusion of the dual 9-inch water stops located in all seismic joints between Category I structures as components within the scope of license renewal and subject to an AMR. Therefore, the staff finds the applicant's response to RAI 2.4.2-2 acceptable. The staff's concern described in RAI 2.4.2-2 is resolved.

2.4.2.3 Conclusion

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

2.4.3 Diesel Generator Building

2.4.3.1 Summary of Technical Information in the Application

In LRA Section 2.4.3, the applicant described the DGB as a multistory, reinforced concrete structure that houses the emergency diesel generators, diesel oil tanks, and the intake and exhaust equipment. The structure is supported by a reinforced concrete basemat founded on engineered structural backfill and is categorized as a Seismic Category I structure. In addition, the roof consists of a reinforced concrete slab supported by reinforced concrete bearing walls. Three emergency diesel generators and diesel auxiliaries are separated by a reinforced concrete barrier wall.

LRA Table 2.4-3 identifies the components subject to an AMR for the DGB by component type and intended function.

2.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.4.3 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 confirm that the applicant included in the scope of license renewal all SCs with intended functions delineated in 10 CFR 54.4(a).

The staff then reviewed those SCs that the applicant has included as within the scope of license renewal to confirm that the applicant has included all 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 2.4.3, 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 April 14, 2011, the staff issued RAI 2.4.3-1, requesting that the applicant provide additional information regarding the particular configuration and components located in the diesel fuel oil filtration skid, listed as building #73 in drawing LR-STP-STRUC-9Y100M00001, Revision 15. In addition, since the building is not in scope for license renewal, the applicant was requested to provide a brief explanation on why the failure of this structure would not prevent satisfactory accomplishment of any of the functions performed by the diesel generators.

By letter dated May 5, 2011, the applicant responded to RAI 2.4.3-1 and stated that the diesel fuel oil filtration skid is a low-level steel and concrete structure that provides anchorage for filters and other equipment used to process fuel oil being transferred from other locations, such as from the auxiliary fuel storage and transfer system or from fuel trucks, to the diesel fuel oil storage tanks inside the DGB. The applicant also stated that the fuel oil storage tanks inside the DGB are designed to provide fuel oil supply to the standby diesel generators without replenishment from either the auxiliary fuel storage and transfer system or fuel trucks. The applicant concluded that there are no SSCs associated with the diesel fuel oil filtration skid whose failure could prevent satisfactory accomplishment of any of the functions performed by the standby diesel generators.

Based on its review, the staff finds that the applicant's response to RAI 2.4.3-1 adequately clarified the particular configuration and components located inside the diesel fuel oil filtration skid and provided additional information regarding the function of the structure that clarified it does not have a license renewal intended function and is therefore not within the scope of license renewal. Therefore, the staff finds the applicant's response to RAI 2.4.3-1 acceptable. The staff's concern described in RAI 2.4.3-1 is resolved.

By letter dated April 14, 2011, the staff issued RAI 2.4.3-2, requesting that the applicant provide additional information related to the three maintenance knockout panels in the exterior walls of the DGB, as described in the "Flood Protection" section in the STP UFSAR Section 3.4.1. Specifically, Table 2.4-3 only credited "caulking and sealant," "concrete elements," and "doors" as being credited with the "flood barrier" intended function, and did not include knockout panels.

By letter dated May 5, 2011, the applicant responded that the knockout panels are included in and evaluated with the component type "hatches and plugs" in LRA Table 2.4-3 as components within the scope of license renewal and subject to an AMR. LRA Table 3.5.2-3 identifies the Structures Monitoring Program (B2.1.32) as the AMP that manages the aging of "hatches and plugs." However, the intended function "Flood Barrier" was not included as an intended function within the component type “hatches and plugs” in LRA Table 2.4-3 or Table 3.5.2-3. Therefore, the applicant revised LRA Table 2.4-3 and Table 3.5.2-3 and added the intended function “Flood Barrier” to the component type “hatches and plugs.”

In reviewing the applicant’s response to RAI 2.4.3-2, the staff found that the applicant adequately covered the review of the three knockout panels described in STP UFSAR Section 3.4.1 and credited for “Flood Protection” under the component type “hatches and plugs” in LRA Tables 2.4-3 and 3.5.2-3. In addition, the applicant revised Tables 2.4-3 and 3.5.2-3 and added the intended function “Flood Barrier” to the component type “hatches and plugs.” Finally, the applicant has adequately identified the Structures Monitoring Program (B2.1.32) as the AMP that manages the aging of “hatches and plugs.” Based on its review, the staff finds the applicant’s response to RAI 2.4.3-2 acceptable. The staff’s concern described in RAI 2.4.3-2 is resolved.

2.4.3.3 Conclusion

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

2.4.4 Turbine Generator Building

2.4.4.1 Summary of Technical Information in the Application

In LRA Section 2.4.4, the applicant described the turbine generator building (TGB) as a semi-open, three-level steel structure supported on either an individual or combined mat or pedestal-and-mat reinforced concrete foundations. The TGB houses the turbine generator, steam generator feed pumps, feedwater heaters, electrical switchgear, air compressors, and other miscellaneous equipment. The TGB and the deaerator structure located on the east side of the building are in close proximity to the Category I isolation valves cubicle, MEAB, and DGB. However, non-Category I structures located near Category I SSCs have been designed either to withstand tornado loads or not to collapse against Category I structures under tornado loadings.

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

2.4.4.2 Staff Evaluation

The staff reviewed LRA Section 2.4.4 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. The staff’s review did not identify the need for any additional information.

2.4.4.3 Conclusion

Based on the results of the staff evaluation discussed in Section 2.4, and on a review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the TGB SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the SCs subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.5 Mechanical-Electrical Auxiliary Building

2.4.5.1 Summary of Technical Information in the Application

In LRA Section 2.4.5, the applicant described the MEAB as a Seismic Category I structure that houses the mechanical equipment, electrical equipment, and the isolation valve cubicle. The three areas in the multistory structure are separated by reinforced concrete walls and supported on a common foundation mat.

The mechanical section of the building (called the MAB) houses and supports the ESF systems, waste processing systems, piping systems, and the auxiliary equipment. The electrical section of the building (called the EAB) houses and supports the Class 1E electrical controls, switchgear, battery room, computer room, and cable raceways. In addition, the control room is located in the EAB, but it is evaluated separately in Section 2.4.2. The isolation valve cubicles section of the building houses four isolation valve cubicles.

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

2.4.5.2 Staff Evaluation

The staff reviewed LRA Section 2.4.5 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. The staff's review did not identify the need for any additional information.

2.4.5.3 Conclusion

Based on the results of the staff evaluation discussed in Section 2.4, and on a review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the MEAB SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the SCs subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.6 Miscellaneous Yard Areas and Buildings (In-Scope)

2.4.6.1 Summary of Technical Information in the Application

In LRA Section 2.4.6, the applicant described the miscellaneous yard areas and buildings as including the following structures:

- east gate house
- fire pump house
- fire water storage tanks foundation
- fire water valve structure
- lighting diesel generator building and tank building

The fire pump house is described as a metal building with a sheet metal roof on a concrete foundation that houses three fire pumps, each separated by reinforced concrete walls. The fire water storage tanks foundations are described as reinforced concrete ring foundations. The fire water storage tanks are evaluated separately with their respective system. Finally, the fire water valve structures are metal buildings with sheet metal roofing on a concrete foundation. There are three valve structures per unit. In its 2011 Annual Update, dated November 30, 2011, the applicant added two miscellaneous yard structures within the scope of license renewal, the east gate house and the lighting diesel generator building and tank building. The east gate house is described as a steel framed building with a metal roof and a concrete foundation that houses administrative offices and various mechanical and electrical support systems. The lighting diesel generator building and tank building are masonry buildings with metal roofs and concrete foundations that house the lighting diesel generator, diesel fuel supply tank, and various mechanical and electrical support systems.

LRA Table 2.4-6 identifies the components subject to an AMR for the miscellaneous yard areas and buildings within license renewal by component type and intended function.

2.4.6.2 Staff Evaluation

The staff reviewed LRA Section 2.4.6 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. The staff's review did not identify the need for any additional information.

2.4.6.3 Conclusion

Based on the results of the staff evaluation discussed in Section 2.4, and on a review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the miscellaneous yard areas and buildings SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the SCs subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.7 Electrical Foundations and Structures

2.4.7.1 Summary of Technical Information in the Application

In LRA Section 2.4.7, the applicant described the electrical foundations and structures as the foundations for the main, auxiliary, and standby transformers. They are comprised of reinforced concrete pads founded on undisturbed soil, engineered structural backfill, or both. In addition, the outdoor switchgear in the 345 kV switchyard, and all equipment from the main and standby transformers up to the first circuit breakers in the 345 kV switchyard, are supported on reinforced concrete pads founded on undisturbed soil, engineered structural backfill, or both.

The switchyard control building is a single story metal-sided structure with a sheet metal roof supported by a reinforced concrete foundation on structural backfill. In addition, all of the transmission towers up to the first circuit breakers in the 345 kV switchyard are founded on reinforced concrete bases supported on undisturbed soil, engineered structural backfill, or both.

The Class 1E underground electrical raceway system that provides electrical distribution from the MEAB to the essential cooling water intake structure (ECWIS) consists of banks of polyvinyl chloride conduits in a spaced arrangement encased in reinforced concrete. However, there are manholes provided along these duct banks for cable installation and access.

In its 2011 annual update, the applicant identified in the scope of license renewal the yard lighting that is mounted on high mast steel poles founded on reinforced concrete bases, which are supported on undisturbed soil and/or engineered structural backfill.

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

2.4.7.2 Staff Evaluation

The staff reviewed LRA Section 2.4.7 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. The staff's review did not identify the need for any additional information.

2.4.7.3 Conclusion

Based on the results of the staff evaluation discussed in Section 2.4 and on a review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the electrical foundations and structures SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the SCs subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.8 Fuel Handling Building

2.4.8.1 Summary of Technical Information in the Application

In LRA Section 2.4.8, the applicant described the FHB as a multistory, structural steel, and reinforced concrete structure that is supported on a reinforced concrete basemat founded on structural backfill in some areas and in-situ soil in the remaining areas. It is a Seismic Category I structure. The FHB houses new fuel, spent fuel, fuel shipping container and cask, spent fuel pool heat exchanger, spent fuel pool pumps, skimmer pumps, low-head and high-head safety injection pumps, containment spray pumps, and the valve isolation tank. In addition, the applicant describes the spent fuel pool and fuel transfer canals as being lined with a stainless steel plate with a leak detection system behind the liner.

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

2.4.8.2 Staff Evaluation

The staff reviewed LRA Section 2.4.8 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. The staff's review did not identify the need for any additional information.

2.4.8.3 Conclusion

Based on the results of the staff evaluation discussed in Section 2.4 and on a review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the FHB SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the SCs subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.9 Essential Cooling Water Structures

2.4.9.1 Summary of Technical Information in the Application

In LRA Section 2.4.9, the applicant described the ECW structures as being comprised of the essential cooling water pond (ECP), ECWIS, and ECW discharge structure. The intake and discharge structures are classified as safety-related, Seismic Category I, reinforced concrete structures. In addition, the intake and discharge structures are founded on engineered structural backfill. The ECP is a Seismic Category I, man-made excavated pond with an embankment completely surrounding its perimeter. The applicant also stated that all of the cooling water structures are common to Units 1 and 2. The ECWIS houses the ECW pumps. The ECP provides the required cooling water for ultimate heat sink and provides the normal heat sink for plant auxiliaries.

LRA Table 2.4-9 identifies the components subject to an AMR for the ECW structures SCs within license renewal by component type and intended function.

2.4.9.2 Staff Evaluation

The staff reviewed LRA Section 2.4.9 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 confirm that the applicant included in the scope of license renewal all SCs with intended functions delineated in 10 CFR 54.4(a).

The staff then reviewed those SCs that the applicant has included as within the scope of license renewal to confirm that the applicant has included all 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 2.4.9, 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 April 14, 2011, the staff issued RAI 2.4.9-1, requesting that the applicant provide additional information related to debris prevention/removal mechanisms that are part of the ECWIS, such as strainers, trash racks, and traveling screens. These debris prevention/removal mechanisms are listed in STP UFSAR Section 3.8.4.1.4 but are not listed in LRA Table 2.4-9 as being in scope for license renewal, as required by 10 CFR 54.4(a), and subject to an AMR, as required by 10 CFR 54.21(a)(1).

By letter dated May 5, 2011, the applicant responded that the trash racks are included in and evaluated with the component type "structural steel" in LRA Table 2.4-9 as components within the scope of license renewal and subject to an AMR. LRA Table 3.5.2-9 identifies the Structures Monitoring Program (B2.1.32) as the AMP that manages the aging of "structural steel." In addition, the applicant stated that the strainers and traveling screens are included in and evaluated with the component types "strainer element" and "traveling screen," respectively, in LRA Table 2.3.3-4 for the ECW and the ECW screen wash system as components within the scope of license renewal and subject to an AMR. LRA Table 3.3.2-4 identifies the Open-Cycle Cooling Water System (B2.1.9) as the AMP that manages the aging of "strainer elements" and "traveling screens."

Based on its review, the staff finds that the applicant's response to RAI 2.4.9-1 adequately addressed the review of the debris prevention/removal mechanisms that are part of the ECWIS listed in STP UFSAR Section 3.8.4.1.4. The trash racks, strainers, and traveling screens are included in-scope of license renewal and evaluated within the appropriate AMP, as stated above. Therefore, the staff finds the applicant's response to RAI 2.4.9-1 acceptable. The staff's concern described in RAI 2.4.9-1 is resolved.

2.4.9.3 Conclusion

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

2.4.10 Auxiliary Feedwater Storage Tank Foundation and Shell

2.4.10.1 Summary of Technical Information in the Application

In LRA Section 2.4.10, the applicant described the AFW foundation and shell as a reinforced concrete, Seismic Category I structure with cylindrical walls covered by a circular slab. In addition, the tank shell is supported by a circular concrete mat foundation, which bears on structural backfill. A reinforced concrete valve room is attached to the foundation mat.

LRA Table 2.4-10 identifies the components subject to an AMR for the AFW foundation and shell SCs within license renewal by component type and intended function.

2.4.10.2 Staff Evaluation

The staff reviewed LRA Section 2.4.10 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. The staff's review did not identify the need for any additional information.

2.4.10.3 Conclusion

Based on the results of the staff evaluation discussed in Section 2.4, and on a review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the AFW storage tank foundation and shell SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the SCs subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.11 Supports

2.4.11.1 Summary of Technical Information in the Application

In LRA Section 2.4.11, the applicant described the supports as structural supports for mechanical and electrical components that are evaluated as commodities across system boundaries. The commodity evaluation applies to structural supports within structures identified as being in the scope of license renewal. They are identified by characteristics of the supports, such as design, materials of construction, environments, and anticipated stressors.

The following structural supports for mechanical components are addressed:

- supports for American Society of Mechanical Engineers (ASME) Code Class 1 piping and components
- supports for ASME Code Class 2 and 3 piping and components
- supports for HVAC ducts, tube track, instrument tubing, instruments, and non-ASME Code piping and components

The following electrical components and supports are addressed:

- cable trays and supports
- conduit and supports
- electrical panels and enclosures
- instrument panels and racks

In addition, the applicant described that the structural support evaluation boundaries are based upon the following:

- Integral attachments (such as plate welded to pipe at anchor points, saddles welded to heat exchangers, etc.) are evaluated with the specific component (pipe, pump, heat exchanger, etc.).
- All pins, bolting, and other removable hardware that are part of the connection to component integral attachments are evaluated with the structural support, except high strength bolts for Class 1 NSSS supports, which are evaluated separately.
- The exposed portions of embedded components (i.e., end portion of the threaded anchor and nut) are evaluated with the component supports, except high strength bolts for Class 1 NSSS supports, as noted above.
- Concrete and supporting structural hardware (including the embedded portion of threaded anchors) are evaluated with the structure. The concrete around anchorages must be evaluated with the supports to identify any concrete degradation that would impair the function of the anchors. This package includes a separate component for the anchorage concrete for in-scope mechanical and electrical components in each building.

Finally, the applicant stated that the following RCS component supports are included with the ASME Code Class 1 piping and component commodity group:

- RV supports
- steam generator supports (vertical, lower lateral and upper lateral)
- reactor coolant pump supports
- pressurizer supports

LRA Table 2.4-11 identifies the components subject to an AMR for the supports SCs within license renewal by component type and intended function.

2.4.11.2 Staff Evaluation

The staff reviewed LRA Section 2.4.11 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. The staff's review did not identify the need for any additional information.

2.4.11.3 Conclusion

Based on the results of the staff evaluation discussed in Section 2.4, and on a review of the LRA and UFSAR, the staff concludes that the applicant appropriately identified the supports SCs within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant adequately identified the SCs subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.12 Scoping and Screening Review of Fire Barrier Portions of Structures

2.4.12.1 Summary of Technical Information in the Application

LRA Sections 2.4.1, 2.4.4, 2.4.8, and 2.4.9 contain descriptions of the containment building, the TGB, the FHB, and ECW structures. This information is presented and evaluated in SER Sections 2.4.1, 2.4.4, 2.4.8, and 2.4.9. The review in this section covers the staff evaluation of the fire barrier portions of these buildings and structures.

2.4.12.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.17, the UFSAR, and LRA drawings using the evaluation methodology described in SER Section 2.3 and guidance in the SRP-LR Section 2.3. The staff also reviewed UFSAR Section 9.5.1 and "Fire Protection Evaluation and Comparison to BTP APCSB 9.5-1, Appendix A Report," (i.e., approved Fire Protection Program) a point-by-point comparison with Appendix A to 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 South Texas Project Facility Operating Licenses for Unit 1 and Unit 2, Condition 2.E, "Fire Protection," NUREG-0781, dated April 1986, and its supplements.

During its review, the staff evaluated the system functions described in the LRA and UFSAR to confirm that the applicant had included in the scope of license renewal all 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 confirm that the applicant had included all passive or long-lived components subject to an AMR in accordance with 10 CFR 54.21(a)(1).

During its review of LRA Section 2.4, the staff identified areas in which additional information was necessary to complete its review of the applicant's scoping and screening results.

In its letter dated April 14, 2011, the staff issued RAI 2.4-1, stating that Section 2.4 of the LRA does not include the following fire barrier and fire barrier components in the respective LRA tables:

- Table 2.4-1: fire barrier seals
- Table 2.4-4: concrete elements, concrete wall (masonry walls)

- Table 2.4-8: fire barrier doors
- Table 2.4-9: fire barrier coatings

The fire barrier components listed above appear to have fire protection intended functions required for compliance with 10 CFR 50.48, as stated in 10 CFR 54.4. The staff requested that the applicant confirm whether the above fire barrier assemblies and fire protection components are within the scope of license renewal within the identified structure 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 requested that the applicant provide justification for the exclusion.

In a letter dated May 12, 2011, the applicant responded to RAI 2.4-1 and provided the following extra details:

- The reactor containment building is made up of a single fire area; the zones are present for administrative purposes only. No fire barrier seals are being credited for performing a fire barrier function in the containment building (LRA Table 2.4-1).
- Fire barrier concrete elements and concrete block (masonry walls) are being credited for performing fire barrier functions in the turbine building. Component type "concrete block walls (masonry wall)" has been added to LRA Table 2.4-4, Section 3.5.2.1.4, and LRA Table 3.5.2-4.
- Fire barrier doors are being credited for performing fire barrier functions in the FHB. Component type "fire barrier doors" has been added to LRA Tables 2.4-8 and 3.5.2-8.
- No fire barrier coatings or wraps in the ECW structure have been credited as performing a fire barrier intended function.

The staff reviewed the applicant's responses to RAI 2.4-1 and determined that the applicant had addressed each item in the RAI. The staff's concerns expressed in RAI 2.4-1 are resolved.

2.4.12.3 Conclusion

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

2.5 Scoping and Screening Results: Electrical Systems/Commodity Groups

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

In accordance with the requirements of 10 CFR 54.21(a)(1), the applicant must list passive, long-lived SSCs within the scope of license renewal and subject to an AMR. To confirm 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 whether the applicant has identified components and supporting structures for electrical and I&C systems that appear to meet the license renewal scoping criteria in accordance with 10 CFR 54.4. Similarly, the staff evaluated the applicant's screening results to confirm 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 and the RAI response, focusing on components that have not been identified as within the scope of license renewal. The staff reviewed the UFSAR for each electrical and I&C system to determine whether the application included in the scope of license renewal all components with intended functions delineated in 10 CFR 54.4(a).

After its review of the scoping results, the staff evaluated the applicant's screening results. For those SSCs with intended functions, the staff sought to determine whether: (a) the functions are performed with moving parts or a change in configuration or properties; or (b) the SSCs 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 SSCs were subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.5.1 Electrical and Instrumentation and Controls Systems

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 spaces approach for the review of plant equipment eliminates the need to associate electrical and I&C components with specific systems that are within the scope of license renewal. This approach groups all electrical and I&C components in component types and identifies the passive in-scope electrical component types that are subject to an AMR by applying the criteria of 10 CFR 54.21(a)(1)(i) and (a)(1)(ii). The SSCs in the SBO recovery path that are within the scope of license renewal are identified based on their compliance with 10 CFR 50.63. Components interfacing with the electrical and I&C components are assessed in the appropriate mechanical or structural sections. LRA Table 2.5-1 identifies electrical and I&C component types subject to an AMR and their intended functions within the scope of license renewal:

- cable connections (metallic parts)—electrical continuity
- connector—electrical continuity
- high-voltage insulator—expansion/separation, insulate (electrical), structural support
- insulated cable and connections—electrical continuity, insulate (electrical)
- metal enclosed bus (bus and connections)—electrical continuity
- metal enclosed bus (enclosure)—expansion/separation, structural support
- metal enclosed bus (insulation and insulators)—insulate (electrical)
- switchyard bus and connections—electrical continuity
- transmission conductors and connections—electrical continuity

2.5.1.2 Staff Evaluation

The staff reviewed LRA Section 2.5 and STP UFSAR Chapters 7 and 8 using the evaluation methodology described above and documented 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 confirm that the applicant included in the scope of license renewal all components with intended functions delineated in 10 CFR 54.4(a). The staff then reviewed those components that the applicant has identified as within the scope of license renewal to confirm that the applicant has included all 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 guidance provided by letter dated April 1, 2002 (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 stated the following:

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

In RAI 2.5-2, dated April 14, 2011, the staff requested the applicant to provide justification for why the control circuits and structures associated with the switchyard circuit breakers used to supply the SBO recovery paths are not within the scope of license renewal. In its response to RAI 2.5-2, by letter dated May 5, 2011, the applicant stated that the control circuits are not required for SBO recovery because the switchyard circuit breakers used to supply the SBO recovery paths remain in a closed position when offsite power is interrupted and that they (the circuit breakers) contain stored energy in order to be operated without the use of control circuits.

The staff referred the applicant to its position in SRP-LR Section 2.5.2.1.1, which states that control circuits associated with SBO recovery path breakers, regardless of whether those breakers are closed manually or remotely, should be included within the scope of license renewal. Therefore, the staff issued followup RAI 2.5-2a, by letter dated October 11, 2011, requesting that the applicant address this issue. By letter dated November 21, 2011, the applicant responded to RAI 2.5-2a and revised its position. The applicant stated that the switchyard breakers and switchyard breaker control cables and connections are (now) within the scope of license renewal. The staff reviewed the LRA and confirmed that the control cables and connections are included in the LRA tables for aging management evaluation. In addition, the applicant stated that the Structures Monitoring Program will be revised to clarify that the switchyard control building is part of the electrical foundations and structures, and it will be included in the AMP. The staff reviewed the applicant's November 21, 2011, letter and confirmed that the applicant included the switchyard control building as part of its components that provide structural support for SSCs required for SBO recovery. Furthermore, the staff confirmed that the applicant added a new regulatory commitment to the LRA to include the switchyard control building into the scope of the Structures Monitoring Program.

The applicant included within the scope of license renewal the complete circuits between the ESF 13.8 kV buses up to and including the circuit breakers of the 345 kV switchyard supplying the main and unit auxiliary transformers and the standby transformers. The circuit from the 345 kV switchyard circuit breakers Y510 and Y520 (Unit 1) and Y590 and Y600 (Unit 2) to the ESF buses is through the main and unit auxiliary transformers, which connect to the switchyard circuit breakers via disconnects G019 (Unit 1) and G029 (Unit 2). The circuit from the 345 kV switchyard north (Unit 1) and south (Unit 2) buses to the ESF buses is through the standby transformers 1 and 2, which connect to the switchyard north and south via disconnects S014 (Unit 1) and S024 (Unit 2). The switchyard's breakers, breaker control cables and connections, and disconnects are within the scope of license renewal. 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 and uninsulated grounding conductors in the component groups subject to an AMR because the applicant determined that the cable tie wraps and the uninsulated grounding conductors do not perform any license renewal functions, and their failure would not prevent any safety-related equipment from performing its intended function. The staff reviewed the UFSAR and found that cable tie wraps and uninsulated grounding conductors are not credited in the STP's design basis. Therefore, the staff concludes that the exclusion of cable tie wraps and uninsulated grounding conductors from the component groups subject to an AMR is acceptable. The staff's concerns in RAIs 2.5-2 and 2.5-2a are resolved.

In RAI 2.5-1, dated April 14, 2011, the staff requested that the applicant provide justification for why LRA Section 2.5 does not include elements such as resistance temperature detectors, sensors, thermocouples, and transducers in the list of components or commodity groups subject to an AMR if a pressure boundary is applicable. In its response dated May 5, 2011, the applicant stated that instrumentation with a designation of thermowell and with an intended function of pressure boundary is within the scope of license renewal and subject to an AMR. The applicant stated that these components are included in the mechanical AMR and can be found in LRA Sections 2.3.3 and 2.3.4. Based on its review, the staff confirmed that resistance temperature detectors, sensors, thermocouples, and transducers with an intended function of pressure boundary are included in the AMR lists in LRA Sections 2.3.3 and 2.3.4. Therefore, the staff finds the applicant's response to RAI 2.5-1 acceptable. Therefore, the staff's concern described in RAI 2.5-1 is resolved.

2.5.1.3 Conclusion

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

2.6 Conclusion for Scoping and Screening

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

On the basis of its review, the staff concludes that the applicant 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 South Texas Project, Units 1 and 2 (STP), by the staff of the U.S. Nuclear Regulatory Commission (NRC or the staff).

In Appendix B of its license renewal application (LRA), STP Nuclear Operating Company, (STPNOC) (the applicant) described the 40 AMPs it relies on to manage or monitor the aging of passive, long-lived structures and components (SCs). By letter dated November 30, 2011, a 41st AMP was added to monitor and maintain protective coatings.

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

NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," (the GALL Report) contains the staff's generic evaluation of existing plant programs. The GALL Report documents the technical basis for determining where existing programs are adequate without modification and where existing programs should be augmented for the period of extended operation. The evaluation results documented in the GALL Report indicate that many of the existing programs are adequate to manage the aging effects for particular SCs for license renewal without change. The GALL Report also contains recommendations concerning specific areas for which existing programs should be augmented for license renewal. An applicant may reference the GALL Report in its LRA to demonstrate that the programs at its facility correspond to those reviewed and approved in the GALL Report.

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

The GALL Report identifies the following:

- Structures, systems, and components (SSCs)
- SC materials
- environments to which the SCs are exposed
- the aging effects associated with the materials and environments
- the AMPs credited with managing or monitoring the aging effects
- recommendations for further applicant evaluations of aging management for certain component types

In preparing its LRA, the applicant credited the GALL Report, Revision 1, dated September 2005. During the applicant's preparation of its LRA, the staff was in the process of developing and implementing Revision 2 to the SRP-LR and to the GALL Report. The revisions to these two documents were issued in December 2010. The applicant's LRA was received by letter dated October 25, 2010; therefore, it was not developed to Revision 2 of either the SRP-LR or the GALL Report. This SER is administratively formatted to align with the LRA; therefore, the SRP-LR and the GALL Report numbering of inputs (e.g., AMR items) use the numbering sequence of Revision 1 for these two documents. However, the staff performed its review in accordance with the requirements of Title 10, Part 54 of the *Code of Federal Regulations* (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants"; the guidance provided in the SRP-LR, Revision 2, dated December 2010; and the guidance provided in the GALL Report, Revision 2, dated December 2010. The staff issued requests for additional information (RAIs) where LRA details differed from changes that were incorporated into Revision 2 of the SRP-LR and the GALL Report. These RAIs and the staff's evaluations of the applicant's RAI responses are documented in applicable portions further down in this section.

In addition to its review of the LRA, the staff conducted an onsite audit of selected AMRs and associated AMPs during the weeks of June 13, 2011, and June 20, 2011, as described in the "Aging Management Programs Audit Report Regarding the South Texas Project, Units 1 and 2, License Renewal Application," dated September 22, 2011. The onsite audits and reviews are designed to maximize the efficiency of the staff's LRA review, because (1) the applicant can respond to questions, (2) the staff can readily evaluate the applicant's responses, (3) the need for formal correspondence between the staff and the applicant is reduced, and (4) the result is an improvement in review efficiency.

3.0.1 Format of the License Renewal Application

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

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

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

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

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

3.0.1.1 Overview of Table 1s

Each Table 1 summarizes and compares how the facility aligns with the corresponding tables in the GALL Report. These tables are essentially the same as Tables 1 through 6 in the GALL Report, except that the "ID" column has been replaced by an "Item Number" column, the "Type" and "Unique Item" columns are removed, and the "Related Generic Item" column was replaced by the "Discussion" column. In the "Discussion" column, the applicant provided clarifying and amplifying information.

The following are examples of information that the applicant placed within this column:

- further evaluation recommended—information or reference to information on further evaluations
- name of a plant-specific program
- exceptions to GALL Report assumptions
- discussion of how the item 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 each Table 1 allows the staff to align a specific row in the table with the corresponding GALL Report table row so that the consistency can be checked easily.

3.0.1.2 Overview of Table 2s

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

- Component type—The first column lists LRA Section 2 component types subject to an AMR in alphabetical order.
- Intended function—The second column identifies the license renewal intended functions, including abbreviations, where applicable, for the listed component types. Definitions and abbreviations of intended functions are in LRA Table 2.1-1.
- Material—The third column lists the particular construction material(s) for the component type.
- Environment—The fourth column lists the environments to which the component types are exposed. Internal and external service environments are indicated with a list of these environments in LRA Tables 3.0-1, 3.0-2, and 3.0-3.
- Aging effect requiring management (AERM)—The fifth column lists AERMs. As part of the AMR process, the applicant determined any AERMs for each combination of material and environment.
- AMP—The sixth column lists the AMPs that the applicant uses to manage the identified aging effects.

- NUREG-1801 Volume 2 Item—The seventh column lists the GALL Report item(s) identified in the LRA as similar to the AMR results. The applicant compared each combination of component type, material, environment, AERM, and AMP in LRA Table 2 with the GALL Report items. If there were no corresponding items in the GALL Report, the applicant marked the column entry as "none" to identify that no AMR results in the GALL Report tables correspond to the item in the LRA tables.
- Table 1 Item—The eighth column lists the corresponding summary item number from LRA Table 1. For each LRA Table 2 AMR item, if the applicant identified results consistent with the GALL Report, the corresponding Table 1 item summary number is listed in this column in LRA Table 2. If there is no corresponding item in the GALL Report, the entry in column eight is left blank. In this manner, the reader can correlate information from the two tables.
- Notes—The ninth column lists the corresponding notes used to identify how the information in each Table 2 aligns with the information in the GALL Report. The notes identified by letters were developed by an NEI work group and will be used in future LRAs. Any required plant-specific notes are identified by numbers and provide additional information about the consistency of the item with the GALL Report.

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

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 to be 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.

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 functions consistent with the plant's current licensing basis (CLB) for the period of extended operation, as required by 10 CFR Part 54.

3.0.2.1 Review of AMPs

For AMPs for which the applicant claimed consistency with the GALL Report AMPs, the staff conducted either an audit or a technical review to confirm whether the applicant's AMPs are consistent with the GALL Report. 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 its adequacy. The staff evaluated the AMPs against the following 10 program elements defined in SRP-LR Appendix A:

(1) Scope of the Program—Scope of the program should include the specific SCs subject to an AMR for license renewal.

(2) Preventive Actions—Preventive actions should prevent or mitigate aging degradation.

(3) Parameters Monitored or Inspected—Parameters monitored or inspected should be linked to the degradation of the particular structure or component intended functions.

(4) Detection of Aging Effects—Detection of aging effects should occur before there is a loss of structure or component intended functions. This includes aspects such as method or technique (i.e., visual, volumetric, surface inspection), frequency, sample size, data collection, and timing of new and one-time inspections to ensure timely detection of aging effects.

(5) Monitoring and Trending—Monitoring and trending should provide predictability of the extent of degradation, as well as timely corrective or mitigating actions.

(6) Acceptance Criteria—Acceptance criteria, against which the need for corrective action will be evaluated, should ensure that the structure or component intended functions are maintained under all CLB design conditions during the period of extended operation.

(7) Corrective Actions—Corrective actions, including root cause determination and prevention of recurrence, should be timely.

(8) Confirmation Process—The confirmation process should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.

(9) Administrative Controls—Administrative controls should provide for a formal review and approval process.

(10) Operating Experience—Operating experience of the AMP, including past corrective actions resulting in program enhancements or additional programs, should provide objective evidence to support the conclusion that the effects of aging will be adequately managed so that the SC-intended functions will be maintained during the period of extended operation.

Details of the staff's audit evaluation of program elements (1) through (6) and portions of (10) are documented in the AMP audit report and summarized in SER Section 3.0.3.

LRA Section B1.4 describes the applicant's methods for considering operating experience for its AMPs. SER Section 3.0.5 contains the staff's evaluation of the remaining portions of program element (10) and the applicant's use of operating experience, primarily concerning future operating experience; this aspect is applicable to both existing and new AMPs.

The staff reviewed the applicant's Quality Assurance (QA) Program and documented its evaluation in SER Section 3.0.4. The staff's evaluation of the QA Program included assessments of program elements (7), (8), and (9).

3.0.2.2 Review of AMR Results

Each LRA Table 2 contains information concerning whether the AMRs identified by the applicant align with the GALL Report AMRs. For a given AMR in a Table 2, the staff reviewed the intended function, material, environment, AERM, and AMP combination for a particular system component type. Item numbers in column 7 of the LRA, "NUREG-1801 Volume 2 Item," correlate to an AMR combination as identified in the GALL Report. The staff also conducted onsite audits to confirm these correlations. A blank in column 7 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. Column 8, "Table 1 Item," provides a reference number that indicates the corresponding row in Table 1.

3.0.2.2.1 Applicant Definition Related to Internal and External Air Service Environments

The applicant defined its internal and external service environments in LRA Tables 3.0-1 and 3.0-2. LRA Table 3.0-1 states that the applicant's environment of "plant indoor air" encompasses the GALL Report defined environments (e.g., "air-indoor controlled," "air-indoor uncontrolled," "condensation," "air, moist," "air with steam or water leakage"), depending on whether "plant indoor air" is an internal or external environment. The GALL Report identifies that several materials experience different aging effects when exposed to air that contains moisture or condensation as opposed to when they are exposed to air that is usually dry. Because the applicant used the term "plant indoor air" in its LRA Table 2s, rather than the GALL Report defined environments, the staff could not determine whether the proper aging effects and AMPs had been identified for those AMR items exposed to the environment of "plant indoor air." By letter dated September 22, 2011, the staff issued RAI 3.0-1 requesting that the applicant identify which AMR items in the LRA are exposed to a "plant indoor air" environment for which humidity, condensation, moisture, or other contaminants are present. If, in identifying these items, it is determined that the AMR items have additional AERMs, the staff asked the applicant to propose an AMP to manage the aging effect or state the basis for why no AMP is required.

In its response dated November 21, 2011, the applicant stated that that some AMR items were inadvertently associated with a GALL Report item for exposure to "air-indoor controlled" that should have been associated with a GALL Report item for exposure to "air-indoor uncontrolled." The applicant made the associated changes to LRA Tables 3.3.2-4, 3.3.2-17, 3.3.2-19, 3.3.2-20, and 3.3.2-21 for aluminum components and LRA Table 3.3.2-27 for carbon steel components. These LRA changes did not affect the aging effects for the aluminum AMR items but resulted in the addition of loss of material as an applicable aging affect for the carbon steel components, which the applicant will manage using the External Surfaces Monitoring Program.

However, in its response, the applicant did not revise its definition of "plant indoor air" or make any other changes to the LRA to indicate whether the remaining AMR items that have an environment of "plant indoor air" are exposed to moisture or condensation. In a teleconference held December 12, 2011, the applicant clarified that no changes were made to the definition of "plant indoor air" because whenever the term is used in the LRA, there is a potential for moisture in the air. Considering that the "plant indoor air" environment always has the potential to contain moisture, the staff identified several instances in which the applicant inappropriately concluded that aluminum, steel, galvanized steel, stainless steel, copper alloy, and nickel alloy components exposed to a "plant indoor air" environment have no AERMs. By letter dated February 8, 2012, the staff submitted followup RAI 3.0-1a requesting that the applicant explain—for all of the aluminum, steel, galvanized steel, stainless steel, copper alloy, and nickel alloy AMR items in the LRA with an environment of "plant indoor air" that do not have any aging effects identified—why the components have no AERMs or identify appropriate aging effects and AMPs consistent with the guidance in the GALL Report, Revision 2, for air environments that contain moisture.

In a teleconference held January 18, 2012, to discuss the draft RAI, the applicant stated that, for internal surfaces exposed to "plant indoor air," the air is assumed to contain moisture, and the AMR items will be revised to reference an SRP-LR item for exposure to condensation or moist air. The applicant also stated that, for external surfaces exposed to "plant indoor air," only systems that operate below the dew point of the air, such as cooling coils, are subject to moisture, and those AMR items will be revised to reference the appropriate SRP-LR items for exposure to moisture.

By letter dated February 27, 2012, the applicant revised its definitions of "plant indoor air" as discussed in the conference call to clarify that: (a) internal surfaces of components exposed to "plant indoor air" are assumed to experience condensation; (b) external surfaces of components exposed to "plant indoor air" are normally dry, except for components in chilled water and heating, ventilation, and air conditioning (HVAC) systems; and (c) external surfaces of components exposed to "plant indoor air" in chilled water and HVAC systems may experience condensation. The applicant revised all of the AMR items for components with internal surfaces exposed to "plant indoor air" to credit the Inspection of Internal Surfaces in Miscellaneous Components and Ducting Program to manage loss of material. The applicant revised the AMR items for components in chilled water and HVAC systems with external surfaces exposed to "plant indoor air" to credit the External Surfaces Monitoring Program to manage loss of material.

The staff finds the applicant's response acceptable because the applicant evaluated which components exposed to a "plant indoor air" environment are exposed to air that contains moisture and has revised the LRA to manage loss of material for all of the components potentially exposed to moisture, which is consistent with the GALL Report recommendations. The staff's individual AMR item evaluations for components exposed to "plant indoor air" are documented in the appropriate SER sections for their associated Table 1 references. The staff's concerns described in RAIs 3.0-1 and 3.0-1a are resolved.

3.0.2.3 UFSAR Supplement

Consistent with the SRP-LR for the AMRs and associated AMPs that it reviewed, the staff also reviewed the updated final safety analysis report (UFSAR) supplement that summarizes the applicant's programs and activities for managing the effects of aging for the period of extended operation to determine if it provides an adequate description of the program or activity, as required by 10 CFR 54.21(d). SER Section 3.0.5.3 contains more details on the staff's process for evaluating the applicant's UFSAR supplements.

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 confirm that the applicant's activities and programs will adequately manage the effects of aging on SCs. The staff also conducted detailed discussions and interviews with the applicant's license renewal project personnel and others with technical expertise relevant to aging management.

3.0.3 Aging Management Programs

Table 3.0-1 presents the AMPs credited by the applicant and described in LRA Appendix B. The table also indicates if the AMP is an existing or new program, the GALL Report AMP with which the applicant asserted consistency, and the SER section in which the staff's evaluation of the program is documented.

Table 3.0-1 STP Aging Management Programs

Applicant AMP	LRA Sections	New or Existing Program	Applicant Comparison to the GALL Report	GALL Report AMP	SER Section
ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	B2.1.1, A1.1	Existing	Consistent with the GALL Report	XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	3.0.3.1.1
Water Chemistry	B2.1.2, A1.2	Existing	Consistent with the GALL Report, with Enhancement	XI.M2, "Water Chemistry"	3.0.3.2.1
Reactor Head Closure Studs	B2.1.3, A1.3	Existing	Consistent with the GALL Report, with Exceptions and Enhancements	XI.M3, "Reactor Head Closure Studs"	3.0.3.2.2
Boric Acid Corrosion	B2.1.4, A1.4	Existing	Consistent with the GALL Report, with Enhancement	XI.M10, "Boric Acid Corrosion"	3.0.3.2.3
Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of PWRs	B2.1.5, A1.5	Existing	Consistent with the GALL Report	XI.M11A, "Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors"	3.0.3.1.2
Flow-Accelerated Corrosion	B2.1.6, A1.6	Existing	Consistent with the GALL Report, with Exceptions	XI.M17, "Flow-Accelerated Corrosion"	3.0.3.2.4
Bolting Integrity	B2.1.7, A1.7	Existing	Consistent with the GALL Report, with Exceptions and Enhancements	XI.M18, "Bolting Integrity"	3.0.3.2.5
Steam Generator Tube Integrity	B2.1.8, A1.8	Existing	Consistent with the GALL Report, with Enhancement	XI.M19, "Steam Generator Tube Integrity"	3.0.3.1.3
Open-Cycle Cooling Water System	B2.1.9, A1.9	Existing	Consistent with the GALL Report, with Exception and Enhancements	XI.M20, "Open-Cycle Cooling Water System"	3.0.3.2.6

Applicant AMP	LRA Sections	New or Existing Program	Applicant Comparison to the GALL Report	GALL Report AMP	SER Section
Closed-Cycle Cooling Water System	B2.1.10, A1.10	Existing	Consistent with the GALL Report, with Exceptions and Enhancements	XI.M21, “Closed-Cycle Cooling Water System”	3.0.3.2.7
Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	B2.1.11, A1.11	Existing	Consistent with the GALL Report, with Enhancement	XI.M23, “Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems”	3.0.3.2.8
Fire Protection	B2.1.12, A1.12	Existing	Consistent with the GALL Report, with Exception and Enhancements	XI.M26, “Fire Protection”	3.0.3.2.9
Fire Water System	B2.1.13, A1.13	Existing	Consistent with the GALL Report, with Exceptions and Enhancements	XI.M27, “Fire Water System”	3.0.3.2.10
Fuel Oil Chemistry	B2.1.14, A1.14	Existing	Consistent with the GALL Report, with Exceptions and Enhancements	XI.M30, “Fuel Oil Chemistry”	3.0.3.2.11
Reactor Vessel Surveillance	B2.1.15, A1.15	Existing	Consistent with the GALL Report, with Enhancements	XI.M31, “Reactor Vessel Surveillance”	3.0.3.2.12
One-Time Inspection	B2.1.16, A1.16	New	Consistent with the GALL Report	XI.M32, “One-Time Inspection”	3.0.3.1.4
Selective Leaching of Materials	B2.1.17, A1.17	New	Consistent with the GALL Report, with Exceptions	XI.M33, “Selective Leaching of Materials”	3.0.3.2.13
Buried Piping and Tanks Inspection	B2.1.18, A1.18	Existing	Consistent with the GALL Report, with Exceptions and Enhancements	XI.M41, “Buried and Underground Piping and Tanks”	3.0.3.2.14
One-Time Inspection of ASME Code Class 1 Small-Bore Piping	B2.1.19, A1.19	New	Consistent with the GALL Report, with Exception	XI.M35, “One-Time Inspection of ASME Code Class 1 Small-Bore Piping”	3.0.3.2.15
External Surfaces Monitoring Program	B2.1.20, A1.20	New	Consistent with the GALL Report, with Exceptions and Enhancement	XI.M36, “External Surfaces Monitoring of Mechanical Components”	3.0.3.2.16
Flux Thimble Tube Inspection	B2.1.21, A1.21	Existing	Consistent with the GALL Report, with Enhancement	XI.M37, “Flux Thimble Tube Inspection”	3.0.3.2.17

Applicant AMP	LRA Sections	New or Existing Program	Applicant Comparison to the GALL Report	GALL Report AMP	SER Section
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	B2.1.22, A1.22	New	Consistent with the GALL Report, with Exception	XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	3.0.3.2.18
Lubricating Oil Analysis	B2.1.23, A1.23	Existing	Consistent with the GALL Report, with Exception and Enhancements	XI.M39, “Lubricating Oil Analysis”	3.0.3.2.19
Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.24, A1.24	New	Consistent with the GALL Report	XI.E1, “Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements”	3.0.3.1.5
Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.25, A1.25	Existing	Consistent with the GALL Report, with Enhancements	XI.E3, “Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements”	3.0.3.2.20
Metal Enclosed Bus	B2.1.26, A1.26	Existing	Consistent with the GALL Report, with Enhancement	XI.E4, “Metal Enclosed Bus”	3.0.3.2.21
Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.36, A1.36	New	Consistent with the GALL Report	XI.E6, “Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements”	3.0.3.1.6
ASME Code Section XI, Subsection IWE	B2.1.27, A1.27	Existing	Consistent with the GALL Report, with Exceptions and Enhancement	XI.S1, “ASME Section XI, Subsection IWE”	3.0.3.2.22
ASME Code Section XI, Subsection IWL	B2.1.28, A1.28	Existing	Consistent with the GALL Report, with Enhancement	XI.S2, “ASME Section XI, Subsection IWL”	3.0.3.2.23
ASME Code Section XI, Subsection IWF	B2.1.29, A1.29	Existing	Consistent with the GALL Report, with Enhancement	XI.S3, “ASME Section XI, Subsection IWF”	3.0.3.2.24
10 CFR Part 50, Appendix J	B2.1.30, A1.30	Existing	Consistent with the GALL Report, with Exceptions and Enhancement	XI.S4, “10 CFR Part 50, Appendix J”	3.0.3.2.25
Masonry Wall Program	B2.1.31, A1.31	Existing	Consistent with the GALL Report, with Enhancement	XI.S5, “Masonry Walls”	3.0.3.2.29

Applicant AMP	LRA Sections	New or Existing Program	Applicant Comparison to the GALL Report	GALL Report AMP	SER Section
Structures Monitoring Program	B2.1.32, A1.32	Existing	Consistent with the GALL Report, with Enhancements	XI.S6, “Structures Monitoring”	3.0.3.2.26
RG 1.127 Inspection of Water-Control Structures with Nuclear Power Plants	B2.1.33, A1.33	Existing	Consistent with the GALL Report, with Exception and Enhancements	XI.S7, “RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants”	3.0.3.2.27
Protective Coating Monitoring and Maintenance Program	B2.1.39, A1.39	Existing	Plant-Specific	NA—Plant-Specific	3.0.3.3.4
Metal Fatigue of Reactor Coolant Pressure Boundary	B3.1, A2.1	Existing	Consistent with the GALL Report, with Enhancements	X.M1, “Metal Fatigue of Reactor Coolant Pressure Boundary”	3.0.3.2.28
Environmental Qualification (EQ) of Electrical Components	B3.2, A2.2	Existing	Consistent with the GALL Report	X.E1, “Environmental Qualification (EQ) of Electrical Components”	3.0.3.1.7
Concrete Containment Tendon Prestress	B3.3, A2.3	Existing	Consistent with the GALL Report	X.S1, “Concrete Containment Tendon Prestress”	3.0.3.1.8
Nickel-Alloy Aging Management Program	B2.1.34, A1.34	Existing	Plant-Specific	NA—Plant-Specific	3.0.3.3.1
PWR Reactor Internals	B2.1.35, A1.35	New	Plant-Specific	NA—Plant-Specific	3.0.3.3.2
Selective Leaching of Aluminum Bronze	B2.1.37, A1.37	Existing	Plant-Specific	NA—Plant-Specific	3.0.3.3.3

3.0.3.1 AMPs That Are Consistent with the GALL Report

In LRA Appendix B, the applicant identified the following AMPs as being consistent with the GALL Report:

- American Society of Mechanical Engineers (ASME) Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
- Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors
- Steam Generator Tube Integrity
- One-Time Inspection
- Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
- Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

- Environmental Qualification (EQ) of Electrical Components
- Concrete Containment Tendon Prestress

3.0.3.1.1 ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

Summary of Technical Information in the Application. LRA Section B2.1.1 describes the existing ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program as consistent with GALL Report AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD." The applicant stated that this program manages cracking, loss of fracture toughness, and loss of material in Class 1, 2, or 3 piping and components within the scope of license renewal. The applicant also stated that this program includes periodic visual, surface, volumetric examinations, and leakage tests of Class 1, 2, or 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting. The applicant further stated that this program is updated during each successive 120-month (10-year) inspection interval to comply with the requirements of the ASME Code Section XI, Subsections IWB, IWC, and IWD, edition and addenda in accordance with 10 CFR 50.55a, subject to prior approval of the edition and addenda by the NRC.

Staff Evaluation. During its audit, the staff reviewed the applicant's assertion 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.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.

The "detection of aging effects" program element in GALL Report AMP XI.M1 states that ASME Code Section XI Table IWB-2500-1 is used to determine the examination of Categories B-F and B-J welds. The staff noted that the applicant is using relief requests approved by the NRC for the current 10-year interval, which includes an alternative to use a risk-informed methodology, Category R-A, in lieu of the ASME Code Section XI, Categories B-F and B-J. Although LRA Section B2.1.1 did not indicate whether a risk-informed methodology will be used during the period of extended operation, the applicant stated in the Program Description that it will comply with 10 CFR 50.55a during the extended period of operation as required by the plant's operating license, including requirements for implementing ASME Code Section XI, Subsections IWB, IWC, and IWD inspections. Therefore, the program requirements for Categories B-F and B-J in LRA Section B2.1.1 are consistent with GALL Report AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and are acceptable.

Based on its audit, the staff finds that elements one through six of the applicant's ASME Code Section XI Inservice Inspection, Subsections 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 B2.1.1 summarizes operating experience related to the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The applicant indicated that this program is based on the ASME Code Section XI, Subsections IWB, IWC, and IWD, which is based on industry-wide operating experience, research data, and technical evaluations. The applicant indicated that plant-specific examples are documented in its inservice inspection summary reports as well as in the Corrective Action Program (CAP) records. The staff sampled inspection results from the current 10-year interval inservice inspection summary reports. For example, indications were found in a body-to-bonnet seal weld in a valve in the RHR system of Unit 1. The indications were evaluated in accordance with acceptance criteria of the ASME Code Section XI, Subsections IWB, IWC, and IWD requirements, and the seal weld was repaired accordingly. In another case, a steam leak was detected on an inlet weld for Unit 2 vent valve RC-0127. The applicant performed a root cause analysis to identify causal factors, performed repair to the weld, performed extent of condition on similar welds, and implemented measures for monitoring and correction of causal factors prior to restart. The staff reviewed the applicant's inservice inspection summary reports submitted for the current and previous 10-year inservice inspection intervals for both units to confirm that the applicant's implementation of the program was effective in detecting, trending, and correcting those aging effects for which the program was credited. The staff's review of these inservice inspection summary reports did not reveal any evidence that would demonstrate that the program was ineffective in detecting the aging effects managed by this program.

The staff reviewed operating experience information, in the application and during the audit, to determine whether the applicable aging effects, 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 evaluated and incorporated 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 applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

<u>UFSAR Supplement</u>. LRA Section A1.1 provides the UFSAR supplement for the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program, as described in SRP-LR Table 3.0-1.

The staff concludes that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its audit and review of the applicant's ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant 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).

3.0.3.1.2 Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors

Summary of Technical Information in the Application. LRA Section B2.1.5 describes the existing Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors 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 Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program manages cracking due to primary water stress corrosion in nickel alloy vessel head penetration nozzles and associated welds as well as loss of material in the reactor vessel (RV) closure head. The applicant also stated that this program was developed in response to NRC Order EA-03-009 and that this order has been superseded by ASME Code Case N-729-1, "Alternative Examination Requirements for PWR [pressurized-water reactor] Reactor Vessel Upper Heads with Nozzles Having Pressure-Retaining Partial-Penetration Welds, Section XI, Division 1," subject to the conditions specified in 10 CFR 50.55 a(g)(6)(ii). The applicant further stated that its program is consistent with the Code Case and conditions and, thereby, with the regulatory requirements concerning these components.

Staff Evaluation. The staff reviewed the applicant's claim of consistency with the GALL Report by considering Revisions 1 and 2 of the GALL Report along with Commission Order EA-03-009, ASME Code Cases, and applicable NRC regulations as described below. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The applicant filed its LRA in accordance with GALL Report, Revision 1 (AMP XI.M11A). AMP XI.M11A manages the aging of applicable components based on Commission Order EA-03-009 as revised. The staff notes that, once a license implements the requirements of ASME Code Case N-729-1, NRC Order EA-03-009 no longer applies to that licensee and shall be deemed withdrawn, as specified in 10 CFR 50.55a(g)(6)(ii)(D).

Subsequent to the submission of the LRA, the staff issued the GALL Report, Revision 2. In the GALL Report, Revision 2, AMPs XI.M11 and XI.M11A are combined in AMP XI.M11B, "Cracking of Nickel-Alloy Components and Loss of Material due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (PWRs Only)." This AMP ensures the adequacy of aging management for upper head penetrations by recommending the use of ASME Code Case N-729-1. Based on the GALL Report, Revision 2, consistency with Code Case N-729-1 is deemed to be consistent with program elements one through six of the AMP as the AMP recommends no actions beyond those contained in the Code Case.

Prior to the issuance of the GALL Report, Revision 2, the staff revised 10 CFR 50.55.a. Paragraph (g)(6)(ii)(D) of 10 CFR 50.55a mandates the use of Code Case N-729-1 subject to the conditions specified in paragraphs (g)(6)(ii)(D)(2) through (6).

Based on the information above, the staff notes that the applicant included the use of Code Case N-729-1 in its LRA; that, in accordance with GALL Report, Revision 2 AMP XI.M11B, the use of Code Case N-729-1 provides an acceptable method of aging management; and that, 10 CFR 50.55a(g)(6)(ii)(D) mandates the use of Code Case N-729-1 and precludes any variation between the LRA AMP and the GALL Report AMP. As a result of the inability of the applicant to deviate from an acceptable approach to the management of aging of upper head penetrations, a detailed audit of each of program elements one through six of the LRA AMP is unnecessary. The staff, therefore, finds elements one through six of the applicant's AMP acceptable.

Operating Experience. LRA Section B2.1.5 summarizes operating experience related to the Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program. In its review of the applicant's operating experience, the staff noted that the head for Unit 1 was replaced during refueling outage (RFO) 1RE15 (October 2009), and the head for Unit 2 was replaced during RFO 2RE14 (April 2010). The staff also noted that the components penetrating the new heads were fabricated and welded using primary water stress corrosion cracking (PWSCC) resistant materials. Due to the recent nature of these head replacements, no pertinent operating experience is expected at this time. Additionally, the staff is not aware of any industry operating experience that is not bounded by Code Case N-729-1. The staff further notes that the LRA indicates that operating experience will be incorporated into the program as it becomes available. The staff finally notes that 10 CFR 50.55a(g)(6)(ii)(D)(6) mandates the incorporation of operating experience in the use of Code Case N-729-1 in that, if flaws are discovered, the inspection interval permitted by the Code Case is reduced. Based on the available operating experience, the staff finds that the aging management approach (i.e., Code Case N-729-1), proposed by the applicant, recommended by the GALL Report AMP, and required by 10 CFR 50.55a(g)(6)(ii)(D), will be effective in managing the aging of the applicable components.

Based on its audit and review of the application, the staff finds that the applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A1.5 provides the UFSAR supplement for the Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program. The staff reviewed the description of the LRA AMP provided in the UFSAR supplement. The staff found this description varied considerably from that included in the SRP-LR, Revision 1. However, given the changes to the program, which are recommended in the GALL Report, Revision 2, and required by 10 CFR 50.55a, the program description provided in the UFSAR supplement constitutes an adequate description of the program.

Conclusion. On the basis of its review of the applicant's Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program, the staff concludes that while the program varies from that described in the GALL Report, Revision 1, the AMP complies with 10 CFR 50.55a and that the GALL Report, Revision 2, does not recommend any aging management issues beyond that required by regulation. Based on compliance with 10 CFR 50.55a, 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).

3.0.3.1.3 Steam Generator Tube Integrity

Summary of Technical Information in the Application. LRA Section B2.1.8, as amended by a letter dated January 5, 2017, describes the existing Steam Generator Tube Integrity Program as consistent, with an enhancement, with the GALL Report AMP XI.M19, "Steam Generator Tube Integrity." The applicant stated that the Steam Generator Tube Integrity Program manages the loss of material of steam generator (SG) tubes, tube support plates, secondary side access covers, secondary nozzles, moisture separators, internal structures, flow distribution baffles, feedwater rings, auxiliary feedwater (AFW) spray pipes, and primary head and divider plates. The applicant also indicated that the program manages the cracking of SG tubes, plugs, tube support plates, secondary side access covers, secondary nozzles, primary head and divider plates, internal structures, flow distribution baffles, feedwater rings, and AFW spray pipes. The program further manages the wall thinning of moisture separators, feedwater rings, and AFW spray pipes.

In addition, the applicant stated that the program ensures the integrity of the primary to secondary pressure boundary through assessments of potential degradation mechanisms, inspections, tube integrity assessment, maintenance plugging and repairs, primary to secondary leakage monitoring, maintenance of secondary-side integrity, primary side and secondary side water chemistry, and foreign material exclusion. The applicant further stated that training and qualification standards for personnel engaged in the acquisition or evaluation of SG nondestructive examination activities are specified in a station administrative procedure, and inspection practices are consistent with the Electric Power Research Institute (EPRI) PWR Steam Generator Examination Guidelines.

In a conference call held on March 8, 2012, the applicant clarified that the secondary side access covers and secondary nozzles are included in the AMP because they are components internal to the SGs. Including these components in the applicant's program is consistent with GALL Report AMP XI.M19. The applicant also stated that, as listed in LRA Table 3.1.2-4, external components typically associated with the SG shell—such as the secondary nozzles and safe ends, the secondary access covers, and SG secondary shell, which are made of carbon steel—are included in the applicant's ASME Code Section XI, Inservice Inspection, Subsection IWB, IWC, and IWD Program and other programs for managing their respective aging effects, consistent with the GALL Report recommendations. The staff reviewed this response and finds it acceptable because the program described in GALL Report AMP XI.M19 is applicable to secondary side components that are contained within the SG.

In its letter dated January 5, 2017 (i.e., response to RAI B2.1.8-3), the applicant identified a program enhancement to be consistent with License Renewal Interim Staff Guidance (LR-ISG) 2016-01, "Changes to Aging Management Guidance for Various Steam Generator Components," in the *Federal Register* on December 7, 2016. The program enhancement will implement periodic visual inspections on SG channel head internal areas (including divider plates) and tubesheet primary side. These inspections will be used to manage loss of material due to boric acid corrosion for channel heads and tubesheets and cracking due to PWSCC for divider plates and tube-to-tubesheet welds.

<u>Staff Evaluation</u>. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.M19.

For the "detection of aging effects" program element, the staff determined there was a need for additional information, which resulted in the issuance of RAIs, as discussed below.

The "detection of aging effects" program element in GALL Report AMP XI.M19 recommends the Water Chemistry AMP to manage potential cracking due to PWSCC in SG nickel alloy tube-to-tubesheet welds exposed to reactor coolant. However, during its audit, the staff found that the applicant's Steam Generator Tube Integrity Program did not provide information on the tubesheet clad material or the tube-to-tubesheet weld region. By letter dated November 3, 2011, the staff issued RAI B2.1.8-1 requesting that the applicant confirm that the tube-to-tubesheet weld is part of the reactor coolant pressure boundary (RCPB) and clarify the materials used in forming the tube-to-tubesheet joins (welds). If the tube-to-tubesheet weld and cladding material have chemical compositions similar to Alloy 600, the staff asked the applicant to provide an AMP to manage the potential aging effect of cracking due to PWSCC.

In its response dated December 6, 2011, the applicant stated that the tube-to-tubesheet weld is part of the RCPB for the STP Model Delta 94 SGs. The applicant stated that the Model Delta 94 replacement SG tubesheets are made of carbon steel clad with Alloy 690. It stated further that the tube-to-tubesheet welds are flush-fusion welds with Alloy 690 cladding. The material does not have a chemical composition similar to Alloy 600 (Alloy 82 or Alloy 182). The applicant also stated that the Steam Generator Tube Integrity and Water Chemistry programs are credited for managing PWSCC associated with the carbon steel clad with Alloy 690.

The staff finds the applicant's response acceptable because the Water Chemistry Program is capable of managing potential cracking due to PWSCC in the SG tube-to-tubesheet welds composed of Alloy 690-type material exposed to reactor coolant. The GALL Report recommends the Water Chemistry Program to manage this aging effect. In addition, the staff notes that the tube-to-tubesheet weld and cladding material consist of Alloy 690, which is more resistant to PWSCC than Alloy 600. The staff's concern described in RAI B2.1.8-1 is resolved.

As documented in the summary of technical information in this SER section, the applicant's January 5, 2017, letter identifies a program enhancement to be consistent with the guidance in LR-ISG-2016-01. The staff's evaluation of the program enhancement is further described below following the staff's evaluation regarding LR-ISG-2011-02, "Aging Management Program for Steam Generators," published in the *Federal Register* on December 1, 2011. The January 5, 2017, letter also indicates that the Water Chemistry Program and Steam Generator Tube Integrity Program with enhancement are used to manage cracking due to PWSCC for the SG tube-to-tubesheet welds, consistent with LR-ISG-2016-01. The staff's evaluation of the applicant's aging management for this aging effect is documented in SER Section 3.1.2.2.16, item 1.

The staff also noted during the audit that the applicant reported that its SG divider plates and associated weld material are made of Alloy 690 or its equivalent. The staff's evaluation of the applicant's aging management for cracking of these components is documented in SER Section 3.1.2.1.8.

During its review, the staff noted that LR-ISG-2011-02, "Aging Management Program for Steam Generators," indicates that Revision 3 of NEI 97-06, "Steam Generator Program Guidelines," updates Revision 2 of the NEI guidance and is suitable to manage the aging effects of SGs. LR-ISG-2011-02 also provides a correct reference to EPRI SG integrity assessment guidelines (i.e., EPRI Report 1019038, "Steam Generator Integrity Assessment Guidelines," Revision 3, November 2009). The staff further noted that the LRA and the applicant's annual updates of the LRA (dated October 28, 2013; October 22, 2014; and October 22, 2015) do not clearly indicate whether the applicant's program is consistent with the guidance in LR-ISG-2011-02.

On February 29, 2016, the staff issued RAI B2.1.8-2 requesting that the applicant clarify whether its program is consistent with the guidance in LR-ISG-2011-02. In its response dated

March 10, 2016, the applicant confirmed that the program includes the guidance provided in NEI 97-06, Revision 3 and EPRI Report 1019038, as described in LR-ISG-2011-02. The staff finds the applicant's response acceptable because the applicant confirmed the consistency of the program with the guidance in LR-ISG-2011-02. The staff's concern described in RAI B2.1.8-2 is resolved.

In addition, the staff issued LR-ISG-2016-01 (ADAMS Accession No. ML16237A383), which provides the following guidance on aging management for steam generator components:

- visual inspections on SG head internal areas (head interior surfaces, divider plate assemblies, tubesheets (primary side) and tube-to-tubesheet welds) in order to identify signs of cracking or loss of material (e.g., rust stains and distortion of divider plates)

- frequency of the visual inspections: at least every 72 effective full power months or every third refueling outage, whichever results in more frequent inspections

- implementation of the recent EPRI SG guidelines such as (a) EPRI Report 1022832 (primary-to-secondary leak guidelines), (b) EPRI Report 1025132 (in-situ pressure test guidelines), (c) EPRI Report 3002007571 (integrity assessment guidelines), and (d) EPRI Report 3002007572 (examination guidelines)

The staff found a need for additional information to confirm whether the applicant's program is consistent with the guidance in LR-ISG-2016-01. By letter dated December 8, 2016, the staff issued RAI B2.1.8-3 requesting that the applicant clarify whether the Steam Generator Tube Integrity Program is consistent with the guidance discussed above (i.e., conduct of visual inspections, visual inspection frequency, and implementation or plans for implementation of the recent EPRI SG guidelines by the industry-provided implementation dates). If not, the applicant was requested to provide justification for why the applicant's program is adequate for aging management. In addition, the staff requested that the applicant provide an updated UFSAR supplement for this program as necessary.

In its response dated January 5, 2017, the applicant stated that LRA Table 3.1.2-4 (AMR items), Section A1.8 (UFSAR supplement), and Section B2.1.8 (program description) have been revised to be consistent with the guidance in LR-ISG-2016-01. The applicant also indicated that the program basis document has been revised accordingly. The applicant further identified a program enhancement (Commitment No. 48) that will implement visual inspections on SG head internal areas, consistent with LR-ISG-2016-01. The SG heads are also called SG channel heads or primary heads.

In addition, the applicant confirmed that the frequency of these visual inspections is consistent with the inspection frequency specified in LR-ISG-2016-01 (i.e., at least every 72 effective full power months or every third refueling outage, whichever results in more frequent inspections). The applicant also confirmed that the Steam Generator Tube Integrity Program will be used to manage loss of material and cracking for SG heads, divider plates, tubesheets and tube-to-tubesheet welds. The applicant further confirmed that the program implements the recent EPRI SG guidelines discussed in LR-ISG-2016-01 within the implementation period specified by the industry. The staff noted that a typical implementation period for EPRI SG guidelines is 14 months or less following the publication date of the guidelines.

Based on its review, the staff finds the applicant's response acceptable because the applicant confirmed: (1) the program enhancement will implement visual inspections on SG head internal areas in order to identify signs of cracking or loss of material, consistent with LR-ISG-2016-01; (2) the program implements the EPRI SG guidelines discussed in LR-ISG-2016-01 within the implementation period specified by the industry, which will ensure timely implementation of the guidelines; and (3) the use of the program, which includes the periodic visual inspections, is adequate to manage loss of material and cracking for SG head internal areas (including divider plates and tubesheets), consistent with LR-ISG-2016-01. The concern described in RAI B2.1.8-3 is resolved.

Enhancement. As discussed above, the applicant's January 5, 2017, response to RAI B2.1.8-3 identifies a program enhancement to the "scope of program," "parameters monitored or inspected," and "acceptance criteria" program elements. In this enhancement, the applicant indicated that: (1) procedures will be revised to specify visual inspections of the SG divider plate assemblies, tubesheets (primary side), tube-to-tubesheet welds, and primary head (interior surfaces) for signs of cracking and loss of material; (2) procedures will be revised to perform these visual inspections at least every 72 effective full power months or every third refueling outage, whichever results in more frequent inspections; and (3) procedures will be revised to evaluate the acceptability of any degraded conditions of these SG components on a case-by-case basis. The applicant also indicated that this enhancement will be implemented no later than 6 months prior to the period of extended operation (Commitment No. 48).

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M19 as revised in LR-ISG-2016-01. Based on its review, the staff finds it acceptable because when it is implemented the program will include periodic visual inspections on SG channel head internal areas, which are adequate to detect and manage cracking and loss of material, consistent with LR-ISG-2016.

Based on its audit and review of the applicant's Steam Generator Tube Integrity Program, and review of the applicant's responses to RAI B2.1.8-1, B2.1.8-2, and B2.1.8-3, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M19 as revised in LR-SG-2016-01. In addition, the staff reviewed the enhancement associated with the corresponding program elements in GALL Report AMP XI.M19 and found it acceptable because, when implemented, it will align the corresponding program elements with that of the GALL Report AMP XI.M19 and make this AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.8 summarizes operating experience related to the Steam Generator Tube Integrity Program.

The applicant stated that the degradation assessment for STP examines industry experience for Westinghouse advanced-design SGs to determine the potential degradation mechanisms for STP SGs. The applicant also stated that the dominant degradation mechanisms detected in U.S. replacement SGs equipped with Alloy 690 tubing have been foreign object and anti-vibration bar (AVB) wear.

It was reported that tube wear at AVB intersections and loose parts wear are considered potential degradation mechanisms. The applicant also stated that other degradation mechanisms have a very low likelihood of occurrence. The applicant stated that "STP has experienced chemistry events with chloride, hydrazine, and sodium, where inspected parameters have been found at concentrations outside the specified operating range. All conditions were evaluated and corrective actions were instituted, when appropriate, to prevent reoccurrence."

The applicant stated that pre-service nondestructive examination inspections of the STP SGs were performed at the manufacturing site. As a result of the inspection, the applicant stated that 6 tubes in the Unit 2 SGs and 108 tubes in the Unit 1 SGs were plugged.

The applicant reported that, in 2003, during operating cycle 11, a feedwater heater event released foreign material—primarily hundreds of pieces of cable wire strands from a failed feedwater heater tube repair—into Unit 1 SG 1D. STP Technical Specification (TS) 6.8.3.o, “Steam Generator Program,” contains requirements for periodic SG tube inspections, performance criteria for SG tube integrity, provisions for SG tube condition assessments, and repair criteria for SG tube plugging. TS 6.9.1.7, “Steam Generator Tube Inspection Report,” requires the applicant to file a report with the NRC following an outage where an inspection was performed in accordance with TS 6.8.3.o. The applicant’s inspection reports following RFO 1RE13 (October 2006) and RFO 1RE14 (April 2008) describe in more detail the inspections, indications, and evaluations of SG 1D tube integrity with respect to the foreign material introduced during operating cycle 11, and are discussed here.

The applicant’s inspection report, “1RE13 Inspection Summary Report for Steam Generator Tubing,” dated April 2007 (ADAMS Accession No. ML071140087), states that, during the inspections of the 1RE13 RFO, four tubes on the SG 1D cold leg side were identified with wear due to cable wire strand fragments that were from the October 2003 feedwater heater event. Of the four tubes, one tube was plugged due to a wear depth of 44 percent through-wall; because the remaining tubes had wear depths of less than 20 percent, they met the TS 6.8.3.o.c requirements for operability and remained in service. In addition, the report states that two other tubes with volumetric indications greater than 20 percent were plugged. Finally, the report also indicates that, while the condition monitoring assessment limits were met and a normal SG tube integrity inspection frequency of every third outage still applied to SGs 1A, 1B, and 1C, the condition monitoring for SG 1D was only acceptable through the next operating cycle. Therefore, an inspection would need to be performed for SG 1D during the next refueling outage in order to further monitor and evaluate its tube integrity.

The applicant’s inspection report, “1RE14 Inspection Summary Report for Steam Generator Tubing,” dated September 2008 (ADAMS Accession No. ML082820569), states that the 1RE14 inspection plan was developed to inspect and evaluate any tube wear and consequent structural integrity concerns associated with the remaining cable wire strands remaining in SG 1D. The report states that no new tube wear and no corrosion-induced degradation were observed due to the presence of the wire strands, and no tubes required removal from service as a result. The report also states that secondary-side visual inspections identified a total of 220 foreign objects, located primarily toward the bottom of the tube bundle in various locations. The applicant stated that efforts to remove the objects resulted in removal of 150 of them. The applicant also stated that all identified loose parts were removed from the peripheral tube areas of the SG tube bundle and from the annulus region (the transition area from the downcomer to the tube bundle region, near the peripheral SG tubes). The report concludes that, apart from one indication of 9 percent wear (which is below the plugging limit requirement of greater than 40 percent wear), the condition monitoring requirements for SG 1D were satisfied such that any remaining foreign objects would not cause wear to the point that would violate the limits of TS 6.8.3.o over the next two operating cycles.

The staff finds that the applicant’s inspections, evaluations, and actions taken in accordance with TS 6.8.3.o and TS 6.9.1.7 regarding management of SG 1D tube integrity in relation to the foreign material event to be appropriate. The staff notes that removal of the foreign objects in the vicinity of the SG tubes that form the periphery of the tube bundle is important because those areas are where the highest flow and most potential for tube wall degradation exist. The staff also notes that, as indicated in the inspection reports above, the applicant increased its monitoring frequency of SG 1D when condition monitoring assessments projected a wear rate that would not support a normal three-cycle inspection frequency, demonstrating that SG 1D tube integrity associated with any remaining foreign objects is being evaluated and managed in an ongoing, acceptable manner. The staff finds that this operating experience demonstrates that the program is acceptable for managing the aging effects on SG tubes.

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 evaluated and incorporated 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, and review of the applicant's response to RAI B2.1.8-1, the staff finds that the applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

<u>UFSAR Supplement</u>. LRA Section A1.8, as supplemented by letter dated March 10, 2016, and January 5, 2017, 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 is consistent with the recommended description in SRP-LR Table 3.0-1 as revised in LR-ISG-2016-01. The staff also noted that the applicant committed to implement the enhancement to the program (Commitment No. 48) no later than 6 months prior to the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

<u>Conclusion</u>. On the basis of its audit and review of the applicant's Steam Generator Tube Integrity Program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report (as revised in LR-ISG-2016-01) are consistent. 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).

3.0.3.1.4 One-Time Inspection

<u>Summary of Technical Information in the Application</u>. LRA Section B2.1.16, as amended by letter dated June 16, 2011, describes the new One-Time Inspection Program as consistent with GALL Report AMP XI.M32 "One-Time Inspection." The LRA states that the AMP addresses inspections of plant system piping and components to confirm the effectiveness of the Water Chemistry (B2.1.2), Fuel Oil Chemistry (B2.1.14), and Lubricating Oil Analysis (B2.1.23)

programs to manage loss of material, cracking, and reduction of heat transfer. The LRA also states that the AMP proposes to manage these aging effects through the use of one-time inspections.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report, Revision 2. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.M32.

For the "detection of aging effects" program element, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below. The "detection of aging" program element in the GALL Report AMP XI.M32 recommends a sample size of 20 percent of the population or a maximum of 25 components. AMP XI.M32 further states that, otherwise, a technical justification of the methodology and sample size used for selecting components for one-time inspection should be included as part of the program's documentation. However, during its audit, the staff found that the applicant's One-Time Inspection Program does not describe the sample size of inspections. By letter dated September 22, 2011, the staff issued RAI B2.1.16-3 requesting that the applicant provide the sample size, in percent, or the number of components to be applied to this program's sample size.

In its response dated November 21, 2011, the applicant stated that LRA Section B2.1.16 was revised to include a representative sample size of 20 percent of the population up to a maximum of 25 components. The staff finds the applicant's response acceptable because this sample size is adequate for representing those components in the program that may be subject to aging effects. The staff's concern described in RAI B2.1.16-3 (September 22, 2011) is resolved.

Based on its audit and review of the applicant's response to RAI B2.1.16-3 (November 21, 2011), the staff finds that the program elements for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of the GALL Report AMP XI.M32.

Operating Experience. LRA Section B.2.1.16 summarizes operating experience related to the One-Time Inspection Program. The LRA states the following:

> During the 10-year period prior to the period of extended operation, one-time inspections will be accomplished using ASME Code Section V non-destructive examination techniques to identify possible aging effects. ASME Code techniques in the ASME Code Section XI ISI [inservice inspection] Program have proven to be effective in detecting aging effects prior to loss of intended function. Review of STP plant-specific operating experience associated with the ISI Program has not revealed any ISI Program adequacy issues with the STP ASME [Code] Section XI ISI Program. The same non-destructive examination techniques used in the ASME [Code] Section XI ISI Program will be used in the One-Time Inspection Program. Using ASME Code Section V non-destructive examination techniques will be effective in identifying aging effects, if present.

The applicant also stated that industry and plant-specific operating experience will be evaluated and added to the program as it becomes available.

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 evaluated and incorporated 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 RAIs, as discussed below.

This program's LRA commitment list does not include a commitment to perform future review of operating experience to confirm the effectiveness of this new program. By letter dated August 15, 2011, the staff issued RAI B2.1.16-1 requesting that the applicant revise the License Renewal Commitment Table A4-1.

In its response dated September 15, 2011, the applicant stated that in a letter dated June 23, 2011, Commitment No. 29 was revised to include the commitment to evaluate and incorporate new industry and plant-specific operating experience into new AMPs. The applicant also stated that its response dated August 18, 2011, Amendment 3, stated that future operating experience will be reviewed to confirm the effectiveness of AMPs. The staff finds the applicant's response acceptable because this program includes a commitment to review future operating experience, evaluate it, and incorporate it into the program as appropriate, and use operating experience to confirm the effectiveness of the One-Time Inspection Program. This method is now consistent with the GALL Report for new AMPs and their use and application for future operating experience. The staff's concern described in RAI B2.1.16-1 is resolved.

In its response to RAI 4.7.2-1, dated May 12, 2011, the applicant stated that the Unit 1 refueling water storage tank (RWST) has an active leak. The staff noted that, in the documentation associated with the relief request (STPNOC letter and report dated February 22, 2000, ADAMS Accession Nos. ML003686976 and ML003686982), the leak was attributed to a crack in the tank base plate that was caused by stress corrosion cracking (SCC). The staff also noted that LRA Table 3.2.2-4 contains an AMR item for the RWSTs exposed internally to treated borated water; however, loss of material is the only aging effect identified. This aging effect is being managed with the Water Chemistry and One-Time Inspection programs. The staff further noted that, in the absence of inspections to detect cracking on the interior surfaces of the tanks, it cannot conclude that the structural integrity of the RWSTs will not be challenged during the period of extended operation.

By letter dated October 3, 2012, the staff issued RAI B2.1.16-3 requesting that the applicant describe the inspections that will be performed on the interior surfaces of the RWSTs to detect cracking and to specifically characterize the actively leaking defect. The staff also requested that the applicant describe how cracking will be managed for similar stainless steel tanks or to state the basis for why age managing for cracking is not necessary. This issue was previously identified in the SER with Open Items as OI 3.0.3.1.4-1.

In its response dated February 18, 2014, the applicant detailed its activities to characterize the cracking on the Unit 1 RWST, and proposed to manage the aging effect with both one-time and periodic inspections.

Crack characterization. The applicant stated that visual inspections, liquid penetrant examinations, eddy current examinations, and vacuum box leak testing were used to inspect the internal surfaces of the tank bottom during the 2012 fall refueling outage. All identified cracks were repaired, restoring the tank to an ASME Code compliant condition. Metallurgical analysis of crack samples concluded that the SCC originated on the exterior of the tank, in the bottom tank plate, and propagated up through the plate to the tank interior. No cracking was identified in the vertical wall of the tank. Sulfur and chlorides on the crack faces suggested that the exterior bottom plate surface was contaminated with an aqueous solution. The source of the contamination was attributed to groundwater intrusion from a leak in a nearby wall penetration (the Unit 1 RWST is located in the mechanical-electrical auxiliary building below grade level).

Aging management approach. In order to prevent further groundwater intrusion, a berm was constructed around the circumference of the tank, such as exists around the Unit 2 RWST that has not been found to experience cracking. To confirm the effectiveness of the corrective actions, the applicant committed (Commitment No. 47) to perform a one-time inspection of the internal surface of the Unit 1 RWST 5 years prior to entering the period of extended operation. The inspection will use visual, penetrant, and vacuum box testing of the floor bottom and side welds. The applicant also revised the External Surfaces Monitoring Program and UFSAR supplement to state that the external surfaces of the RWSTs will be visually inspected for leakage to detect cracks. The applicant stated that, because the degradation mechanism in the Unit 1 RWST was unique to the environmental condition described above, other indoor stainless steel tanks that are not subject to groundwater intrusion are not susceptible to cracking. Further, there is no plant operating experience that has identified cracking of stainless steel exposed only to indoor air. The staff notes, however, in its response dated June 3, 2014, to RAI 3.0.3-1, the applicant added cracking as an aging effect to LRA Table 3.4.2-6, "Auxiliary Feedwater System," where insulated stainless steel components are being managed for corrosion under insulation.

The staff finds the applicant's response and aging management approach acceptable because the one-time inspection of the interior of the Unit 1 RWST prior to the period of extended operation is capable of confirming that the cracking has been successfully mitigated. In addition, periodic visual inspections to detect leakage on the exterior surfaces of both RWSTs, conducted at least once per refueling cycle, provide reasonable assurance that cracking can be detected throughout the period of extended operation. The staff also finds the applicant's limitation of the above inspection activities to only the RWSTs acceptable, because plant operating experience and the metallurgical analysis of the cracking supports the conclusion that the cracking was unique to the environmental conditions experience by the Unit 1 RWST. The staff's concern described in RAI B2.1.16-3 (October 3, 2012) is resolved, and the associated open item, OI 3.0.3.1.4-1, is closed.

Based on its audit, review of the application, and review of the applicant's response to RAI B2.1.16-1 and RAI B2.1.16-3 (February 18, 2014), the staff finds that the applicant appropriately evaluated plant-specific and industry operating experience. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

<u>UFSAR Supplement</u>. LRA Section A1.16 provides the UFSAR supplement for the One-Time Inspection 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 3.0-1 and noted that it omits sample selection based on materials, examination techniques, evaluation of followup examinations, and the restrictions to when this program may be applied for SCs. The licensing basis for this program 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 August 15, 2011, the staff issued RAI B2.1.16-2 requesting that the applicant resubmit the UFSAR supplement to fully describe this program consistently with the SRP-LR.

In its response dated September 15, 2011, the applicant stated that LRA Appendix A1.16 includes the sample selection of 20 percent of the population up to a maximum of 25 components, and the sample will be made up of the items most susceptible to degradation based on environment and operating experience. LRA Appendix A1.16 also states that a variety of nondestructive examination methods—including visual, volumetric, and surfaces techniques—will be used by the program and that this program will not be used for component inspections with known aging-related degradation mechanisms. LRA Appendix A1.16 further states that the CAP will be used to specify followup inspections if aging effects are detected.

The staff finds the applicant's response acceptable for the following reasons:

- The identified sample size will adequately represent the age managed components.
- The considerations by environment and operation for sample selections now bounds the sample to the most susceptible locations.
- The specified inspection methods will adequately identify the aging effects being managed by this program.
- Restrictions to the program appropriately exclude existing component inspections with known aging-related mechanisms.
- Followup inspections within this program are adequately addressed in the UFSAR supplement Section A1.16.

Therefore, the UFSAR supplement for the One-Time Inspection Program is consistent with the corresponding program description in SRP-LR Table 3.0-1. The staff's concern described in RAI B2.1.16-2 is resolved.

The staff also noted that the applicant committed (Commitment No. 11) to implement the new One-Time Inspection Program prior to entering the period of extended operation for managing aging of applicable components. In addition, the staff noted that the applicant committed (Commitment No. 47) to inspect the internal surface of the Unit 1 RWST 5 years prior to entering the period of extended operation to confirm the effectiveness of the prior corrective actions to address cracking. The staff finds that the information in the UFSAR supplement, as amended by letters dated September 15, 2011, and February 8, 2014, is an adequate summary description of the program.

<u>Conclusion</u>. On the basis of its audit and review of the applicant's One-Time Inspection Program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. 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).

3.0.3.1.5 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

<u>Summary of Technical Information in the Application</u>. LRA Section B2.1.24 describes the new Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification 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 non-EQ cables, connections, and terminal blocks within the scope of license renewal in accessible areas with an adverse localized environment are inspected. The applicant also stated that at least once every 10 years, non-EQ cables, connections, and terminal blocks within the scope of license renewal in accessible areas with an adverse localized environment are visually inspected for embrittlement, melting, cracking, swelling, surface contamination, or discoloration.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.E1.

For the "parameters monitored or inspected" program element, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The "parameters monitored or inspected" program element in GALL Report AMP XI.E1 recommends that an adverse localized environment is a plant-specific condition; therefore, the applicant should clearly define how this condition is determined. Additionally, GALL Report AMP XI.E1 recommends that an adverse localized environment can be identified through the use of an integrated approach such as the review of EQ zone maps that show radiation levels and temperature for various plant areas, consultations with plant staff who are cognizant of plant conditions, use of infrared thermography to identify hot spots on a real-time basis, and review of relevant plant-specific and industry operating experience. However, during the audit, the staff found that the applicant's basis document (STP-AMP-B2.1.24-Revision 1) for the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program states under the same program element that non-EQ cables, connections, and terminal blocks within the scope of license renewal in accessible areas within adverse localized environments are inspected but does not include the methodology for identification of adverse localized environments. By letter dated August 15, 2011, the staff issued RAI B2.1.24-1 requesting that the applicant provide methodology for identification of adverse localized environments.

In its response dated October 10, 2011, the applicant stated the following:

> The STP Plant Data Management System (PDMS) is used to track plant cables. This database contains a listing of cable codes used. The non-EQ cable codes were reviewed to identify the insulating material for each cable type. Any cable codes where the insulating material could not be identified are assumed to be polyvinyl-chloride (PVC). The following are the insulation types used for non-EQ in-scope cables:
>
> - Butyl Rubber (BR)
> - Chlorosulfonated Polyethylene (CSPE/HYP)
> - Cross-Linked Polyethylene (XLPE)
> - Cross-Linked Polyolefin (XLPO)
> - Ethylene Propylene and Ethylene Propylene Rubber (EP/EPR)
> - Polyethylene (PE)
> - Polypropylene (PP)
> - Polyvinyl Chloride (PVC)

- Teflon (FEP)
- Tefzel (ETFE)

> The 60-year service limiting thermal and radiological environment for each cable insulation material was established using Table 10-1 of EPRI-TR1013475, “Plant Support Engineering: License Renewal Electrical Handbook,” Revision 1. The normal plant environment for temperature and radiation are established from the STP Updated Final Safety Analysis Report (UFSAR) Table 3.11-1, “Environmental Conditions.”
>
> Based on the 60-year service limiting thermal conditions for cable insulation material, a graded approach to identifying an adverse localized environment was established. PVC or PE insulated cables have the most limiting 60-year service temperature of 112 degrees Fahrenheit. An adverse localized environment exists where temperatures exceed 112 degrees Fahrenheit within [3 ft] of in-scope cables. If PVC or PE insulated cables are not present, the criterion is raised to 125 degrees Fahrenheit based on the next most limiting insulation material, butyl rubber. If butyl rubber is not present, the next most limiting temperature for all other cable types used is 167 degrees Fahrenheit.
>
> Phenolic material used for fuse block insulation and terminal material has a 60-year service limiting temperature of 231 degrees Fahrenheit. An adverse localized environment exists where temperatures exceed 231 degrees Fahrenheit within [3 ft] of in-scope fuse or terminal boxes.
>
> The 60-year normal radiation dose is determined by multiplying the 40-year cumulative dose in UFSAR Table 3.11-1 by 1.5. The most limiting 60-year normal radiation dose for Teflon insulation material is 5 x 10E4, rads. This dose is established as the radiation criterion for an adverse localized environment for cables containing Teflon. Where Teflon is not present, the next most limiting 60-year normal radiation for all other cable types is 2 x 10E6 rads. Any area exceeding 2 x 10E6 rads is considered an adverse localized environment.
>
> Ultra-violet radiation can cause an adverse localized environment due to exposure to sunlight or fluorescent lighting. Cables exposed to sunlight or located within [3 ft] of a fluorescent light without a protective cover are considered to be in an adverse localized environment. Significant moisture is an adverse localized environment and is defined as periodic exposures to moisture that last for more than a few days. Cables or connections exposed to significant moisture are considered to be in an adverse localized environment.

The staff finds the applicant’s response acceptable because it adequately defined the most limiting condition for adverse localized environment measured in temperature and radiation. The staff’s concern described in RAI B2.1.24-1 is resolved.

<u>Operating Experience</u>. LRA Section B2.1.24 summarizes operating experience related to the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. The applicant stated that it performs periodic insulation resistance tests and has replaced several cables prior to failure. The applicant also stated that regular maintenance inspections have identified insulation cracking, embrittlement, and bubbling, which were repaired with no loss of function.

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 evaluated and incorporated 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 applicant appropriately evaluated plant-specific and industry operating experience. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A1.24 provides the UFSAR supplement for the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program.

The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the applicant committed (Commitment No. 19) to implement the new Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program prior to entering the period of extended operation for managing aging of applicable components.

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. 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).

3.0.3.1.6 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Summary of Technical Information in the Application. LRA Section B2.1.36 describes the new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program as consistent with GALL Report AMP XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," and LR-ISG-2007-02, "Changes to Generic Lessons Learned (GALL) Report Aging Management Program (AMP) XI.E6, 'Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.'" The applicant stated that the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program manages loosening of bolted external connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation to ensure that electrical cable connections not subject to the EQ requirements of 10 CFR 50.49 and within the scope of license renewal are capable of performing their intended function. The applicant also stated that a representative sample of external connections will be tested once prior to the period of extended operation using infrared thermography to confirm that there are no AERMs.

Staff Evaluation: During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared elements one through six of the applicant's program to the corresponding elements of GALL Report AMP XI.E6. For the "parameter monitored or inspected," program element, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

In the basis document STP-AMP-B2.1.36-Revision 2, the applicant states that the "scope of program," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements are consistent with those in the GALL Report, Revision 1. The staff reviewed these program elements and found that they are not consistent with those in the GALL Report, Revision 1. The program elements for which the applicant claimed consistency with the GALL Report, Revision 1, are not consistent with those in the GALL Report, Revision 1, but actually are consistent with the approved LR-ISG-2007-02. LR-ISG-2007-02 was later incorporated into GALL Report AMP XI.E6, Revision 2.

In the "parameters monitored or inspected" program element of the basis document STP-AMP-B2.1.36, Revision 2, the applicant states that the infrared thermography testing is being performed to identify loosening of bolted connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation. The connections associated with cables within the scope of license renewal are splices (butt or bolted), crimp-type ring lugs, connectors, and terminal blocks, as described in the program description in GALL Report AMP XI.E6, Revision 2. The staff believes that loosening of cable connections may also occur in different types of connections and may not only be limited to bolted connections. By letter dated August 15, 2011, the staff issued RAI B2.1.36-1 requesting that the applicant provide technical justification as to why only bolted connections are considered in the inspection sample criteria.

In its response dated October 10, 2011, the applicant stated that the scope of the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program includes both bolted and non-bolted cable connections. The applicant further stated that LRA Sections A1.36 and B2.1.36 and the basis document STP-AMP-B2.1.36 will be revised to clarify the scope of this AMP to include both bolted and non-bolted cable connections. The staff finds the applicant's response acceptable because the scope of Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is now consistent with those in GALL Report AMP XI.E6, Revision 2. The staff's concern described in RAI B2.1.36-1 is resolved.

In the "parameters monitored or inspected" program element of the basis document STP-AMP-B2.1.36, Revision 2, the applicant stated that the technical basis for the sample selected will be documented. GALL Report AMP XI.E6, Revision 2, recommends that 20 percent of the population, with a maximum sample of 25 components, constitutes a representative sample. Otherwise, a technical justification of the methodology and sample size used for selecting components for the one-time test should be included as part of the AMP's site documentation. It was not clear to the staff that the "parameters monitored or inspected" program element was consistent with those in GALL Report AMP XI.E6, Revision 2, because the applicant had not developed the technical basis nor the criteria for sample selection technique. In a letter dated August 15, 2011, the staff issued RAI B2.1.36-2 requesting that the applicant provide technical basis for the sample selection technique.

In its response dated October 10, 2011, the applicant stated that LRA Sections A1.36 and B2.1.36, and the basis document STP-AMP-B2.1-36, Revision 2, will be revised to state that "[t]he selected sample (20 percent of the population, with a maximum of 25) to be tested, is based upon application (medium and low voltage), circuit loading (high or low load), and environment (temperature, high humidity, vibration, etc.)."

The staff finds the applicant's response acceptable because the applicant clearly identified the selected sample size criteria, which are consistent with those in GALL Report AMP XI.E6, Revision 2. The staff's concern described in RAI B2.1.36-2 is resolved.

Based on its audit, and review of the applicant's responses to RAIs B2.1.36-1 and B2.1.36-2 of the applicant's Electrical Cable Connection Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.E6, Revision 2.

<u>Operating Experience</u>. LRA Section B2.1.36 summarizes operating experience related to the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. The applicant stated that STP routinely performs infrared thermography on electrical components and connections. A review of the plant operating experience identified a small number of scans where electrical cable connections showed a thermal anomaly. No loss of equipment intended function has occurred because of these thermal anomalies. The applicant also stated that the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is a new program; therefore, plant-specific operating experience to confirm the effectiveness of the program is not available. The applicant further stated that plant-specific operating experience was reviewed to ensure that the operating experience discussed in the corresponding GALL Report program is bounding (i.e., that there is no unique, plant-specific operating experience in addition to that in the GALL Report). The applicant stated that as additional industry and plant-specific applicable operating experience becomes available, it will be evaluated and incorporated into the program through the STP condition reporting and operating experience programs.

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 evaluated and incorporated 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 applicant appropriately evaluated plant-specific and industry operating experience. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A1.36 provides the UFSAR supplement for the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program.

The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the applicant committed (Commitment No. 28) to implement the new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program prior to entering the period of extended operation for managing aging of applicable components.

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. 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).

3.0.3.1.7 Environmental Qualification (EQ) of Electrical Components

Summary of Technical Information in the Application. LRA Section B3.2 describes the existing Environmental Qualification (EQ) of Electrical Components Program as consistent with GALL Report AMP X.E1, "Environmental Qualification (EQ) of Electrical Components." The applicant stated that its Environment Qualification (EQ) of Electrical Components Program includes and identifies electrical components that are important to safety and that could be exposed to harsh environment accident conditions, consistent with the exemption of low safety significance (LSS) and non-risk significant (NRS) EQ components that have been granted. The applicant also stated that, if qualification cannot be extended by reanalysis, the component is refurbished or replaced prior to exceeding the period for which the current qualification remains valid.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP X.E1.

For the "scope of program" program element, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The "scope of program" program element in GALL Report AMP X1.E2 manages the aging of electrical cables and connections used in circuits with sensitive, high-voltage, low-level current signals—such as radiation monitoring and nuclear instrumentation—installed in adverse localized environments caused by temperature, radiation, or moisture. However, during its audit, the staff found that the applicant's Environmental Qualification (EQ) of Electrical Components Program will be used to manage the aging of electrical cables and connections used in circuits with sensitive, high-voltage, low-level current signals. These instrumentation electrical cables and connections, which would normally be included in GALL Report AMP XI.E2, are in scope of LRA AMP B3.2, "Environmental Qualification (EQ) of Electrical

Components Program." By letter dated August 15, 2011, the staff issued RAI B3.2-1 requesting that the applicant identify cables and connections used in circuits with sensitive, high-voltage, low-level current signals that are in scope of LRA AMP B3.2.

In its response dated October 10, 2011, the applicant stated that its review identified certain components with sensitive, high-voltage, low-level current signals that are environmentally qualified to meet the requirements of 10 CFR 50.49 and within the scope of license renewal under its LRA Appendix B3.2, Environmental Qualification (EQ) of Electrical Components Program. The applicant stated that cables, connections, and Raychem tubing in the following equipment are in this category: (1) excore source range and power range nuclear detector cables; (2) SG blowdown high-range radiation detectors; (3) main steamline high-range radiation detectors; and (4) reactor containment building high-range area radiation detectors.

The staff finds the applicant's response acceptable because the applicant adequately identified cables and connections used in circuits with sensitive, high-voltage, low-level current signals that are in scope of LRA AMP B3.2. The staff's concern described in RAI B3.2-1 is resolved.

The staff reviewed EQ calculation No. E43321 on Rosemount transmitter Models 1153 Series B, 1153 Series D, and 1154. NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," describes the use of the linearized Arrhenius equation "to derive an accelerated aging time by inputting an aging temperature, the desired component life, and ambient temperature." The applicant used the Arrhenius equation method in its calculation. The applicant's calculation revises the qualified life based on actual temperature data from the past years in Unit 1 containment. The qualified life for the Rosemount transmitters located in containment has been recalculated using the actual temperature data, and—in most cases—the qualified life for these transmitters has been increased significantly. The qualified life of the electronic boards inside the Rosemount transmitters has also been recalculated, and—in most cases—the qualified life for the electronic boards has also been increased significantly. As stated in GALL Report AMP X.E1, Arrhenius methodology is an acceptable method for revising the qualified life based on actual temperature data.

<u>Operating Experience</u>. LRA Section B3.2 summarizes operating experience related to the Environmental Qualification (EQ) of Electrical Components Program. The applicant described several condition reports that represent samples of the program operating experience. This includes "update environmental qualification documentation for the new core exit thermocouple connector assemblies" and "develop and perform a sampling assessment of environmental qualification components in harsh environments to determine if qualifications match environment."

The staff also reviewed the Equipment Qualification Self-Assessment, dated 2005. This report detailed self-assessments of the STP EQ Program, which outline strengths and deficiencies of the program. Deficiencies include an incorrect description of the number of items in the Equipment Qualification Master List and a calculation that was revised without the standalone calculation being revised. Opportunities for improvement include enhancing equipment qualification procedures to more fully define owners and responsibilities of maintenance of equipment qualification databases and identifying and documenting distinct training requirements for personnel in key positions within the Equipment Qualification Program.

The staff reviewed tracking condition reports and deficiency condition reports that were generated as a result of 2005 EQ self-assessment and confirmed that all improvements have been completed.

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 evaluated and incorporated 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 applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A2.2 provides the UFSAR supplement for the Environmental Qualification (EQ) of Electrical Components Program.

The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1.

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Environmental Qualification (EQ) of Electrical Components Program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. 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).

3.0.3.1.8 Concrete Containment Tendon Prestress

Summary of Technical Information in the Application. LRA Section B3.3 describes the existing Concrete Containment Tendon Prestress Program as consistent with GALL Report AMP X.S1, "Concrete Containment Tendon Prestress." The LRA states that the Concrete Containment Tendon Prestress Program is contained within the ASME Code Section XI Subsection IWL Program and manages the loss of tendon prestress aging effect in the post-tensioning system. The program is consistent with requirements of 10 CFR 50.55a, including the supplemental requirements.

The LRA states that the containments are prestressed concrete, hemispherical dome-on-a-cylinder structures with a steel membrane liner and a flat basemat. Post-tensioned tendons permit the structures to withstand design basis accident internal pressures.

The program's acceptance criterion is that measured tendon prestress losses must come close enough to the predicted values to provide high confidence that the prestress forces will remain above the minimum design values through the life of the plant. The design acceptance criterion is ensured by surveillance program acceptance criteria that are consistent with ASME Code

Section XI Subsection IWL-3221.1. In accordance with 10 CFR 50.55a, the third interval Inservice Inspection Program for Subsection IWL will be conducted in accordance with the requirements of the 2004 edition (no addenda) of ASME Code Section XI.

The LRA states that, in accordance with Regulatory Guide (RG) 1.35, “Inspection of Ungrouted Tendons in Prestressed Concrete Containments,” April 1979, proposed Revision 3, the examination schedule for Unit 1 is 1, 5, and 10 years after the initial structural integrity test (SIT), and every 10 years thereafter; for Unit 2 the schedule is 1, 5, and 15 years after the initial SIT and every 10 years thereafter.

The applicant’s program inspects a random sample of tendons from each tendon group during each inspection interval to confirm that the acceptance criteria are met; therefore, the prestressing forces will remain above the minimum required values (MRVs) for the next inspection interval. At each inspection, the program recalculates the regression analysis trend lines for the horizontal and vertical tendons for each unit based on the individual tendon forces.

Staff Evaluation. During its audit, the staff reviewed the applicant’s claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant’s program to the corresponding program elements of GALL Report AMP X.S1.

Based on its audit of the applicant’s Concrete Containment Tendon Prestress Program, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP X.S1.

Operating Experience. LRA Section B3.3 summarizes operating experience related to the Concrete Containment Tendon Prestress Program. The LRA states that STP tendon inspections to date have shown no evidence of significant corrosion or other effects that might damage wires, minimum wire breakage (after initial installation), and no accelerated loss of prestress due to high temperatures or other causes.

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 evaluated and incorporated operating experience related to this program.

The “operating experience” program element in GALL Report AMP X.S1 recommends that the applicant’s AMP for concrete containments consider the degradation concerns described in the NRC’s generic communications, including NRC Information Notice (IN) 99-10, “Degradation of Pre-stressing Tendon Systems in Pre-stressed Concrete Containments,” dated October 7, 1999. Based on information provided in the LRA, review of the applicable calculations during the audit, and interviews with the applicant, it was not clear to the staff if the effect of high temperature on the tendon prestressing forces, as described in IN 99-10, has been considered by the applicant as part of its AMP. This resulted in the issuance of an RAI. Discussion of the RAI and the staff’s review is located in Section 3.0.3.2.23, ASME Code Section XI, Subsection IWL.

During its review, the staff identified operating experience that required additional clarification and resulted in the issuance of RAIs, as discussed below.

The staff noted in program documentation that there was a scheduled year-3 tendon surveillance for Unit 1, but it could not find results of a year-3 tendon lift-off examination. In a letter dated August 15, 2011, the staff issued RAI B3.3-2, Part 2, and requested that the applicant explain why there are no results for the year-3 tendon surveillance and to describe the tendon surveillance schedule in accordance with ASME Code IWL-3221.1. By letter dated October 10, 2011, the applicant stated that Units 1 and 2 were licensed to RG 1.35, which allows a site with two plants to use a 1-, 5-, and 10-year (and every 10 years thereafter) schedule for each containment, provided the SIT for the second containment was performed within 2 years of the first. The applicant adapted ASME Code IWL starting with the year-15 surveillance. In addition, in a teleconference on January 4, 2012, the applicant clarified that the year-3 examination noted by the staff was a visual examination only and that no tendon lift-off measurements were conducted. The staff finds this response acceptable because the applicant appropriately applied the provisions of RG 1.35 for sites with multiple containments and now follows the ASME Code IWL schedule requirements. The staff's concern stated in RAI B3.3-2, Part 2, is resolved.

The staff reviewed the applicant's inservice surveillance of containment post-tensioning system procedure and noted that it defines the acceptance criteria for an individual tendon as having a prestress force greater than 95 percent of predicted force. LRA Section B3.3 states that 2 of the 140 tendon lift-off tests did not meet acceptance criteria for the Containment Tendon Prestress Program. The staff noted that program information reviewed onsite indicated that both of the deficient tendon examination results occurred in Unit 2, but LRA Section B3.3 states that one deficient tendon was found in Unit 2 and one in Unit 1. In addition, the staff noted that the deficiencies were found in the year-1 and year-5 surveillance inspections. LRA Section B3.3 describes the issue but does not state what, if any, corrective actions were taken for the deficient tendons. Program documentation reviewed during the staff's onsite audit indicated that, despite finding deficiencies with the year-1 and year-5 surveillances, no corrective actions were taken until the year-10 surveillance. In its August 15, 2011, RAI B3.3-2, Parts 1 and 3, the staff requested that the applicant resolve the discrepancy between the LRA and basis documents as to where the deficient tendons were found and provide information regarding what corrective actions were taken and when they were taken. The staff also asked the applicant to provide justification for delaying the corrective actions.

In its response, dated October 10, 2011, the applicant clarified that the LRA is correct in that there was one deficiency recorded for Unit 1 (year-5 inspection) and one for Unit 2 (year-1 inspection). The applicant also stated that corrective actions were implemented, as described in STP Licensee Event Report (LER) 1-98-001. The staff reviewed LER 1-98-001 and noted that the deficient tendons were found while the applicant was preparing for the year-10 surveillance. The staff noted that there was an error found in the calculations to determine containment structure post-tension stress levels. When the applicant realized the error, it reanalyzed the results of all of the previous tendon surveillances, which resulted in the two aforementioned measurements to fall outside of the tolerance band for acceptability of prestressing force measurements.

In its RAI response, the applicant stated that for each of the two affected tendons, the tendon was retested, and two additional adjacent tendons were tested, which is consistent with ASME Code IWL-3221.1 requirements, even though the plant was still following RG 1.35. The lift-off measurement results for the additional surveyed tendons met the acceptance criteria of the program. The applicant stated that administrative corrective actions were implemented, including revision of the calculation used to predict tendon lift-off forces and revision to the calculation procedure to contain more stringent requirements for calculation review. The staff finds the responses to RAI B3.3-2, Parts 1 and 3, acceptable because corrective actions were taken per the program requirements and code provisions in a timely manner once the problem was identified, and the program was augmented to better ensure accuracy in the calculation of expected tendon stresses. The staff's concerns stated in RAI B3.3-2, Parts 1 and 3, are resolved.

During its review of LRA Section B3.3, the staff noted that the applicant's Inservice Surveillance of Containment Post-tensioning System Program procedure sets a limit to the volume of grease voids that can exist in any one tendon. The LRA states that grease voids in excess of surveillance requirements were found during the Unit 1 year-3, -5, and -10 inspections, and Unit 2 year-3, -5, and -15 inspection. The LRA does not describe any corrective actions taken, even though grease voids were found to exceed the acceptance limits. By letter dated August 15, 2011, the staff issued RAI B3.3-3 requesting that the applicant describe what, if any, corrective actions were taken as a result of discovering conditions that did not meet acceptance criteria.

In its October 10, 2011, letter, the applicant responded that each time grease voids in excess of surveillance requirements were discovered, they were reported to the NRC by letter, including detailed discussion of the condition and the reasons for concluding that the condition was acceptable. The applicant further stated that the grease voids were determined to be the result of grease shrinkage, and the exterior walls of the containment were visually examined to confirm that there were no indications of grease leakage or seepage from the tendon ducts. The applicant also stated that it examined wires pulled during the surveillance and confirmed that the grease shrinkage had no impact on the corrosion protection of the affected tendons. The corrective actions taken were only to refill the voids with grease. The staff finds this response acceptable because corrective actions were taken in response to the discovery of deficient conditions with regard to grease voids. In each instance where grease voids were found, actions were taken to evaluate the impact on the corrosion protection function of the grease by examining wires in the affected areas. The staff addresses operating experience regarding grease leakage in Section 3.0.3.2.23, ASME Code Section XI, Subsection IWL. The staff's concern stated in RAI B3.3-3 is resolved.

Based on its audit and review of the application and review of the applicant's responses to RAIs B3.3-2 and B3.3-3, the staff finds that the applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

<u>UFSAR Supplement</u>. LRA Section A2.3 provides the UFSAR supplement for the Containment Tendon Prestress Program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

<u>Conclusion</u>. On the basis of its audit and review of the applicant's Concrete Containment Tendon Prestress Program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. 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 AMPS That Are Consistent with the GALL Report with Exceptions or Enhancements

In LRA Appendix B, the applicant identified the following AMPs that were, or will be, consistent with the GALL Report, with exceptions or enhancements:

- Water Chemistry
- Reactor Head Closure Studs
- Boric Acid Corrosion
- Flow-Accelerated Corrosion
- Bolting Integrity
- Open-Cycle Cooling Water System
- Closed-Cycle Cooling Water System
- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems
- Fire Protection
- Fire Water system
- Fuel Oil Chemistry
- Reactor Vessel Surveillance
- Selective Leaching of Materials
- Buried Piping and Tanks Inspection
- One-Time Inspection of ASME Code Class 1 Small-Bore Piping
- External Surfaces Monitoring Program
- Flux Thimble Tube Inspection
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Lubricating Oil Analysis
- Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
- Metal Enclosed Bus
- ASME Section XI, Subsection IWE
- ASME Section XI, Subsection IWL
- ASME Section XI, Subsection IWF
- 10 CFR Part 50, Appendix J
- Structures Monitoring Program
- RG 1.127 Inspection of Water-Control Structures with Nuclear Power Plants

- Metal Fatigue of Reactor Coolant Pressure Boundary
- Masonry Wall Program

3.0.3.2.1 Water Chemistry

Summary of Technical Information in the Application. LRA Section B2.1.2 describes the existing Water Chemistry Program as consistent, with an enhancement, with GALL Report AMP XI.M2, "Water Chemistry." The LRA states that the AMP addresses monitoring and control of the chemical environment in the RCS, related auxiliary systems, the SG secondary side, and the secondary cycle systems to manage the aging effects associated with corrosion mechanisms and SCC. The LRA also states that the AMP proposes to manage the effects of loss of material, cracking, reduction of heat transfer, and wall thinning aging effects by limiting the concentration of chemical species to inhibit degradation and by adding chemical species to inhibit degradation by their influence on pH and dissolved oxygen levels. The One-Time Inspection Program (B2.1.16) is used to confirm the effectiveness of the Water Chemistry Program in low flow areas where the program is consistent with, and based upon, EPRI 1014986, "PWR Primary Water Chemistry Guidelines," Volumes 1 and 2, Revision 6, for primary water chemistry, and EPRI 1016555, "PWR 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 compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.M2.

The staff also reviewed the portions of the "monitoring and trending" program element associated with the enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this enhancement follows.

Enhancement 1. LRA Section B2.1.2 states an enhancement to the "monitoring and trending" program element. In this enhancement, the applicant stated that the procedures will be enhanced to include a statement that the sampling frequency for the primary and secondary water systems is temporarily increased whenever corrective actions are taken to address an abnormal chemistry condition for action level parameters and that this increased sampling is used to confirm that the desired condition has been achieved. When it is achieved, the sampling frequencies are returned to the EPRI recommended frequencies. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M2 and finds it acceptable because, when it is implemented, it will be consistent with the program elements and methodology found in the GALL Report AMP XI.M2, "Water Chemistry Program."

Summary. Based on its audit of the applicant's Water Chemistry Program, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M2. In addition, the staff reviewed the enhancement associated with the "monitoring and trending" program element and finds that, when implemented, it will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.2 summarizes operating experience related to the Water Chemistry Program. The LRA states that out of specification (OOS) incidents have occurred for primary and secondary water chemistry parameters. The OOS occurrences were transients, and all of the OOS values were returned to within specification in accordance with the required time intervals. OOS water chemistry events have occurred more often for the secondary systems than for the primary systems.

Two operating experiences described in the LRA, as summarized below, were related to occurrences of high chemistry transport in the plant where the existing management program identified the issues, took corrective action, and prevented recurrences.

The LRA states that, in 1998, secondary plant sources of copper were documented, which led to replacing all feedwater heater and moisture separator reheater divider plate aluminum bronze nuts with A453 Grade 660 steel nuts.

In a second operating experience described in the LRA, SG tube sheet sludge lancing performed during outages removed 73 lb in one instance and 48 lb in another, with very low returns (typically less than 10 percent) from the sludge collector boxes. The LRA states that such returns represent a small fraction of the iron that is fed to the SGs. The LRA also states that most of the iron fed to the SGs was absorbed into the tube oxide layers. The LRA further states that condensate and feedwater piping are expected to be an insignificant source for iron transport to the SGs. However, an EPRI-sponsored study at the station in 2000 found it to be a significant source of corrosion iron. The LRA states that STP conducted corrosion product transport studies, which confirmed that condensate and feedwater piping contribute significantly to iron transport values.

The LRA states that the plant's iron is at expected levels considering plant design and operational chemistry control. During the audit, the applicant stated that, during each plant cycle, an iron transport analysis and evaluation is completed. It is then reviewed to monitor, correct, and then adjust the program's iron to control chemistry transport within the plant chemistry.

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 evaluated and incorporated 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 applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

<u>UFSAR Supplement</u>. LRA Section A1.2 provides the UFSAR supplement for the Water Chemistry Program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1.

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

The staff also noted that the applicant committed (Commitment No. 1) to enhance the existing Water Chemistry Program prior to the period of extended operation by including a statement to the procedures that sampling frequency for primary and secondary water systems will be temporarily increased whenever corrective actions are taken to address an abnormal water chemistry condition. In a letter dated June 3, 2014, the applicant informed the NRC that all activities associated with Commitment No. 1 were completed.

Conclusion. On the basis of its audit and review of the applicant's Water Chemistry Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancement and confirmed that implementation of Enhancement 1 and Commitment No. 1, of LRA Table A4-1 makes the AMP adequate to manage the applicable aging effects. 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).

3.0.3.2.2 Reactor Head Closure Studs

Summary of Technical Information in the Application. LRA Section B2.1.3, as amended by RAI responses, describes the existing Reactor Head Closure Studs Program as consistent, with exceptions and an enhancements, with GALL Report AMP XI.M3, "Reactor Head Closure Studs." The Reactor Head Closure Studs Program manages cracking and loss of material exposed to air with reactor coolant leakage by conducting ASME Code Section XI inspections of RV flange stud hole threads, reactor head closure studs, nuts, washers, and bushings. The program includes periodic visual, surface, and volumetric examinations of RV flange stud hole threads, reactor head closure studs, nuts, washers, and bushings and performs visual inspections of the RV flange closure during primary system leakage tests. The program follows the preventive measures in RG 1.65, Revision 1, "Material and Inspection for Reactor Vessel Closure Studs." In addition, the program uses lubricants on reactor head closure stud threads after reactor head closure stud, nut, and washer cleaning and examinations are complete. The lubricants are compatible with the stud material and operating environment and do not include MoS_2, which is a potential contributor to SCC.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.M3. For the "scope of program" program element, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

LRA Section B2.1.3 states that the program manages cracking and loss of material by conducting ASME Code Section XI inspections of RV flange stud hole threads, reactor head closure studs, nuts, washers, and bushings. Consistently, LRA Table 1, item 3.1.1.71, indicates that the applicant uses the Reactor Head Closure Studs Program to manage cracking and loss of material of high-strength low-alloy steel closure head stud assembly. In comparison, LRA Table 3.1.2-1 includes AMR items to manage cracking and loss of material of "RV closure head bolts"; however, LRA Table 3.1.2-1 does not clearly indicate that the AMR items include the other reactor head closure stud bolting components such as RV head closure nuts, washers, and bushings, as addressed in LRA Section B2.1.3. Furthermore, the staff noted that the STP site documentation regarding the screening of the RV components for aging management includes only 72 RV head closure bolts, but it does not include any other RV head closure bolting component such as nuts, washers, bushings, or threads in the RV flange.

By letter dated August 15, 2011, the staff issued RAI B2.1.3-3, requesting that the applicant describe whether the AMR items addressed in LRA Table 3.1.2-1 to manage cracking and loss of material of reactor head closure stud bolting include all the closure studs, nuts, washers, bushings, and flange threads. In addition, the applicant was requested to revise the LRA and STP site documentation, consistent with the applicant's response to this RAI.

In its response dated September 15, 2011, the applicant stated that the AMR items for component type "RV Closure Head Bolts" in LRA Table 3.1.2-1, which manage cracking and loss of material, include the closure studs, nuts, washers, and bushings. The applicant also stated that the component type in LRA Table 3.1.2-1 or the "RV Closure Head Bolts" will be revised to "RV Closure Head Bolting Assemblies." However, the staff finds that although the applicant stated that the component type in LRA Table 3.1.2-1 will be revised to "RV Closure Head Bolting Assemblies," the applicant did not provide a specific revision made to LRA Table 3.1.2-1 or the STP site document for component screening for this program. By letter dated November 15, 2011, the staff issued RAI B2.1.3-3a requesting that the applicant revise LRA Table 3.1.2-1 consistent with the scope of program, including "RV closure head bolts" and the other reactor head closure bolting components. The staff also requested that the applicant revise the STP site document, consistent with the scope of program.

In its response dated December 15, 2011, the applicant stated that the "South Texas Project Component Summary Screening Report, ID No. RCVI, Reactor Vessel and Internals," component type "RV Closure Head Bolts," is revised to "RV Closure Head Bolting Assemblies." The applicant also confirmed that LRA Table 3.1.2-1 component type "RV Closure Head Bolts" is revised to "RV Closure Head Bolting Assemblies." In addition, the staff noted that the applicant supplemented its previous response to RAI B2.1.3-3 and the revisions clarify that the RV closure head bolting assemblies are the components of interest for which the applicant's program manages aging. The staff finds the applicant's response acceptable because the LRA and site document are appropriately revised to be consistent and that the applicant's program manages the aging effect of the RV closure head bolting assemblies, including the RV closure head bolts and the other closure bolting components. The staff's concerns described in RAIs B2.1.3-3 and B2.1.3-3a are resolved.

The staff also reviewed the portions of the "scope of program" and "corrective action" program elements associated with exceptions to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these exceptions follows.

Exception 1. LRA Section B2.1.3 states an exception to the "scope of program" program element. In this exception, the applicant stated that, while RG 1.65 (Revision 0, issued October 1973) states that stud bolting material should not exceed an ultimate tensile strength of 170 ksi, one closure head insert has an ultimate tensile strength of 174.5 ksi. The applicant also stated that it credits inservice inspections that are within the scope of this AMP, which are implemented in accordance with the STP Inservice Inspection Program, Examination Category B-G-1 requirements, as the basis for managing cracking in these components. The applicant further stated that the studs, nuts, and washers are coated with a lubricant, which is compatible with the stud materials.

In comparison, GALL Report, Revision 2, AMP XI.M3, “Reactor Head Closure Stud Bolting,” references RG 1.65, Revision 1, “Materials and Inspections for Reactor Vessel Closure Studs,” issued in April 2010. The guidance in RG 1.65, Revision 1, recommends using bolting materials that have a measured yield strength not exceeding 150 ksi (as opposed to an ultimate tensile strength exceeding 170 ksi) because bolting materials with a yield strength below this value are not susceptible to SCC. In its review, the staff noted that UFSAR Tables 5.3-5 and 5.3-6 describe the RV fastener material properties of Units 1 and 2, respectively, including both the yield strength data and the ultimate tensile strength data of the reactor head closure stud bolting material. The staff also noted that several bars of the closure stud bolting material have ultimate yield strength values greater than 150 ksi, up to 158 ksi. Because of the concern that SCC could occur in materials with these values, the staff needed to confirm whether the applicant adequately considered the effect of yield strength on the potential for SCC in its AMP.

By letter dated August 15, 2011, the staff issued RAI B2.1.3-1, requesting that the applicant address the issue of susceptibility to SCC from the perspective of yield strength regarding its reactor head closure stud bolting materials, particularly those that exceed 150 ksi. The applicant was also requested to clarify whether its program has a provision to preclude the use of closure stud bolting materials with measured yield strengths exceeding 150 ksi. The staff further requested that if the program does not have such a provision, the applicant should justify the adequacy of its program to manage cracking due to SCC of the high-strength material.

In addition, the staff requested that as part of the justification, the applicant describe whether its operating experience indicates that the closure stud bolting has been exposed to reactor coolant leakage and how its program manages the potential exposure of closure stud bolting to borated water and an environment that may facilitate SCC. Furthermore, the staff requested that the applicant describe whether its program precludes future addition of reactor head closure stud bolting components with yield strengths exceeding 150 ksi.

In its response dated September 15, 2011, the applicant stated that several components in the RV closure head stud assemblies have measured yield strength levels greater than or equal to 150 ksi. The applicant indicated that the program manages cracking and loss of material in the RV closure head stud assemblies and includes visual and volumetric examinations that are performed in accordance with ASME Code Section XI, Subsection IWB, requirements and as recommended in RG 1.65. The applicant also indicated that procedures require the studs, nuts, and washers to be removed and placed in storage racks during preparation for refueling to prevent exposure to the borated refueling cavity water and that the stud holes in the reactor flange are sealed with special plugs, thus preventing leakage of the borated refueling water into the stud holes.

The applicant further stated that, to date, its operating experience has shown that the RV head stud assemblies have not been exposed to borated reactor coolant leakage, and there have been no cases of cracking of these components.

In its response, the applicant also stated that the program will be enhanced to preclude the future use of stud assembly material having a measured yield strength greater than or equal to 150 ksi, with the exception of the head closure bolting components currently in use or the spare components currently onsite. The applicant further stated that LRA Appendix B2.1.3 and the LRA basis document for this program will be revised to preclude the use of replacement closure stud assemblies fabricated from material with a measured yield strength greater than or equal to 150 ksi, except that use of installed components and any spare components currently onsite will be allowed. The applicant stated that allowing future use of the existing spare reactor head closure stud assemblies is justified based on plant-specific operating experience and the inspection aspects of the AMP discussed above.

During its review, the staff noted that the applicant did not provide specific revisions made to the LRA or program basis document in order to confirm that the program enhancement has been incorporated. By letter dated November 15, 2011, the staff issued RAI B2.1.3-1a requesting that the applicant revise the LRA and program basis document to preclude the use of replacement closure bolting material with a yield strength level greater than or equal to 150 ksi, consistent with its RAI response.

In its response dated December 15, 2011, the applicant confirmed that LRA Section B2.1.3 and the program basis document were revised to preclude the use of replacement closure bolting material with a yield strength level greater than or equal to 150 ksi, consistent with the response to RAI B2.1.3-1. The staff also noted that, by letter dated November 4, 2011, the applicant supplemented its previous response and provided the revisions to the LRA and program basis document. The staff's concerns described in RAI B2.1.3-1a is resolved.

During its review of the applicant's proposed exception to the recommendations of the GALL Report, the staff noted that the 150 ksi yield strength criterion is intended to be a threshold to identify whether the bolting material is susceptible to SCC (i.e., whether SCC is an applicable concern). In cases where this threshold is exceeded, the staff needs to confirm that the applicant's proposed AMP includes adequate inspections to detect and manage cracking due to SCC. As indicated by the applicant in its responses, its AMP performs the appropriate inspections necessary to detect the occurrence of SCC in accordance with the ASME Code Section XI requirements and is consistent with the GALL Report's recommendations for detection under AMP XI.M3. Therefore, the staff's concern regarding the applicant's closure studs and SCC are satisfied because these inspections are effective in preventing, detecting, and managing loss of material and cracking of the reactor head closure bolting components. In addition, the staff also noted that the adequacy of the applicant's program is supported by the applicant's operating experience, which indicates that there have been no cases of cracking of these components. The staff's concern described in RAI B2.1.3-1 is resolved.

Exception 2. LRA Section B2.1.3 states an exception to the "corrective actions" program element. In this exception, the applicant stated that NUREG-1801, Section XI.M3, specifies the use of RG 1.65 requirements for closure stud and nut material. The applicant also stated that STP uses SA-540, Grade B-24 (as modified by Code Case 1605) stud material. The applicant further stated that the use of this material has been found acceptable to the NRC for this application with limitations in accordance with RG 1.85, "Materials Code Case Acceptability, ASME [Code] Section III, Division 1."

During its review, the staff noted that RG 1.85, "Materials Code Case Acceptability, ASME [Code] Section III, Division 1," was withdrawn in June 2003, as indicated in the NRC letter, "Withdrawal of Regulatory Guide 1.85," dated June 10, 2004. The NRC letter also states that Revision 32 of RG 1.84, "Design, Fabrication, and Materials Code Case Acceptability, ASME [Code] Section III," which was issued in June 2003, contains comprehensive guidance on all Section III Code Cases, including those oriented to materials and related testing in Division 1, which were previously contained in RG 1.85. The NRC letter further states that the withdrawal of RG 1.85 does not alter any prior existing licensing commitments based on its use. In addition, the staff noted that RG 1.84, Revision 32, issued June 2003, indicates that it lists all Section III Code Cases that the NRC has approved for use, and ASME Code Case 1605 was unconditionally approved by the NRC.

The staff reviewed this exception against the corresponding program element in GALL Report AMP XI.M3 and the approved guidance of the NRC. Based on its review, the staff finds the exception acceptable because RG 1.65 approves the use of SA-540, Grade B-24, for closure stud and nut material, and RG 1.84 approves the use of ASME Code Case 1605 that addresses modified SA-540, Grade B-24, such that the program is consistent with the NRC guidance for the materials of reactor head closure bolting.

Enhancement 1. LRA Section B2.1.3, as amended by the applicant's letter dated November 4, 2011, addresses an enhancement to the "scope of program" program element. In this enhancement, the applicant stated that procedures will be enhanced to preclude future use of replacement closure stud assemblies fabricated from material with an actual measured yield strength greater than or equal to 150 ksi and that the use of currently installed components and any spare components currently onsite is allowed.

The staff reviewed this enhancement against GALL Report AMP XI.M3 and finds it acceptable because it will preclude the use of high-strength replacement bolting components that are susceptible to SCC, consistent with the recommendation in the GALL Report. In addition, the staff finds that the applicant's program includes program attributes that are effective in preventing, detecting, and managing loss of material and cracking of the reactor head closure bolting components, as described in the staff's evaluation regarding Exception 1.

Enhancement 2. LRA Section B2.1.3, as amended by the applicant's letter dated December 15, 2011, addresses an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that procedures will be enhanced to perform a remote VT-1 examination of stud insert #30 (also called stud hole insert #30) in Unit 2 only, concurrent with the volumetric examination once every 10 years, to confirm no additional loss of bearing surface area. The applicant also indicated that this enhancement 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.M3. The staff also reviewed the proposed implementation schedule for the visual examination in consideration of the plant-specific operating experience regarding the partial indentation on the load-bearing surfaces of stud insert #30 of Unit 2. The staff's evaluation of the implementation schedule is described in detail in the following section regarding the applicant's operating experience.

The staff noted that the applicant's proposed inspection schedule for the visual examination (once every 10 years during the period of extended operation) may delay the first visual examination up to 10 years of operation after entering the period of extended operation. In such a scenario, the proposed schedule would not confirm an absence of additional reduction in bearing surfaces and aging degradation in the stud insert prior to the period of extended operation; therefore, a necessary corrective action may not be performed in a timely manner.

By letter dated March 21, 2012, the staff issued RAI B2.1.3-2b requesting that the applicant justify the adequacy of the proposed inspection schedule. The staff also requested that the applicant consider that the proposed schedule for successive visual inspections of stud insert #30, which is once every 10 years during the period of extended operation, may delay the visual examination as late as 10 years after entering the period of extended operation.

In its response dated April 17, 2012, the applicant amended the implementation schedule for this enhancement such that a remote VT-1 examination of stud insert #30, concurrent with the volumetric examination, will start in the current (third) 10-year ASME Section XI inspection interval. The staff noted that LRA Section B2.1.1 indicates that Unit 2 entered its third inservice inspection interval on October 19, 2010, which indicates that the proposed remote VT-1 and volumetric examinations would occur by 2020 at the latest. The staff finds the applicant's response acceptable because the applicant will perform visual and volumetric examinations of stud insert #30, which are adequate to ensure no additional loss of the bearing surface area, and the implementation schedule of this enhancement will be within the current (third) inservice inspection interval prior to the period of extended operation in a timely manner. The staff's concern regarding the inspection schedule described in RAI 2.1.3-2b is resolved.

The staff reviewed this enhancement against GALL Report AMP XI.M3 and finds it acceptable because the visual examination of stud insert #30, which will start in the current (third) inservice inspection interval, concurrent with the volumetric examination, is adequate to ensure the absence of an additional bearing surface reduction and aging degradation in the stud insert for the period of extended operation.

Operating Experience. LRA Section B2.1.3 summarizes operating experience related to the Reactor Head Closure Studs Program. The applicant stated that review of plant-specific operating experience has not revealed any program adequacy issues with the Reactor Head Closure Studs Program for RV closure studs, nuts, washers, bushings, and flange thread holes. The applicant also stated that no cases of cracking due to SCC or IGSCC have been identified with STP RV studs, nuts, washers, bushings, and flange stud holes.

During its review of applicant's operating experience, the staff noted that a work order dated April 12, 2007, indicates that an ASME Code Section XI replacement of the #30 Roto-lok stud was conducted in Unit 2 during RFO 12 per the disposition of a design change package dated April 9, 2007. The design change package indicates that Stud #30 of Unit 2 had been rotated inadvertently during the detensioning process causing it to partially engage inside the stud insert, which is also called bushing, and this condition caused damage of all the lugs of the stud that were partially engaged. The design change package also indicates that the applicant decided that Stud #30 of Unit 2 would be replaced by a spare stud of the same kind from the warehouse, and, based on the evaluation performed on the stud insert, the applicant determined that the non-conforming condition of the stud insert is dispositioned as "Use-As-Is." The applicant's design change package further indicates that the damaged areas of the insert lug load-bearing surfaces are conservatively estimated to be 17 percent of the original load-bearing surfaces.

The staff noted that the RV flange threads engage with the outer-diameter threads of a stud insert and the inner-diameter lugs of the stud insert engage with the lugs of a mating stud. The staff also noted that UFSAR Section 5.3.1.7 describes the Roto-lok closure studs for the reactor head closure bolting. The descriptions in the UFSAR are summarized as follows. The Roto-lok closure stud uses a modified breech-lock design to secure the RV to the vessel head. The interrupted lugs of the Roto-lok stud cut in the lower and upper ends are generated by cutting separate parallel grooves in the studs. This modification prevents any contact with the engaging lugs when rotating the stud. An insert (which engages with the Roto-lok lugs of the stud) is used in the stud hole of the RV flange. The Roto-lok lugs are machined on the inside diameter of the insert, and the outside diameter (OD) is machined with standard threads. The insert is threaded into the vessel flange and locked in place by pins so that the interrupted portions of the lugs assume the same position on all bushings relative to the vessel centerline. The closure nut threads onto the stud at the RV head. The closure nut rests on a spherical washer, which sits on top of the reactor closure head.

During the audit, the staff also noted that the applicant's inservice inspection plan, Revision 4, dated September 29, 2008, specifies the inspection plan for the second interval that started from September 2000 and October 2000 for Units 1 and 2, respectively. Examination Category B-G-1, item B6.50, in the applicant's inspection plan indicates that alternative volumetric examination is specified as the inspection method for the closure bushings, which are also called stud inserts, instead of visual VT-1 examination specified in Table IWB-2500-1 of the 2004 edition of the ASME Code Section XI, Subsection IWB. The staff further noted that LRA Section B2.1.3 does not identify this alternative volumetric examination as an exception of the applicant's program. In its review, the staff found that the reduced load-bearing surfaces of the partially damaged (rolled) stud insert increase the stress level applied to the lugs of the stud insert such that loss of material due to wear and cracking because of SCC may be facilitated. In addition, the partially damaged stud insert may cause partial engagement and galling of the stud bolting and an adverse effect on the prevention of RV flange leakage. Therefore, the staff needed to confirm the technical basis of the continuous use of the partially damaged stud insert.

The staff also noted that visual VT-1 examination of closure bushings (also called stud inserts) is effective to detect, monitor, and manage loss of material due to wear or corrosion and to identify and monitor a change in the condition of the damaged stud insert, especially additional reduction in the load-bearing surfaces. Therefore, the staff needed to clarify whether the alternative volumetric examination of the closure bushings without VT-1 examination specified in ASME Code Section XI is adequate to manage the aging effects of the closure stud inserts. In addition, the staff needed to clarify why the alternative volumetric examination of the stud inserts is not an exception of the applicant's program and whether the applicant's operating experience supports the applicant's conclusion that the program is adequate to manage the aging effects.

By letter dated August 15, 2011, the staff issued RAI B2.1.3-2 requesting that the applicant describe whether a reactor head closure stud, stud insert, or RV flange surface has experienced corrosion or SCC due to RV flange leakage. It is also requested to justify why the alternative volumetric examination of the stud inserts is not an exception of the applicant's program. The staff further requested that, in view that the partially damaged stud insert has not been replaced, if existent, the applicant describe the results of inspection activities that it has conducted to monitor any change in the affected load-bearing areas of the partially damaged stud insert.

As discussed above, the staff found that the reduced load-bearing surfaces of the partially damaged (rolled) stud insert increase the stress level applied to the lugs of the stud insert such that loss of material due to wear and cracking because of SCC may be facilitated. The partially damaged stud insert may cause partial engagement and galling of the stud bolting and possible RV flange leakage. Therefore, the staff requested that the applicant justify why no replacement of the partially damaged stud insert is acceptable to manage loss of material and cracking. In view that VT-1 examination is effective to identify and monitor a reduction in the load-bearing surfaces, the applicant was also requested to justify why the alternative volumetric examination, without VT-1 examination specified in ASME Code Section XI, is adequate to manage loss of material and cracking. Furthermore, the staff requested that, based on the information and evaluation addressed above, if items—such as replacement of the damaged stud insert or augmented inspection, or both—are identified to be further implemented into the applicant's AMP, the applicant describe the items, commitments, and implementation schedules.

In its response dated September 15, 2011, the applicant stated that the reactor head closure studs have not been exposed to borated water from RV flange leakage and that during refueling when the refueling cavity is flooded, plugs are inserted into the stud holes in the RV flange to prevent borated water from coming in contact with the stud hole inserts. The applicant also indicated that there have been instances where the stud hole plugs have leaked, exposing the inserts to borated water, and when a stud hole plug is discovered to have leaked, the stud holes are cleaned. The applicant further indicated that periodic inspections of the stud hole inserts are performed as required by ASME Code Section XI, Table IWB-2500-1, to confirm their integrity. In addition, the applicant indicated that no corrosion has been found on the closure studs and inserts and that no SCC has been found on the closure studs, inserts, or RV flange.

Based on its review of the applicant's response regarding leakage, the staff finds that this portion of the response is acceptable because the applicant confirmed that the reactor head closure studs have not been exposed to borated water from RV flange leakage, and no SCC has been found on the closure bolting components, which indicates that these components have not been exposed to corrosive environments due to RV flange leakage, with no indication of SCC or corrosion. Additionally, the applicant confirmed that although there have been instances where the stud hole plugs have leaked during the RFOs, no corrosion has been found on the closure studs and inserts, which indicates that the stud plug hole leakage with a relatively short time period of environmental exposure has not caused a significant adverse effect on the aging of the reactor head closure bolting components.

In its response, the applicant provided the justification as to the use of the alternative volumetric examination without the VT-1 examination specified in ASME Code Section XI. The applicant indicated that the ultrasonic examination method was demonstrated in 1998 using a calibration block prepared from an actual spare stud hole insert, and the calibration block included notches at different depths on both the inside and outside surfaces to ensure that examination volume coverage and sensitivity were obtained. The applicant also indicated that the notches were representative of flaws that would be found inservice and that the demonstration confirmed that all inside and outside surface indications could be easily observed. The applicant further indicated that VT-1 examination of the bushings (also called stud inserts, flange inserts, or bushing inserts) will be performed in accordance with ASME Code Section XI, Table IWB-2500-1. In addition, the applicant indicated that Table IWB-2500-1 specifies VT-1 examination of RV pressure-retaining bushings, and for the current inspection interval, the NRC approved a relief request allowing ultrasonic examination of the bushings in lieu of the VT-1 examination. The applicant stated that the safety evaluation (SE) (ADAMS Accession No. ML110840076) of the approved relief request stated that the ultrasonic examination is equivalent to the VT-1 examination. The applicant also stated that inspections performed during the period of extended operation will be in accordance with the applicable Code edition. Furthermore, the applicant indicated that if any variances from the Code requirements are required, the variances will be submitted for approval through the relief request process.

Based on its review, the staff found that the VT-1 examination of the stud inserts, in accordance with the applicable Code edition, is adequate to detect and manage loss of material due to wear and cracking due to SCC of the stud inserts. The staff also noted that the applicant confirmed that the alternative volumetric examination was approved through the relief request process, and, if any variances from the Code requirements are required, the variances will be submitted for approval through the relief request process. The staff found this portion of the applicant's response acceptable because it ensures that adequate examinations will be identified and conducted on the reactor head closure bolting components, as approved by the NRC for the period of extended operation. However, the staff had concerns related to the subsequent inspection of the damaged stud insert and the continued use of the damaged stud insert as described in the following paragraphs. By letter dated November 15, 2011, the staff issued RAI B2.1.3-2a, requesting to obtain more information.

In its response, dated December 15, 2011, regarding the results of inspection activities conducted to monitor any additional change in the affected load-bearing areas of the partially damaged stud insert, the applicant indicated that an analysis was performed of the damaged stud hole insert, and the damaged areas of the insert lug's load-bearing surfaces were conservatively estimated to be 17 percent (which is 5.14 in^2) of the original areas of contact. The applicant also stated that the analysis assumed that no load would be transferred to any of the damaged portions of the insert lug's load-bearing surfaces and that, based upon this loss of load-bearing surface area, the bearing stress is still acceptable, and the stud hole insert is accepted for "Use-As-Is." In addition, the applicant stated that no tests other than those that are performed during normal stud installation are required. In its response regarding the continued use of the partially damaged (rolled) stud insert, the applicant further indicated that, as described above, an analysis of the damaged stud hole insert determined that even with a loss of 17 percent of the bearing surface area, the bearing stress is acceptable so that it is not necessary to replace the stud insert.

During its review of the applicant's response regarding its inspections of the damaged stud insert, the staff noted that the applicant did not provide information as to the results of its inspections conducted to monitor any additional adverse change in the affected load-bearing areas of the partially damaged stud insert. Therefore, the staff needed information to clarify whether the applicant performed inspections to monitor any additional adverse change in the load-bearing areas of the damaged stud insert. The staff also needed information to clarify whether subsequent inspection results, if any, indicate any additional reduction or flaw initiation in the load-bearing areas of the damaged stud insert beyond the partial damage (conservatively estimated 17 percent reduction in the load-bearing surfaces). The staff issued RAI B2.1.3-2a, asking the applicant to address these concerns, as described below in more detail.

During its review of the response regarding the continued use of the damaged stud insert, the staff noted that UFSAR Table 5.2-1, "Applicable Code Addenda for RCS Components," indicates that the Unit 2 RV head was constructed in accordance with the 1971 edition through summer 1973 addenda of ASME Code Section III. The staff also noted that NB-3232.2, NB-3233, and NB-3234 of the 1971 edition of ASME Code Section III specify the requirements for the maximum stress for bolts in normal, upset, and emergency conditions, respectively. These provisions of the ASME Code require that the maximum value of the service stress at the periphery of the bolt cross-section shall not exceed the three times the stress values of Table I-1.3 (i.e., not to exceed the three times design stress intensity values, S_m, for bolting materials for Code Class 1 components). The staff further noted that the applicant's response to RAI B2.1.3-2 does not provide information that clarifies that the partially damaged stud insert complies with the aforementioned requirements of the ASME Code Section III for the maximum service stress limit. In addition, the staff needed additional information to confirm that in faulted conditions, the maximum service stress of the damaged stud insert does not exceed the three times the stress values of Table I-1.3 in a consistent manner with the aforementioned ASME Code requirements.

By letter dated November 15, 2011, the staff issued RAI B2.1.3-2a requesting that the applicant do the following:

- clarify whether or not inspections have been conducted to monitor any additional adverse change in the load-bearing areas of the damaged stud insert since the partially damaged stud insert was placed in service after the applicant's engineering evaluation
- if subsequent inspections have been performed, provide the results of the inspections to confirm that neither additional reduction nor flaw initiation in the load-bearing areas has occurred beyond the original damage addressed above
- if the applicant has not conducted a subsequent inspection of the partially damaged stud insert, provide information regarding the schedule and examination methods for the subsequent inspection to be conducted
- describe its operating experience to clarify whether any other stud or stud insert has experienced damage similar to that of the partially rolled stud insert
- provide information to confirm whether the partially damaged stud insert complies with the aforementioned requirements of ASME Code Section III, NB-3232.2, NB-3233, and NB-3234, and describe the location of the maximum service stress
- provide information to clarify whether the maximum service stress of the damaged stud insert in faulted conditions does not exceed the three times the stress values of ASME Code Section III, Appendix I, Table I-1.3 in a consistent manner with the aforementioned ASME Code requirements and, alternatively, justify why the maximum stress of the damaged stud insert in the faulted conditions are acceptable

In its response dated December 15, 2011, the applicant stated that the required 10-year ASME Code Section XI inspections of all reactor closure head bolting components were performed during the Unit 2 fall 2008 RFO, and the stud inserts were ultrasonically inspected, as allowed by relief request RR-ENG-2-5 (approved by NRC correspondence dated June 17, 1999). The applicant also stated that the ultrasonic testing (UT) inspection did not identify any flaws in stud insert #30.

The applicant stated that it will enhance procedures to perform a remote VT-1 examination of stud insert #30, concurrent with the volumetric examination once every 10 years, to confirm no additional loss of bearing surface area (Enhancement 2). However, the staff identified a concern regarding the implementation schedule of this enhancement (prior to the period of the extended operation) because it could delay the first proposed visual examination for up to 10 years after entering the period of extended operation. Therefore, the staff issued RAI B2.1.3-2b, as described below. The staff's evaluation of the implementation schedule for the visual examination is also addressed in the evaluation section regarding Enhancement 2.

In its response dated December 15, 2011, the applicant also confirmed that no other stud or stud insert has experienced damage similar to that of stud insert #30, which is adequate clarification for the applicant's operating experience. The applicant further indicated that its response to the request regarding the compliance with the maximum stress requirements of ASME Code Section III would be provided in January 2012.

In its subsequent response dated January 18, 2012, the applicant stated that the Roto-lok Mechanism, which includes the stud insert, stud, and top closure head, is designed under all conditions to meet the requirements of the applicable sections of ASME Boiler and Pressure

Vessel Code, Section III, of the 1971 edition with addenda through the summer of 1973. The applicant also stated that because it is a stud insert, the maximum stud service stress and average stud service stress of Section NB-3230 are not directly applicable because the component is not a stud or bolt that is under tensile loading at all times. The applicant further stated that the stud insert loading is more complex, because the lugs are carrying a shear-stress component as well as a tensile stress component; therefore, the ASME Code Section III analysis methodology for components other than bolts is applied for the stud inserts.

In addition, the applicant stated that a comprehensive thermal-stress analysis for normal and upset conditions using a 3-D finite element model was performed and documented in the Addendum to the Combustion Engineering (CE) Stress Report, dated October 1986, and the maximum stress intensity range is 98.85 ksi with the ASME Code Section III allowable stress being 120 ksi. In its response regarding the maximum stress intensity location, the applicant indicated that the maximum range of stress intensity (primary plus secondary stress intensity), compared to the 3 S_m allowable, is on stud insert lug number 6. In addition, the applicant indicated that due to the nature of the bearing deformation damage, the stress analysis results are not considered to change because the critical cuts and the loading are not changed and the bearing stress on the non-deformed surfaces of the insert lugs was determined to be the limiting consideration.

In its response regarding the analysis for the faulted condition, the applicant stated that the maximum faulted condition stress for the Roto-lok stud system for the primary stress resulting from the maximum faulted condition transient (control rod ejection) is reported as 78.70 ksi in the CE Stress Report for South Texas Project Unit 1, dated October 1977, where it is compared to the 3.6 S_m value of 131.7 ksi. The applicant also stated that this limit for faulted conditions comes from ASME Code Section III, Appendix F.

In its review, the staff needed additional information to further clarify the applicant's response. By letter dated March 21, 2012, the staff issued RAI B2.1.3-2b requesting that the applicant provide the following information to further clarify its operating experience and response related to the AMP:

- justify the adequacy of the proposed inspection schedule since it appears that the schedule might not confirm the absence of an additional bearing surface reduction and degradation in the stud insert prior to the period of extended operation
- provide baseline information regarding the depth of the partially rolled areas and the characteristics of the transition regions of the partial rolling, which are adjacent to the undamaged surfaces of the lugs, in order to assess the degree of stress concentration due to damage
- provide correct references for Unit 2 instead of the reference for Unit 1 that the applicant provided for the stress analysis
- justify why the continued use of the damaged stud insert ensures that the stresses on the component for emergency conditions are bounded by the stress limits of ASME Code Section III
- provide additional information to justify why the partially rolled lugs do not invalidate the original stress analysis results and provide the maximum acceptable reduction in load-bearing surfaces of the stud insert lugs which complies with the stress limits in the ASME Code

In its response dated April 17, 2012, the applicant amended the proposed implementation schedule for Enhancement 2, such that the remote VT-1 examination of stud insert #30 will start in the current (third) inservice inspection interval, concurrent with the volumetric examination. The staff finds that the amended implementation schedule for the visual examination is adequate because the visual examination with the amended implementation schedule can confirm the absence of additional bearing surface reduction and aging degradation in the damaged stud insert prior to the period of extended operation in a timely manner.

The applicant also stated that the measured depth of the rolled indentation of stud insert #30 is approximately 0.005-0.010-inch-deep. All insert lugs have similar damage, and the rolled transition area is smooth to touch. A visual inspection was performed on the stud insert, and the inspector rubbed a rubber glove over the transition. The rubber glove was not damaged and it did not snag on the insert damage. Therefore, the applicant concluded that the transition was smooth and did not have upset metal in the area. In its review, the staff finds the applicant's response acceptable because of the applicant's confirmation that the degree of the depth of the rolled indentation is minimal with a smooth transition region, which provides reasonable assurance that the original analysis results for the primary and secondary stress intensities are not affected significantly by the amount of surface damage. The staff also noted that this additional information supports the applicant's previous response to RAI B2.1.3-2a, that the original stress analysis results are not considered to change because the critical cuts and the loading (for the primary and secondary stress intensities) are not changed.

In addition, the applicant provided the following references for the stress analysis on the Unit 2 stud inserts. In its review, the staff finds the applicant's response acceptable because the applicant provided relevant references for the Unit 2 stud inserts and confirmed that no change is necessary to the maximum stress intensity data provided in its previous response dated January 18, 2012.

- Unit 2 reference for the faulted condition: CE Report, CENC-1354, "Analytical Report for South Texas Project No. 2 Houston Lighting and Power Company," January 1979
- Unit 2 reference for the normal and upset conditions: Westinghouse Report MED-PCE-6279, "Addendum to the Combustion Engineering Final Stress Report for the South Texas Unit No. 2 Reactor Vessel," Section 11, June 24, 1988

Based on its review, the staff finds that the applicant's response regarding the stress analysis for the emergency conditions is acceptable because the applicant confirmed that the stress intensities for the emergency conditions are bounded by those for the design conditions, and the stress limits for emergency conditions are greater than those for the design conditions. As part of its response, the applicant also clarified that the maximum internal pressure (2,417 psig) resulting from all of the emergency condition transients is less than the design pressure of 2,485 psig; therefore, the primary stress intensities for the stud inserts resulting from the emergency conditions are less than those for the design conditions. The applicant further clarified that the limiting stud insert bearing stress occurs during the normal condition plant heatup transient, for which the stud tensile load exceeds any emergency condition stud tensile load.

In addition, the applicant stated that the maximum bolt tensile load applied to the lugs of a single stud insert is 2,593,000 lb following a plant heatup at 100 °F per hour, in accordance with CE Report CNEC-1354. Each of the total 21 lugs for stud insert #30 experienced conservatively a 17 percent reduction of its bearing area (the total bearing area for an undamaged lug is

1.44 in^2). Using the data, the applicant calculated the maximum bearing stress on each lug of the damaged stud inert as 103.33 ksi, which is derived from 2,593 kips/(7 x 3 x 1.195 in^2). In this calculation, 7 is the number of rows of lugs on each insert, 3 is the number of lugs per row, and 1.195 in^2 is the (remaining) undamaged bearing surface per lug. The applicant further compared the calculated stress to the tabulated yield strength of the stud insert material at a temperature of approximately 176.7 °C (350 °F), which is the stud insert temperature at the end of the heatup in accordance with Westinghouse Report MED-PCE-6279. The applicant confirmed that the calculated bearing stress (103.33 ksi) for the partially rolled stud inserts is less than the yield strength of the stud insert material at approximately 176.7 °C (350 °F), which is 118.5 ksi in accordance with the appendices of the 1986 edition of ASME Code Section III.

The applicant also indicated that for the bearing stress to reach the 118.5 ksi limit, the bearing area of each lug would have to be reduced to 1.042 in^2, which is 2,593 kips/(7 x 3 x 118.5 ksi). This reduction in the bearing surface would amount to a further 10.6 percent reduction (for a total combined reduction of 27.6 percent) with respect to the original bearing surface area of 1.44 in^2 for each lug. In this review, the staff finds the applicant's response regarding the bearing stress analysis acceptable because the applicant confirmed that the partial indentation does not increase the bearing stress level above the yield strength of the material for the stud insert and because a bearing stress level below the yield strength does not impose a significant adverse effect on the intended function of the stud insert. The staff finds that the applicant's analysis is also supported by the results of the applicant's UT examination performed in 2008, indicating that no flaw was identified in stud insert #30.

On the basis of its review, the staff finds that the applicant's responses regarding the AMP are acceptable, as described and evaluated above. In summary, the applicant's implementation of the visual examination of stud insert #30, concurrent with the volumetric examination, starting with the current (third) inservice inspection interval, is adequate to detect and manage the aging effects of the component, and the depth of the partial indentation on the lug bearing surfaces is minimal so there is no effect on the aging of the stud insert. The staff's concerns described in RAIs B2.1.3-2, B2.1.3-2a, and B2.1.3-2b (Parts 1-5) are resolved. The staff's evaluation of RAI B2.1.3-2b, Part 6, the fatigue time-limited aging analysis (TLAA) issue regarding the stud inserts, and the applicant's response, are described in SER Section 4.3.

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 evaluated and incorporated operating experience related to this program.

Based on its audit and review of the application, the staff finds that the applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. The staff reviewed this UFSAR supplement description of the program against the recommended description for this type of program, as described in SRP-LR, Revision 2, Table 3.0-1. The staff noted that in contrast with SRP-LR, Revision 2, Table 3.0-1, the applicant's UFSAR supplement description for the Reactor Head Closure Studs Program, which is described in LRA Section A1.3, does not include the statement that the applicant's program relies on recommendations, as delineated in NUREG-1339, "Resolution of Generic Safety Issue-29: Bolting Degradation or Failure in Nuclear Power Plants," and RG 1.65. In its review, the staff noted that NUREG-1339 and RG 1.65 indicate that molybdenum disulfide is a potential contributor to SCC. NUREG-1339 and RG 1.65 also include guidance for the yield strength levels of the bolting material resistant to SCC. The licensing basis for this program 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 September 22, 2011, the staff issued RAI B2.1.3-4, requesting that the applicant revise the applicant's UFSAR supplement description for the Reactor Head Closure Studs Program, consistent with the UFSAR supplement described in SRP-LR, Revision 2, Table 3.0-1, which includes the statement that the program relies on the recommendations delineated in NUREG-1339 and RG 1.65. The staff also requested that, if the applicant determined that a revision to the UFSAR supplement described in LRA Section A1.3 is not necessary, it justify why the omission of the information, regarding NUREG-1339 and RG 1.65, from the UFSAR supplement is acceptable to provide an adequate licensing basis for this program for the period of extended operation.

In its response dated October 25, 2011, the applicant stated that the program implements recommendations in NUREG-1339 and RG 1.65 to address reactor head stud bolting degradation except for yield strength of existing bolting materials. The staff's evaluation of the applicant's exception regarding the yield strength of existing bolting materials is described in the subsection of this evaluation for Exception 1. In its response, the applicant also revised LRA Section A1.3, consistent with its response, and confirmed that its program implements the recommendations delineated in NUREG-1339 and RG 1.65. The staff finds the applicant's response acceptable because the applicant revised the UFSAR supplement (LRA Section A1.3) to clarify that the program implements the recommendations delineated in NUREG-1339 and RG 1.65. Therefore, the staff finds that the UFSAR supplement for the Reactor Head Closure Studs Program, as supplemented by letters dated November 4, 2011, and April 17, 2012, is consistent with the corresponding program description in SRP-LR Table 3.0-1. The staff's concern described in B2.1.3-4 is resolved.

<u>Conclusion</u>. On the basis of its audit and review of the applicant's Reactor Head Closure Studs Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and determines that the AMP, with the exceptions, is adequate to manage the applicable aging effects. The staff also reviewed the enhancements and confirmed that their implementation through Commitment Nos. 38 and 42, as captured in amendments to the UFSAR supplement, prior to the period of extended operation and during the current (third) inservice inspection interval, respectively, will make the AMP adequate to manage the applicable aging effects. 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).

3.0.3.2.3 Boric Acid Corrosion

<u>Summary of Technical Information in the Application</u>. LRA Section B2.1.4 describes the existing Boric Acid Corrosion Program as consistent, with an enhancement, with GALL Report AMP XI.M10, "Boric Acid Corrosion." The LRA states that the program manages the effects of

loss of material and corrosion for mechanical, electrical, and structural components exposed to boric acid leakage. The LRA also states that the program includes provisions to identify leakage through visual inspections, inspect and examine for evidence of leakage, evaluate leakage, and initiate corrective actions. The LRA further states that long-term corrective actions to control boric acid leakage, impede boric acid leakage and attack, and prevent recurrence of leakage include the use of suitable materials, protective coatings and claddings, and increased RCS leakage monitoring.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.M10.

The staff also reviewed the portions of the "scope of program" program element associated with the enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this enhancement follows.

Enhancement. LRA Section B2.1.4 states an enhancement to the "scope of program" program element. In this enhancement, the applicant stated that the program will be enhanced to include electrical components and connectors adjacent to potential leakage sources and other materials (such as aluminum and copper alloy) that are susceptible to boric acid corrosion. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M10 and finds it acceptable because, when implemented, the LRA AMP will be consistent with the updated recommendations in the GALL Report, Revision 2, AMP XI.M10, which state that aluminum, copper alloys, and electrical components are appropriate materials and components that should be managed by this program.

Summary. Based on its audit and review of the applicant's Boric Acid Corrosion Program, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M10. In addition, the staff reviewed the enhancement associated with the "scope of program" program element and finds that, when implemented, it will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.4 summarizes operating experience related to the Boric Acid Corrosion Program. The LRA states that the applicant detected coolant leakage at a reactor coolant pump in 2004 that resulted in degradation of low-alloy steel housing bolts. The applicant attributed the borated water leakage to seal housing bolting relaxation. Of the 16 bolts contacted by the boric acid solution, 15 bolts failed the VT-1 inspection and were deemed ineligible for continued service. The applicant replaced the degraded bolts and leaking seal and created a preventive maintenance activity to periodically measure bolt elongation in the four RCP seal housings. The applicant found a recurrence of the leakage in September 2009, on the same RCP that had leaked earlier, and all seal housing bolts were again replaced. Further corrective actions were scheduled for October 2011, when this pump was to be disassembled for surface flatness checks.

The LRA states that, during a Boric Acid Corrosion Program walkdown in 2008, the applicant identified leakage from the RV inner O-ring leak-offline, emanating from a pipe-to-tube adapter to a flex hose. Moderate boron accumulation was observed, and a condition report was created to decontaminate, evaluate susceptible components, and make any necessary repairs. In addition, the applicant found four valves with packing leaks. The inspection found no corrosion or structural damage of susceptible materials and no leakage that affected the primary pressure boundary structural integrity.

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 evaluated and incorporated 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 staff lacked sufficient information to conclude that the applicant's program is effective at preventing instances of recurring leakage. By letter dated May 14, 2012, the staff issued RAI 3.2.2.1-1a, requesting that the applicant describe the results and any identified corrective actions from the seal flatness checks performed on the RCPs during the October 2011 RFO. (A second request in RAI 3.2.2.1-1a addressed the aging management of bolting surrounded by seal cap enclosures that contain borated water leakage and is documented in SER Section 3.1.2.1.4.).

In its response dated May 14, 2012, the applicant stated that a leakage monitoring program was established for the subject RCP until repairs could be completed during the fall 2011 outage; however, excessive leakage discovered following a November 2010 reactor trip prompted more immediate repairs. The applicant also stated that the apparent cause of the leakage was deformation and distortion of the seal housing due to pressure cycles and successive retightening of the joint, and the corrective action was to replace the seal housing and gasket. The staff finds the applicant's response acceptable because the additional information on the leakage monitoring and repair activities for the RCP provides additional confirmation that the Boric Acid Corrosion Program adequately addresses boric acid leaks such that component intended functions will be maintained during the period of extended operation. The staff's concern described in RAI 3.2.2.1-1a is resolved.

Based on its audit and review of the application, the staff finds that the applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A1.4 provides the UFSAR supplement for the Boric Acid Corrosion Program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1.

The staff also noted that the applicant committed (Commitment No. 2) to enhance the existing Boric Acid Corrosion Program prior to the period of extended operation to include electrical components and connectors adjacent to potential leakage sources and other materials (such as aluminum and copper alloy) that are susceptible to boric acid corrosion. By letter dated June 2, 2014, the applicant informed the NRC that activities associated with Commitment No. 2 were completed.

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Boric Acid Corrosion Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancement and confirmed that its implementation—through Commitment No. 2—prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. 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).

3.0.3.2.4 Flow-Accelerated Corrosion

Summary of Technical Information in the Application. LRA Section B2.1.6 describes the existing Flow-Accelerated Corrosion Program as consistent, with exceptions, with GALL Report AMP XI.M17, "Flow-Accelerated Corrosion." The LRA states that the AMP addresses carbon or low-alloy steel piping and piping system components, which contain high-energy fluids to manage, detect, measure, monitor, predict, and mitigate component wall thinning due to flow-accelerated corrosion.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.M17. The staff also reviewed the portions of the "scope of program," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," and "corrective actions" program elements associated with the exceptions to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of the exceptions follows.

Exception 1. LRA Section B2.1.6 states an exception to the "scope of program" and "detection of aging effects" program elements. In this exception, the applicant stated that the program will use the recommendations of EPRI guideline, NSAC-202L-R3, "Recommendations for an Effective Flow-Accelerated Corrosion Program," whereas the GALL Report, Revision 1, cites NSAC-202L-R2. The staff reviewed this exception against the corresponding program elements in GALL Report AMP XI.M17 and finds it acceptable because the GALL Report, Revision 2, states either version, R2 or R3, of the EPRI guideline is acceptable. Furthermore, by incorporating the guidance in NSAC-202L-R3, the applicant's program will be informed by updated industry experience documented through the CHECWORKS user's group and recent developments in detection, modeling, and mitigation technologies.

Exception 2. In response to RAI B2.1.6-1a, issued February 8, 2012, and discussed below, the applicant revised LRA Section B2.1.6 to include an exception to the "scope of program," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," and "corrective actions" program elements. In this exception, the applicant stated that the program will manage wall thinning due to mechanisms other than flow-accelerated corrosion. The response also stated that the aging effect of the additional mechanisms, wall thinning, is the same as for flow-accelerated corrosion, and the management of the additional mechanisms is the same as for lines that cannot be modeled in CHECWORKS. The staff reviewed this exception against the corresponding program elements in GALL Report AMP XI.M17 and finds it acceptable because the detection, monitoring, and acceptance criteria for the additional wall thinning mechanisms are the same as for flow-accelerated corrosion, and NSAC 202L includes guidance for inspection and selection of components that are not modeled.

Summary. Based on its audit of the applicant's Flow-Accelerated Corrosion Program, the staff finds that program elements one through six, for which the applicant claimed consistency with the GALL Report, are consistent with the corresponding program elements of GALL Report AMP XI.M17. The staff also reviewed the exceptions associated with the "scope of program," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," and "corrective actions" program elements and their justifications, and finds that the AMP, with the exceptions, is adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.6 summarizes operating experience related to the Flow-Accelerated Corrosion Program. As described in the LRA, a review of work orders from 1998 through October 2010 showed that there had been no flow-accelerated corrosion-related leaks or ruptures at STP for components within the scope of license renewal. The LRA describes instances in which program inspections identified minimum allowable wall thicknesses locations but were able to justify continued service and postpone replacements through rigorous stress analyses. The LRA also describes radiographic inspections of small-bore piping systems during recent refueling outages and states that the applicant conducted additional inspections, including adjacent areas upstream and downstream of thinned locations, based on the initial sample population. The LRA also states that replacement components used flow-accelerated corrosion-resistant materials, which included baseline wall thickness inspections for future reference.

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 evaluated and incorporated operating experience related to this program. During its review, the staff identified several condition reports associated with the flow-accelerated corrosion in the AFW system. However, LRA Section 3.4.2.1.6, "Auxiliary Feedwater System," did not include flow-accelerated corrosion as an AERM and did not include the Flow-Accelerated Corrosion Program in Table 3.4.2-6, "Auxiliary Feedwater System," as an applicable AMP. By letter dated September 22, 2011, the staff issued RAI 3.4.2.6-1 requesting that the applicant provide information regarding how flow-accelerated corrosion is being managed for piping components in the AFW system, in light of plant-specific condition reports.

In its response dated November 21, 2011, the applicant stated that components in the AFW system were initially identified as not susceptible to flow-accelerated corrosion because of infrequent operation; however, based on the identification of wear, certain components are now included in the program's System Susceptibility Evaluation. The applicant revised Table 3.4.2-6, "Auxiliary Feedwater System," by adding an AMR item for carbon steel piping exposed to secondary water, which is being managed for wall thinning by the Flow-Accelerated Corrosion Program and references LRA Table 3.4.1, item 3.4.1.29. The staff finds the applicant's response acceptable because the applicant added the components, which had initially not been identified as susceptible, to the scope of the Flow-Accelerated Corrosion Program due to operating experience. The staff's initial concern described in RAI 3.4.2.6-1 is resolved.

However, in the above response, the applicant stated that it identified additional systems within the scope of license renewal in which wall thinning due to erosion-corrosion mechanisms are being managed by the Flow-Accelerated Corrosion Program. Consequently, the applicant revised LRA Table 3.3.2-2, "Spent Fuel Pool Cooling and Cleanup System"; Table 3.3.2-9, "Chilled Water HVAC System"; Table 3.3.2-27, "Miscellaneous Systems"; and Table 3.4.2-4, "Demineralized Water (Make-up) System," to include AMR items for managing wall thinning using the Flow-Accelerated Corrosion Program. The staff noted that NSAC-202L states those degradation mechanisms associated with cavitation erosion and solid particle erosion, among others, are not part of a flow-accelerated corrosion program, and these mechanisms should be evaluated separately. In order to address this concern, by letter dated February 8, 2012, the staff issued RAI B2.1.6-1a requesting that the applicant provide additional details regarding inclusion of erosion and corrosion mechanisms in the scope of program for this AMP.

In its response dated February 27, 2012, the applicant stated that piping and components, which are susceptible to wall thinning due to mechanisms other than flow-accelerated corrosion, are managed the same as lines that are susceptible to flow-accelerated corrosion, although they cannot be modeled by CHECWORKS. The response also stated that inspections for these components are administratively controlled using a database developed by STP. In addition, the applicant revised LRA Appendix A1.6 and Appendix B2.1.6 to explicitly state that system components susceptible to erosion-corrosion, cavitation, flashing, and impingement damage are included in the "susceptible non-modeled" portion of the Flow-Accelerated Corrosion Program. The staff noted that the EPRI guidance document, NSAC-202L, includes consideration of "susceptible-not-modeled" components with respect to records, sample selection, and inspection scheduling. The staff finds the applicant's response acceptable because the detection, monitoring, and acceptance criteria for the additional wall thinning mechanisms are the same as for flow-accelerated corrosion, and NSAC 202L includes guidance for inspection and selection of components that are characterized as susceptible-not-modeled. In addition, the applicant characterized this change to the Flow-Accelerated Corrosion Program as an exception, which is discussed above. The staff's concerns described in RAI B2.1.6-1a are resolved.

Based on its audit and review of the application and review of the applicant's response to RAI 3.4.2.6-1, the staff finds that the applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

<u>UFSAR Supplement</u>. LRA Section A1.6 provides the UFSAR supplement for the Flow-Accelerated Corrosion Program. The applicant revised this section, in response to RAI 3.4.2.6-1 and RAI B2.1.6-1a, by explicitly stating that the program also manages wall thinning due to other causes, such as erosion-corrosion, in addition to flow-accelerated corrosion. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1 and includes additional information describing the inclusion of wall-thinning mechanisms other than flow-accelerated corrosion. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

<u>Conclusion</u>. On the basis of its audit and review of the applicant's Flow-Accelerated Corrosion Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and determines that the AMP, with the exceptions, is adequate to manage the applicable aging effects. 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).

3.0.3.2.5 Bolting Integrity

Summary of Technical Information in the Application. LRA Section B2.1.7, as amended by letters dated April 19, 2017, and May 2, 2017, describes the existing Bolting Integrity Program as consistent, with exceptions and enhancements, with GALL Report AMP XI.M18, “Bolting Integrity.” The LRA states that the AMP addresses pressure-retaining bolting and ASME component support bolting comprised of various materials exposed to plant indoor air, borated water leakage, treated borated water, and atmosphere and weather to manage the effects of cracking, loss of material, and loss of preload. The LRA also states that the AMP proposes to manage these aging effects through periodic visual and volumetric inspections, the use of preload control, proper selection of bolting material, the proper selection and use of lubricants or sealants, and inspection methods capable of detecting aging effects associated with closure bolting located in dry gas and compressed air systems.

Staff Evaluation. During its audit, the staff reviewed the applicant’s claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant’s program to the corresponding program elements of GALL Report AMP XI.M18. For the “detection of aging effects” program element, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The “detection of aging effects” program element in GALL Report AMP XI.M18 recommends that for high-strength structural bolting (actual measured yield strength greater than or equal to 150 ksi or 1,034 MPa) in sizes greater than 1-inch nominal diameter, volumetric examination comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, should be performed to detect cracking in addition to the VT-3 examination. However, during its audit, the staff found that the applicant’s Bolting Integrity Program states that volumetric examinations of high-strength structural bolts greater than 1-inch nominal diameter are not required because of the absence of a corrosive environment on these components. The program basis document states that the proper use of lubricants and sealants removes the components from the corrosive environment and concludes that cracking due to SCC is not an applicable aging effect because one of the three criteria necessary for SCC to occur is not present. By letter dated August 15, 2011, the staff issued RAI B2.1.7-2 requesting that the applicant provide additional information to demonstrate that all high-strength structural bolts have been completely removed from a corrosive environment and are not at risk of being exposed to a corrosive environment or update the program basis documents to include volumetric examinations of high-strength structural bolting in sizes greater than 1-inch nominal diameter.

In its response dated September 15, 2011, the applicant stated that its high-strength structural bolting is located in the reactor containment building and that the atmosphere in the containment building is plant indoor air, which is not considered corrosive. The applicant also stated lubricants containing molybdenum disulfide are not used in the reactor containment building. The applicant further stated that the high-strength structural bolts are visually inspected for corrosion, as required by the ASME Code Section XI, Subsection IWF, and that any indication of corrosion and the cause of the corrosive environment would be addressed by the CAP.

GALL Report AMP XI.M18 states that the recommendation to perform volumetric examinations of high-strength structural bolting may be waived with adequate plant-specific justification. The staff noted that a susceptible material, high stress, and a corrosive environment are all required in order for SCC to occur and that removal of any of the three criteria necessary for SCC to occur will remove the susceptibility of the component to SCC. The corrosive environment needed for SCC of high-strength materials to occur, as documented in EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants," and NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," March 1990, is an environment containing moisture or humidity. The staff also noted that typical reactor containment building environments can be warm and humid and that localized areas may experience high humidity and condensation. EPRI NP-5769 documents failures of high-strength structural bolts for SGs that were exposed to humidity. The staff also noted that degradation of sealants and lubricants increases with time and can allow for localized corrosive environments in the crevices of bolted connections. The staff further noted that the visual inspections performed by the ASME Code Section XI, Subsection IWF, are not intended to identify corrosion of the threaded surface or to identify SCC. It is unclear to the staff why the applicant's high-strength structural bolting is not susceptible to SCC. By letter dated December 6, 2011, the staff issued RAI B2.1.7-3 requesting that the applicant provide additional information to demonstrate that all in-scope high-strength structural bolts with greater than 1-inch nominal diameter have been completely removed from a localized corrosive environment and are not at risk of being exposed to a corrosive environment during the period of extended operation or update the program to include volumetric examinations comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1.

In its response dated January 5, 2012, the applicant revised its ASME Code Section XI, Subsection IWF and Structures Monitoring programs to include volumetric examinations—performed in accordance with ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1—of a representative sample of high-strength bolts. The applicant stated that the representative sample size is 20 percent with a maximum of 25 high-strength bolts greater than 1-inch diameter being inspected per unit. The applicant further stated that the representative sample will be selected from the bolts most susceptible to SCC based on exposure to moisture or humidity.

The staff finds the applicant's response acceptable for the following reasons:

- High-strength bolts with greater than 1-inch diameter will be volumetrically examined for SCC in accordance with ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, as recommended in the GALL Report.
- The sample size proposed by the applicant is consistent with other GALL Report AMPs' sampling programs.
- The representative sample of bolts selected for volumetric testing will be based on bolts in the most susceptible areas.
- The applicant does not use lubricants that contain molybdenum disulfide.
- The applicant does not have any plant-specific operating experience with SCC of high-strength bolts.

The staff's concerns described in RAIs B2.1.7-2 and B2.1.7-3 are resolved.

In its annual update letter dated October 22, 2014, the applicant revised LRA Table 3.3.2-4, "Essential Cooling Water and ECW Screen Wash System," to include new AMR items for copper alloy closure bolting submerged in water to be managed for loss of material and loss of preload. The applicant proposed to manage loss of material with the Open-Cycle Cooling Water System Program and loss of preload with the Bolting Integrity Program. The "detection of aging effects" program element of GALL Report AMP XI.M18 recommends periodic inspections of closure bolting for signs of leakage to ensure the detection of age-related degradation.

The staff noted that the corresponding GALL Report AMPs XI.M18 and XI.M20 do not include guidance for the inspection of submerged closure bolts. The staff also noted that the applicant's AMPs, described in LRA Sections B2.1.7 and B2.1.9, do not provide information regarding how degradation will be detected in a submerged environment that limits accessibility to perform visual inspections for detecting bolted joint leakage. The LRA AMPs also lack information regarding the frequency of inspections and a justification for such frequency for the submerged closure bolts. On February 23, 2016, the staff held a telephone conference call with the applicant to discuss the above concerns. During the call on February 23, 2016, as documented in a meeting summary dated March 7, 2016, the applicant clarified that the submerged closure bolts are the pump column bolts that interconnect the ECW pump column segments, which function as the pump casing. The applicant also stated that it would provide information on the docket describing how the submerged closure bolting will be inspected.

By letter dated March 10, 2016, the applicant provided additional information in response to the staff's concerns from the February 23, 2016, telephone conference call. The applicant stated that the ECW pump column bolts are managed for loss of preload through preventive actions given in its Bolting Integrity Program. These include proper torquing of bolts; checking for uniformity of gasket compression after assembly, application of an appropriate preload; and the selection of proper bolting materials and appropriate lubricants consistent with the guidelines in EPRI documents, manufacturers' recommendations, and plant procedures. With regard to detection of bolted joint leakage, the ECW pumps are subject to quarterly performance tests in which "pump parameters such as pressure and flow are trended to identify any potential leakage caused by loss of preload before the leakage could affect the ECW system from performing its intended functions." With regard to loss of material, the applicant stated that pump column bolts are subject to visual inspections through the Open-Cycle Cooling Water System Program during ECW pump refurbishments that are performed nominally every 10 years. The applicant further stated that there has been no documented operating experience related to loss of preload or loss of material for the pump column bolts during past refurbishments. The applicant revised the description of the Bolting Integrity Program in LRA Sections A1.7 and B2.1.7 to include the statements regarding the ECW pump column closure bolts for managing loss of preload, inspecting during ECW pump refurbishments, trending ECW pump performance tests, and managing loss of material through the Open-Cycle Cooling Water System Program.

The staff finds the applicant response acceptable because the combination of preventive actions, tests, and inspection activities described above provide the capability to detect and adequately manage the aging effects for the submerged closure bolts in the ECW pump before there is a loss of intended function. The staff's concerns described during the February 23, 2016, telephone conference call are resolved.

The staff also reviewed the portions of the "scope of program," "detection of aging effects," "parameters monitored or inspected," "monitoring and trending," and "corrective actions" program elements associated with the exceptions and enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these exceptions and enhancements follows.

Exception 1. LRA Section B2.1.7 states an exception to the "scope of program" program element. In this exception, the LRA states that EPRI TR-104213, "Bolted Joint Maintenance and Application Guide," is not directly referenced by this program. The LRA also states that the use of EPRI NP-5067, "Good Bolting Practices, A Reference Manual for Nuclear Power Plant Maintenance Personnel," in conjunction with EPRI NP-5769 and NUREG-1339 is equivalent. By letter dated August 15, 2011, the staff issued RAI B2.1.7-1 requesting that the applicant provide clarification on the use of EPRI NP-5067 as guidance for this program by providing an explanation of any contradictions between EPRI NP-5067 and the GALL Report AMP XI.M18 recommended guidance delineated in EPRI TR-104213, and its impact on this program.

In its response dated September 15, 2011, the applicant stated that LRA Section B2.1.7 and the program basis document would be revised to state that the Bolting Integrity Program conforms to the guidance in EPRI TR-104213 and to delete the exception to the "scope of program" program element. By letter dated November 4, 2011, the applicant revised LRA Section B2.1.7, as described in the letter dated September 15, 2011. In that revision, the applicant added an enhancement to the "scope of program" program element to enhance procedures to conform to the guidance in EPRI TR-104213. The applicant also revised the UFSAR supplement in LRA Section A1.7 to state that the program is consistent with EPRI TR-104213. The staff finds the applicant's response acceptable because the applicant revised its program to incorporate the guidance in EPRI TR-104213, which is consistent with the recommendations in the GALL Report; therefore, this exception is no longer applicable. The staff's concern described in RAI B2.1.7-1 is resolved.

Exception 2. LRA Section B2.1.7 states an exception to the "parameters monitored or inspected" program element. In this exception, the applicant stated that loss of preload is not a parameter of inspection for the Bolting Integrity Program. The applicant further clarified that indications of loss of preload are conducted during plant walkdowns through visual inspections for leakage, which would indicate a loss of preload. The staff reviewed this exception against the corresponding program element in GALL Report AMP XI.M18 and finds it acceptable for the following reasons:

- The applicant uses industry guidance for good bolting practices to achieve proper torque values for bolted connections.
- The loss of preload aging effect is still recognized as an applicable aging effect for bolted connections.
- The applicant performs periodic system walkdowns inspecting for visible leakage that would be indicative of loss of preload in the connection prior to a loss of intended function, which is consistent with GALL Report AMP XI.M18.

Exception 3. LRA Section B2.1.7 states an exception to the "monitoring and trending" program element. In this exception, the applicant stated that instead of following the GALL Report AMP XI.M18 recommended inspection intervals for leaking pressure-retaining components, the inspection frequency will be adjusted as necessary based on trending of inspection results to ensure there is no loss of intended function between inspection intervals. The staff noted that

Revision 2 of GALL Report AMP XI.M18 states that the periodic inspection of closure bolting for signs of leakage ensures that age-related degradation is detected and corrected before leakage becomes excessive. Revision 2 of GALL Report AMP XI.M18 also states that bolting connections reported to be leaking may be inspected in accordance with the corrective action process. The staff reviewed this exception against the corresponding program element in GALL Report AMP XI.M18 and finds it acceptable because the applicant will assess each event, record the occurrence, and perform periodic inspections, monitoring, and trending based upon the nature of the leakage through the use of its CAP, which is consistent with the recommendations in Revision 2 of GALL Report AMP XI.M18.

Enhancement 1. LRA Section B2.1.7 states an enhancement to the "corrective actions" program element. In this enhancement, the LRA states that procedures will be enhanced to evaluate loss of preload of the joint connection, including bolt stress, gasket stress, flange alignment, and operating condition, to determine the corrective actions consistent with EPRI TR-104213. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M18 and finds it acceptable because it will make the corrective action steps taken in regard to loss of preload consistent with the recommendations of GALL Report AMP XI.M18, which is consistent with the guidance provided in EPRI TR-104213.

Enhancement 2. LRA Section B2.1.7, as amended by letter dated November 4, 2011, states an enhancement to the "scope of program" program element. In this enhancement, the applicant stated that procedures will be enhanced to conform to the guidance contained in EPRI TR-104213. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M18 and finds the enhancement acceptable because Commitment No. 3, will make the program consistent with the recommendations in GALL Report AMP XI.M18, which is consistent with the guidance of EPRI TR-104213.

Enhancement 3. LRA Section B2.1.17, as amended by letters dated April 19, 2017, and May 2, 2017, states an enhancement to the "scope of program" and "detection of aging effects" program elements. In this enhancement, the LRA states that plant procedures will be revised to require a leak check of ASME closure bolting installed in dry gas and compressed air, and diesel exhaust systems. Techniques such as visual inspection for discoloration, monitoring and trending for pressure decay, leak fluid detection, or when the temperature of the system is higher than ambient conditions, thermography testing, will be conducted. The LRA also states that closure bolting installed in systems where the internal environment consists of atmospheric pressure will be checked for tightness prior to the period of extended operation and once every 6 years thereafter. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M18. The staff noted that GALL Report AMP XI.M18 recommends conducting leak inspections of closure bolting joints on a refueling outage interval. The staff also noted that checking for tightness results in both an inspection of the bolt head and directly verifies that potential loss of material, cracking, or loss of preload is not occurring. The staff finds the enhancement acceptable because: (a) the methods proposed in the enhancement are capable of detecting leakage in air-filled and gas-filled systems; (b) the Bolting Integrity Program conducts inspections on a refueling outage interval consistent with AMP XI.M18; and (c) for closure bolting installed in systems where the internal environment consists of atmospheric pressure, the test technique is more rigorous than a leak check to justify the longer interval between inspections.

Summary. Based on its audit and review of the applicant's responses to RAIs B2.1.7-1, B2.1.7-2, and B2.1.7-3; and review of the applicant's letters dated October 22, 2014, March 10, 2016, April 19, 2017, and May 2, 2017, the staff finds that the program elements for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M18. The staff also reviewed the exceptions associated with the "parameters monitored or inspected" and "monitoring and trending" program elements and their justifications, and finds that the AMP, with the exceptions, is adequate to manage the applicable aging effects. In addition, the staff reviewed the enhancements associated with the "scope of program," "detection of aging effects," and "corrective actions" program elements and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.7 summarizes operating experience related to the Bolting Integrity Program. In the LRA, the applicant states that the operating experience for this site is contained in condition reports. The applicant also states that 19 condition reports contain information applicable to this program. One instance of bolting degradation at this site involves condensation on the chilled water bolted connections, which caused surface corrosion of the bolts. In this instance, the areas were cleaned and either coated or insulated to prevent further corrosion caused by condensation. Other instances contained in the condition reports involve the degradation of bolted connections on fire protection piping. Each of these cases were discovered during walkdowns, and the affected components were replaced.

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 evaluated and incorporated 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 applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A1.7, as amended by letter dated April 19, 2017, provides the UFSAR supplement for the Bolting Integrity Program. The staff reviewed this UFSAR description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the applicant committed (Commitment No. 3) to enhance the bolting integrity program procedures to conform to the guidance contained in EPRI TR-104213; to evaluate loss of preload of the joint connection, including bolt stress, gasket stress, flange alignment, and operating condition to determine the corrective actions consistent with EPRI TR-104213 prior to the period of extended operation; and to conduct the inspections of closure bolting installed in dry gas or compressed air systems as described in Enhancement No. 3. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit; review of the applicant's Bolting Integrity Program; review of the applicant's responses to RAIs B2.1.7-1, B2.1.7-2, and B2.1.7-3; and review of the applicant's letters dated October 22, 2014, March 10, 2016, April 19, 2017, and May 2, 2017, the staff determines that the program elements for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report

AMP XI.M18. In addition, the staff reviewed the exceptions and its justifications and determines that the AMP, with the exceptions, is adequate to manage the applicable aging effects. Also, the staff reviewed the enhancements and confirmed that their implementation,—through Commitment No. 3 prior to the period of extended operation,—will make the AMP adequate to manage the applicable aging effects. 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 Open-Cycle Cooling Water System

Summary of Technical Information in the Application. LRA Section B2.1.9, as modified by letters dated March 5, 2012, March 29, 2012, July 5, 2012, August 21, 2012, and June 3, 2014, describes the existing Open-Cycle Cooling Water System Program as consistent, with an exception and enhancements, with GALL Report AMP XI.M20, “Open-Cycle Cooling Water System.” The LRA states that the AMP manages components exposed to raw water in the essential cooling water (ECW) and ECW screen wash systems for cracking, loss of material, and reduction of heat transfer. The LRA also states that the AMP manages these aging effects through surveillance techniques such as periodic visual inspections with thermal and hydraulic performance monitoring of heat exchangers. The LRA further states that the AMP includes preventive actions such as water chemistry controls, flushes, and physical or chemical cleaning (or both) of heat exchangers and the ECW pump suction bay to remove fouling and to reduce the potential sources of fouling. The LRA also states that loss of material due to selective leaching of aluminum bronze components in the ECW system is addressed in the plant-specific AMP, “Selective Leaching of Aluminum Bronze.” As a result of several RAIs associated with plant-specific operating experience, the applicant enhanced the program to include additional details for managing loss of coating integrity. Subsequently, the applicant modified the program to include the staff guidance for loss of coating integrity provided in LR-ISG-2013-01, “Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks.”

Staff Evaluation. During its audit, the staff reviewed the applicant’s claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant’s program to the corresponding program elements of GALL Report AMP XI.M20. For the “scope of program” program element, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The “scope of program” program element in GALL Report AMP XI.M20 states that the program addresses the aging effects of material loss and fouling; however, the applicant’s program description states that it also manages cracking. Although specified in the program description, the staff noted that the LRA did not include any AMR items with cracking as an AERM by this program. By letter dated August 15, 2011, the staff issued RAI B2.1.9-1 requesting that the applicant clarify if cracking is an AERM by the Open-Cycle Cooling Water System Program.

In its response dated September 15, 2011, the applicant stated that the Open-Cycle Cooling Water System Program manages loss of material and reduction of heat transfer, but cracking is not managed by this program. In its LRA amendment dated November 4, 2011, the applicant revised LRA Appendices A1.9 and B2.1.9 to delete cracking as an aging effect in the Open-Cycle Cooling Water System Program.

However, during its review of plant-specific operating experience, in LERs 499/2005-004 and 499/2010-001, the staff noted that cracking was apparently found in the heat-affected zone of the base metal near welds in the ECW aluminum bronze piping. Based on this information, it was unclear to the staff why there was no AMR item associated with cracking of copper-alloy piping and, if this aging effect needs to be managed, which AMP the applicant intends to use. In order to resolve this concern, by letter dated February 28, 2012, the staff issued RAI B2.1.9-1a requesting that the applicant provide the technical basis for not managing cracking as an aging effect in the aluminum bronze piping material.

In its response dated May 31, 2012, the applicant stated that the ECW piping cracks discovered in 2005 were located immediately downstream of the ECW return throttle valve for the component cooling water (CCW) heat exchanger, and the root cause analysis determined the cracks to be a secondary effect due to local flexing, which was the result of wall thinning due to cavitation erosion. The applicant also stated that the secondary effect of cracking did not require aging management because the primary cause of the failure, loss of material due to cavitation erosion, was already being managed by the Open-Cycle Cooling Water System Program. Regarding the ECW piping crack discovered in 2009, the applicant stated that the crack most likely resulted from a flaw in the heat-affected zone that propagated in the vent line close to the ECW return throttle valve in combination with cyclic stresses from vibration of that line. Following an evaluation of the extent of condition, the applicant removed the vent valves at the same locations from all of the ECW trains in both units. The applicant concluded that, since the cracking resulted from a fabrication flaw, it did not qualify as an aging effect needing management.

The staff finds the applicant's response acceptable because the root cause evaluations and subsequent corrective actions for these events demonstrate that the applicant adequately addressed cracking in its operating experience, and corrective actions have either addressed a fabrication issue that does not require aging management or that the aging management of the ongoing wall thinning will eliminate the local flexing and the need to manage cracking. The staff's concerns described in RAI B2.1.9-1 and RAI B2.1.9-1a are resolved.

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 "corrective actions" program elements associated with the exception and enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of the exception and enhancements follows.

Exception 1. LRA Section B2.1.9 states an exception to the "preventive actions," "parameters monitored or inspected," and "detection of aging effects" program elements. In this exception, the applicant stated that an exception is taken to flushing and inspecting the interior of the ECW cross-tie dead legs. Instead, the LRA states the external surfaces of the cross-tie lines are included in the 6-month dealloying external visual inspections through the Selective Leaching of Aluminum Bronze Program. The LRA also states that the cross-tie valves and piping are included in the ECW system inservice pressure test, which includes VT-2 inspection of these components. The staff reviewed this exception against the corresponding program elements in GALL Report AMP XI.M20 and finds it acceptable because the applicant's visual inspections of these valves and piping during ECW inservice pressure testing and as part of the Selective Leaching of Aluminum Bronze Program have the ability to detect leakage from the associated components and will adequately manage aging prior to a possible loss of intended function.

Enhancement 1. LRA Section B2.1.9 states an enhancement to the "parameters monitored or inspected," and "detection of aging effects" program elements. In this enhancement, the applicant stated that procedures will be enhanced to include visual inspection of the ECW strainer inlet area and the interior surfaces of the adjacent upstream and downstream piping. The LRA states that these inspections will provide visual evidence of loss of material and fouling in the ECW system and serve as an indicator of the condition of the interior of ECW system piping components otherwise inaccessible for visual inspection. Procedures will also be enhanced to include the acceptance criteria for this visual inspection. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M20 and finds it acceptable because, when implemented, it will provide the visual inspections recommended in the GALL Report to determine whether corrosion, erosion, or biofouling are occurring at a critical point in the ECW system where raw water is drawn in from the ECW pond through the ECW strainer inlets.

Enhancement 2. In letter dated March 5, 2012, the applicant added an enhancement to the "scope of program," "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements. In this enhancement, the applicant stated that procedures will be enhanced to include a minimum of 25 ECW piping locations to be measured for wall thickness in areas considered to have the highest corrosion rates. The wall thickness measurements were added in response to RAI 4.7.3-2, dated March 5, 2012, which was associated with LRA Section 4.7.3, "TLAA for the Corrosion Effects in the ECW System." The TLAA addressed the applicant's June 23, 1992, revised response to Generic Letter (GL) 89-13, "Service Water System Problems Affecting Safety-Related Equipment," dated April 4, 1990, which contained a corrosion rate analysis to justify that the 40-mil corrosion allowance for ECW piping would not be exceeded during the 40-year plant life. The applicant originally dispositioned the TLAA by managing loss of material with the Open-Cycle Cooling Water System Program; however, the staff did not have sufficient information to conclude that the visual inspections in this program would be capable of ensuring that the corrosion allowance would not be exceeded in the period of extended operation. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M20 and finds it acceptable because, when it is implemented, the wall thickness measurements will directly monitor thickness reductions as the minimum design thickness is approached; thus, the measurements are capable of detecting degradation prior to loss of intended function. The staff's evaluation of information provided in response to RAI 4.7.3-2 is provided in SER Section 4.7.3.

Enhancement 3. In letter dated March 29, 2012, the applicant added an enhancement to the "corrective actions" program element. In this enhancement, the applicant stated that procedures will be enhanced to require that loss of material and protective coating failures be documented in the CAP and that an engineering evaluation of the condition be performed. The staff noted that this enhancement was in response to issues associated with monitoring activities for cavitation erosion, discussed below in RAI B2.1.9-2a, dated February 27, 2012.

The staff notes that in response to RAIs 3.0.3-2 and 3.0.3-2a, the applicant provided additional details for the "corrective actions" program element. The staff's evaluation of the AMP changes associated with managing loss of coating integrity, which includes the applicant's responses to the above RAIs, is in SER Section 3.0.3.3.5.

Enhancement 4. In its response to RAI B2.1.9-4a by letter dated July 5, 2012, the applicant added an enhancement to the "scope of program," "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements. In this enhancement, the applicant stated (Commitment No. 4) that procedures will be enhanced to require an engineering evaluation after each inspection of the aluminum-bronze piping inside the slip-on flange downstream of the CCW heat exchanger. The applicant also stated that the evaluation will calculate the projected wear over the next inspection interval, including a margin of 4 years of wear at the actual current yearly wear rate, and that corrective actions will be taken if the wall is projected to be reduced to less than minimum wall thickness. The staff reviewed this enhancement and finds it acceptable because, when it is implemented, the applicant will project wear over the next inspection interval and include an additional margin of 4 years of wear, which provides reasonable assurance that any uncertainties associated with the durability of the coatings—which are applied to protect the underlying piping—have been taken into consideration. The discussion below, regarding RAIs B2.1.9-4 and B2.1.9-4a, provides additional information on this issue.

Enhancement 5. In response to RAI B2.1.9-3c (discussed in the Operating Experience section below), dated August 21, 2012, the applicant added an enhancement to the "parameters monitored or inspected" and "detection of aging effects" program elements. In its response dated June 3, 2014, to RAI 3.0.3-2, the applicant subsequently modified this enhancement to also include the "monitoring and trending" and "acceptance criteria" program elements. The staff's evaluation of AMP changes associated with managing loss of coating integrity is in SER Section 3.0.3.3.5.

Summary. Based on its audit and review of the applicant's responses to RAI B2.1.9-1, RAI B2.1.9-1a, RAI B2.1.9-2a, RAI B2.1.9-3c, RAI B2.1.9-4a, RAI 3.0.3-2, RAI 3.0.3-2a, and RAI 4.7.3-2, the staff finds that the program elements for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M20. The staff also reviewed the exception associated with the "preventive actions," "parameters monitored or inspected," and "detection of aging effects" program elements, and its justification, and finds that the AMP, with the exception, is adequate to manage the applicable aging effects. In addition, the staff reviewed enhancements associated with the "scope of program," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," and "corrective actions" program elements and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.9 summarizes operating experience related to the Open-Cycle Cooling Water System Program. The applicant stated that plant-specific operating experience identified macrofouling, general corrosion, erosion corrosion, and through-wall dealloying in aluminum bronze components. The applicant also stated that its evaluation of through-wall dealloying determined this degradation is slow and that catastrophic failure is not a consideration. The applicant further stated that leakage can be detected before flaws reach a limiting size that would affect the intended functions of the systems and that a long-range improvement plan had been developed. The staff notes that the applicant addressed loss of material due to through-wall dealloying of aluminum bronze components in the ECW system in the plant-specific AMP, "Selective Leaching of Aluminum Bronze," which is discussed in SER Section 3.0.3.3.3.

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 evaluated and incorporated 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 RAIs, as discussed below.

As part of its AMP audit walkdown of the ECW system, the staff noted significant cavitation downstream of a throttle valve on the return line for the CCW heat exchanger. This issue was described in LER 499/2005-004, "Inoperability of Essential Cooling Water." However, in lieu of correcting the cavitation issue, the applicant instead chosen to manage the consequent loss of material. In addition, during its independent search of plant operating experience information, the staff identified several additional examples of cavitation issues in the ECW system that have been noted to cause erosion-corrosion. However, these issues were not discussed in the program's Operating Experience section of the LRA. By letter dated September 22, 2011, the staff issued RAI B2.1.9-2, requesting that the applicant clarify how the Open-Cycle Cooling Water System AMP manages the loss of material due to the cavitation-erosion issues found in the ECW system. Additionally, the RAI requested the applicant to provide details of the "Erosion Monitoring Program" that resulted from CR 06-3132 and to describe the extent of condition reviews it had performed to evaluate whether other systems' components had comparable issues.

In its response dated November 21, 2011, the applicant stated that the Open-Cycle Cooling Water System AMP manages erosion-corrosion, and the general system inspections of the ECW system include inspections for erosion and corrosion. The applicant also stated that, in response to CR 06-3132, for erosion downstream of a leaking valve, it had developed an erosion monitoring plan to identify and perform thickness measurements on the components most susceptible to erosion in the ECW system. The applicant further stated that its extent of condition review for CR 06-3132 identified the corresponding valves in the other ECW train and all the other throttle valves in the ECW system as likely locations for erosion to occur. In addition, the applicant stated that it selected additional locations for monitoring based on guidance from EPRI 1010059, "Service Water Piping Guideline." The response also stated that wall thickness is monitored using UT and radiography, and that the erosion monitoring plan includes a database that tracks components, thickness measurements, and remaining life and includes the schedule for re-inspections and for new locations to be inspected. Regarding the extent of condition reviews, the response stated that locations in other systems were not evaluated because "the unique material/environment combination of the ECW system is not found in other systems and erosion has not been found in other systems."

The staff finds certain aspects of the applicant's response acceptable, in that, for "parameters monitored/inspected" and "detection of aging effects," the applicant's program includes wall thickness measurements using techniques capable of identifying loss of material in components. In addition, the staff finds that the UT measurements are sufficiently accurate to determine the need for corrective actions or to plan future re-inspections.

However, the staff finds other aspects of the applicant's response unacceptable, in that it did not fully describe the enhancement made to the Open-Cycle Cooling Water System AMP and did not address the changes to the individual elements of the program. In addition, it was unclear to the staff why the applicant stated that erosion had not been found in other systems when its response to RAI 3.4.2.6-1 stated that it had identified six systems subject to wall thinning due to erosion-corrosion. In order to resolve this concern, by letter dated February 27, 2012, the staff issued RAI B2.1.9-2a requesting that the applicant clarify the enhancement, including all of the affected program elements, and clarify the discrepancy between its previous responses.

In its response dated March 29, 2012, the applicant stated that the Open-Cycle Cooling Water System Program manages the flanged connections at the ECW valves for cavitation-erosion, and that the LRA Basis Document, LRA Appendix B2.1.9 and LRA Table A4-1 were revised to address cavitation-erosion at these locations. The response also states that the program basis document's "parameters monitored or inspected" and "detection of aging effects" program elements were revised to clarify that inspection of the aluminum bronze piping and slip-on flanges downstream of the ECW throttle valves are being performed every 5 years. The response further states that an enhancement to the "corrective actions" program element was made to require a condition report and engineering evaluation whenever inspections identify loss of material in piping or protective coating failures. The staff finds this aspect of the applicant's response acceptable because the applicant described the enhancement to the affected program elements which will ensure that loss of material and fouling will be evaluated such that the intended functions will be maintained during the period of extended operation.

With respect to the discrepancy between its previous responses regarding the identification of erosion in other systems, the applicant stated that terms such as "erosion" and "erosion corrosion" describe loss of material in piping and piping components due to various mechanisms, such as flow erosion, cavitation erosion, and impingement, among others. The applicant also stated that the response to RAI B2.1.9-2, in focusing on the cavitation-erosion mechanism affecting ECW piping downstream of the ECW outlet throttle valves for the CCW heat exchangers, had inadvertently stated that erosion had not been found in other systems. The applicant also clarified that various types of erosion had been found in other systems and, as noted in its response to RAI B2.1.6-1a, the components subject to erosion in these other systems are managed by the Flow-Accelerated Corrosion program as "susceptible-not-modeled" components. The staff finds this response acceptable because the discrepancy between responses to RAI B2.1.9-2 and RAI 3.4.2.6-1 has been resolved, and the components affected by erosion-corrosion are being managed by the applicant. The staff's concerns described in RAIs B2.1.9-2 and B2.1.9-2a are resolved.

Also, during its independent search of plant operating experience information, the staff identified several condition reports that appeared to identify flow blockage due to foreign material resulting from debris because of protective coating failures. The LRA did not describe the protective coatings used in the ECW system and did not discuss changes to the program as a result of the apparent flow blockage. By letter dated September 22, 2011, the staff issued RAI B2.1.9-3 requesting that the applicant provide the basis showing that the AMP's surveillance and control techniques will adequately manage fouling of in-scope heat exchangers caused by protective coating failures.

In its response dated November 21, 2011, the applicant stated that certain components in the ECW system are coated to protect the underlying metal surfaces from being exposed to the erosive or corrosive effects of the open-cycle cooling water and described the types of coatings used and components that are coated. The portion of the applicant's response related to managing loss of coating integrity for these components was made moot by the applicant's changes to its Open-Cycle Cooling Water System Program to address loss of coating integrity as a result of new staff guidance in LR-ISG-2013-01. The staff's evaluation of the applicant's changes is documented in SER Section 3.0.3.3.5. The response also discusses several condition reports including a recent event in 2011 (CR 11-1218) in which pieces of coating were found in some of the tubes in the reactor containment building chiller.

The staff found certain aspects of the applicant's response unacceptable because coating degradation has apparently resulted in material of sufficient size to block heat exchanger tubes, and the lack of adverse effect appeared to be related to the amount of coating debris in contrast to the inability of the coating debris to affect intended functions. In order to resolve this concern, by letter dated February 27, 2012, the staff issued RAI B2.1.9-3a, asking the applicant to provide corrective actions that have either resulted in enhancements to this AMP or in changes to the coatings used in the ECW system to support the conclusion that the effects of aging will be adequately managed to maintain intended function of downstream components.

In its response dated March 28, 2012, the applicant stated that its search of condition reports did not find incidents in which coating failures resulted in cooling water heat exchanger tube blockage and that there has been no plugging of tubes by Belzona coatings. The response concluded that, based on operating history, the ability of the ECW system to perform its intended functions is not affected by erosion of Belzona coatings and that the effects of aging are being adequately managed by the Open-Cycle Cooling Water System Program.

In its review of the applicant's response, the staff determined that the previously cited condition report (CR 11-1218) was not associated with a component within the scope of license renewal, and the component was not within the ECW system. In addition, the response further discussed CR 07-16847, and, although coating debris was found in the heat exchanger, the tube blockage was not related to the coating degradation. Although the applicant clarified that there has been no blockage or plugging of in-scope heat exchanger tubes by Belzona coatings, the staff noted that erosion of Belzona coatings has resulted in release of coating material, which could result in fouling of downstream in-scope components. In addition, recent industry operating experience indicates that some internal coatings are considered limited-life applications, with a service life less than 20 years.

In its response dated August 21, 2012, to RAI B2.1.9-3c, the applicant provided a table identifying 30 items where coating failures may adversely affect the safety function of downstream components, and included the coating type, the service life, and the date of the initial coating installation for each item. By letter dated November 19, 2012, the staff issued RAI B2.1.9-3d requesting the applicant to address additional issues related to managing loss of coating integrity and the associated issues were identified as OI 3.0.3.2.6-2 in the 2013 SER with Open Items.

In its response to RAI B2.1.9-3d dated February 27, 2014, the applicant provided additional clarification relating to the plant-specific operating experience for previously completed coating inspections. Following receipt of the applicant's RAI response, the staff concluded that, based on recent industry operating experience and questions raised during the staff's review of other LRAs, several AMPs and AMR items in the LRA may not adequately account for loss of coating integrity for Service Level III (augmented) coatings. Therefore, by letter dated March 6, 2014, the staff's issued RAI 3.0.3-2, "Loss of Coating Integrity for Service Level III Coatings," to obtain additional information. The staff's evaluation of the applicant's responses and subsequent changes to its Open-Cycle Cooling Water System Program is documented in SER Section 3.0.3.3.5. The open item, OI 3.0.3.2.6-2 is closed based on the staff conclusions that the changes to the Open-Cycle Cooling Water System Program are consistent with the staff's guidance provided in LR-ISG-2013-01.

In addition, during its independent search of plant operating experience information, the staff identified a condition report indicating that protective coatings, which were applied to mitigate cavitation and erosion damage in piping and valve bodies near the ECW return throttle valves, were no longer present after 2 years and that pipe metal wall loss was found. The staff noted that the program basis document for this AMP stated that these coatings were inspected during preventive maintenance activities approximately every 4 years. In addition, the AMP basis document stated that although these coatings protect the underlying metal surfaces from being exposed to the raw water environment, the coatings are not credited in aging management to protect metal surfaces. By letter dated September 22, 2011, the staff issued RAI B2.1.9-4 requesting that the applicant provide the technical basis used to justify the preventive maintenance inspection frequency of the protective coatings of approximately 4 years and to provide the technical basis to show that the protective coatings were not being credited for those areas exposed to cavitation erosion.

In its response dated November 21, 2011, the applicant stated that it is acceptable for the coatings to erode away between inspections because the piping inspection frequencies, which are based on maintenance histories, ensure that the piping is repaired or replaced before it reaches the minimum allowable wall thickness. The response also stated that the wear rate is calculated from the current wear measurement and the previous wear measurement, which is then used with conservatisms to calculate the lifetime of the component.

The staff finds certain aspects of the applicant’s response unacceptable, in that calculating a wear rate by using the previous wall thickness measurement and the current wall thickness measurement inherently credits the coating’s protection of the metal surface, which is inconsistent with the applicant’s position regarding coatings. In order to resolve this concern, by letter dated February 28, 2012, the staff issued RAI B2.1.9-4a, asking the applicant to provide information relative to the conservatisms used in the calculation that establishes the lifetime of the component.

In its response dated March 29, 2012, the applicant stated that the program inspects for erosion of the aluminum bronze piping and that the coatings used to extend the life of the piping are replaced, as needed, during the 5-year preventive maintenance inspections. The response also stated that an engineering evaluation is performed to determine the extent and depth of the erosion found during these inspections and to determine whether the affected areas are acceptable until the following 5-year inspection. The staff noted that the applicant’s response did not include information relative to the conservatisms used in the calculations that establish the lifetime of the components. In order to address this concern, the staff issued RAI B2.1.9-4b by letter dated May 14, 2012, requesting the applicant to provide information related to its service life calculations to confirm that the methodology provides adequate conservatism to account for the uncertainties related to coating’s protection of pipe wall.

In its response dated July 5, 2012, the applicant stated that the coating is credited in the sense that the current inspection interval assumes that the metal surface coating will be consistently reapplied, as required, following each inspection, in accordance with vendor instructions. In addition, the applicant provided detailed information regarding its past inspections and proposed criteria for determining the need to repair or replace the associated piping. The applicant revised LRA Sections A1.9 and B2.1.9 to state that the piping will be repaired or replaced in accordance with the CAP if the projected wear over the next inspection interval, including a margin of 4 years of wear at the current yearly wear rate, results in a thickness less than the minimum wall thickness. The applicant also provided an additional enhancement to the program and a corresponding change to Commitment No. 4 to reflect this approach.

The staff finds the response acceptable because the applicant enhanced its evaluation methodology by including an additional margin of 4 years of wear at the calculated yearly wear rate when determining the need to repair or replace the associated piping. The staff notes that inclusion of this additional margin accounts for the applicant’s inherent assumption of crediting the metal surface coating protection and provides an appropriate methodology to project remaining piping life and to repair or replace it before wall thickness falls below the minimum. The staff’s concerns described in RAI B2.1.9-4, RAI B2.1.9-4a, and RAI B2.1.9-4b are resolved.

Based on its audit and review of the application and review of the applicant's responses to RAI B2.1.9-2, RAI B2.1.9-2a, RAI B2.1.9-3, RAI B2.1.9-3a, RAI B2.1.9-3c, RAI B2.1.9-4, RAI B2.1.9-4a, and RAI B2.1.9-4b, the staff finds that the applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A1.9 provides the UFSAR supplement for the Open-Cycle Cooling 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 3.0-1 and noted that the LRA also specifies cracking as an aging effect being managed by the Open-Cycle Cooling Water System Program. As noted previously, there are no AMR items in the LRA that identify cracking as an AERM for the Open-Cycle Cooling Water System Program; therefore, the licensing basis specified in the UFSAR supplement for this program may not accurately reflect the scope of the program implemented through AMRs. By letter dated August 15, 2011, the staff issued RAI B2.1.9-1 requesting that the applicant clarify if cracking is an AERM by the Open-Cycle Cooling Water System Program.

In its response dated September 15, 2011, the applicant stated that the Open-Cycle Cooling Water System Program manages loss of material and reduction of heat transfer, but cracking is not managed by this program. In its LRA amendment dated November 4, 2011, the applicant revised LRA Appendix A1.9 to delete cracking as an aging effect in the Open-Cycle Cooling System Water Program.

The staff also noted that the applicant committed (Commitment No. 4) to enhance the Open-Cycle Cooling Water System Program procedures to incorporate the following prior to the period of extended operation:

- include visual inspection of the strainer inlet area and interior surfaces of the adjacent upstream and downstream piping
- include acceptance criteria for this visual inspection
- require wall thickness measurements of a minimum of 25 ECW piping locations
- require an engineering evaluation after each inspection of the piping downstream of the CCW heat exchanger that will project future wear, including a margin of 4 years of wear at the actual yearly rate
- require loss of material in piping and coating failures to be documented in the CAP
- require that an engineering evaluation be performed when loss of material or coating failure is identified

The staff finds that the information in the UFSAR supplement, as amended by letters dated November 4, 2011, March 5, 2012, July 5, 2012, August 21, 2012, and November 12, 2015 (see SER Section 3.0.3.3.5), is an adequate summary description of the program. Therefore, the staff's concern in RAI B2.1.9-1 is resolved.

Conclusion. On the basis of its audit and review of the applicant's Open-Cycle Cooling Water System Program, the staff determines that the program elements for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M20. In addition, the staff reviewed the exception and its justification and determines that the AMP, with the exception, is adequate to manage the applicable aging effects. The staff also reviewed the enhancements and confirmed that their implementation—through Commitment No. 4 prior to the period of extended operation—will make the AMP adequate to manage the applicable aging effects. 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 Closed-Cycle Cooling Water System

Summary of Technical Information in the Application. LRA Section B2.1.10 describes the existing Closed-Cycle Cooling Water System Program as consistent, with exceptions and enhancements, with GALL Report AMP XI.M21, “Closed-Cycle Cooling Water System.” The LRA states that the AMP manages closed-cycle cooling water (CCCW) system components exposed to CCCW for loss of material, cracking, and reduction of heat transfer. The LRA also states that the AMP proposes to manage these aging effects through preventive measures to minimize corrosion, including maintenance of corrosion inhibitor and biocide concentrations and periodic system and component testing and inspection. Preventive measures include the monitoring and control of chemistry parameters following the guidance of EPRI TR-107396, Revision 1 (issued as EPRI TR-1007820).

Staff Evaluation. During its audit, the staff reviewed the applicant’s claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant’s program to the corresponding program elements of the staff’s updated position in GALL Report AMP XI.M21A, “Closed Treated Water Systems,” in Revision 2 of the GALL Report.

The staff also reviewed the portions of the “preventive actions,” “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” “acceptance criteria,” and “corrective actions” program elements associated with exceptions and an enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff’s evaluation of these exceptions and enhancements follows.

Exception 1. LRA Section B2.1.10 states an exception to the “preventive actions,” “parameters monitored or inspected,” and “acceptance criteria” program elements. In this exception, the applicant stated that EPRI TR-1007820 establishes chloride and fluoride as control parameters, which should be monitored monthly. As an exception, the applicant monitors chloride and fluoride as diagnostic parameters in the HVAC chilled water systems with an alert value of 5 ppm, which is more restrictive than the EPRI control parameter of less than or equal to 10 ppm. The applicant also stated that the makeup water to the HVAC chilled water systems is demineralized, and there are no known pathways for chloride and fluoride to enter the system. The staff reviewed this exception against the corresponding program elements in GALL Report AMP XI.M21A and finds it acceptable because the monitoring of chloride and fluoride as diagnostic parameters with a 5 ppm alert value is capable of ensuring that the levels of these contaminants in the HVAC chilled water systems are kept sufficiently low to manage corrosion and cracking.

Exception 2. LRA Section B2.1.10 states an exception to the “parameters monitored or inspected,” “detection of aging effects,” and “monitoring and trending” program elements. In this exception, the applicant stated that performance and functional testing of heat exchangers served by the in-scope CCCW systems is not performed since this testing is not included in the guidance found in EPRI TR-1007820. The staff reviewed this exception against the corresponding program elements in GALL Report AMP XI.M21A and finds it acceptable because the removal of performance testing is consistent with the updated staff position in GALL Report AMP XI.M21A, in which water treatment, water chemical testing, and inspections, rather than performance testing, are recommended to effectively manage aging.

Exception 3. LRA Section B2.1.10 states an exception to the "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements. In this exception, the applicant stated that the program uses the guidance found in EPRI TR-107396, Revision 1 (issued as EPRI TR-1007820). The staff reviewed this exception against the corresponding program elements in GALL Report AMP XI.M21A and finds it acceptable because, while the GALL Report, Revision 1, references TR-107396, Revision 0, the current staff position in the GALL Report, Revision 2, references the updated guidance found in EPRI TR-1007820.

Enhancement 1. LRA Section B2.1.10 states an enhancement to the "detection of aging effects," "monitoring and trending," "acceptance criteria," and "corrective actions" program elements. In this enhancement, the applicant stated that procedures will be enhanced to include visual inspection of the interior of the piping that is attached to the excess letdown heat exchanger CCW return second check valves. The applicant also stated that this periodic internal inspection is intended to detect loss of material and fouling and serve as a leading indicator of the condition of interior piping components. The applicant further stated that procedures will include acceptance criteria for this inspection. However, the staff noted that the LRA does not specify opportunistic inspections when systems are opened for maintenance or a maximum 10-year inspection interval, as recommended in GALL Report AMP XI.M21A. By letter dated August 15, 2011, the staff issued RAI B2.1.10-1, requesting that the applicant provide technical justification for not including opportunistic inspections in the CCCW System Program. The staff also requested that the applicant state how often a representative sample of inspections will be conducted during the period of extended operation and, if the inspection interval exceeds 10 years, provide technical justification for why the frequency is adequate to manage the aging effects of reduction of heat transfer, loss of material, and cracking. The staff further requested that the applicant confirm whether the proposed inspection location is representative of the components most likely to corrode or crack for all the material-aging effect combinations managed by the CCCW System Program (e.g., cracking of stainless steel, reduction of heat transfer of copper).

In its response dated September 15, 2011, the applicant stated that the Closed-Cycle Cooling Water System Program will be revised to include opportunistic inspections, at an interval not to exceed 10 years, of representative samples of each combination of material and water treatment program. The applicant also stated that the sample population will be based on the likelihood of corrosion and cracking and will include more than the piping associated with the CCW return check valve. In LRA supplement dated November 4, 2011, the applicant revised the enhancement to the Closed-Cycle Cooling Water System Program to state that representative samples of each combination of material and water treatment program will be visually inspected opportunistically and at least every 10 years.

The staff finds the applicant's response acceptable because opportunistic inspections, with a maximum 10-year inspection interval, of a representative sample of piping and components for corrosion and cracking is capable of detecting component degradation prior to loss of intended functions. The staff's concern described in RAI B2.1.10-1 is resolved. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M21A and finds it acceptable because, when it is implemented, it will include appropriate visual inspections to confirm the effectiveness of water chemistry controls.

Enhancement 2. LRA Section B2.1.10, dated October 25, 2010, includes an additional enhancement in which the applicant stated that procedures will be enhanced to monitor chemistry parameters consistent with EPRI guidelines for glycol-based formulations used for the balance of plant (BOP) and fire pump diesel jacket water cooling systems. In LRA Amendment 2, dated June 16, 2011, the applicant removed this enhancement because the monitoring activity had been incorporated into the existing program. During its audit of the Closed-Cycle Cooling Water System Program, the staff confirmed the consistency with the GALL Report; thus, it finds the applicant's removal of the enhancement acceptable.

Summary. Based on its audit, the staff finds that the program elements for which the applicant claimed consistency with GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M21A. The staff also reviewed the exceptions and justifications associated with the "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements and finds that the AMP, with the exceptions, is adequate to manage the applicable aging effects. In addition, the staff reviewed the enhancement associated with the "detection of aging effects," "monitoring and trending," "acceptance criteria," and "corrective actions" program elements and finds that, when implemented, it will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.10 summarizes operating experience related to the Closed-Cycle Cooling Water System Program. The applicant stated that its review of operating experience has revealed no history of chemistry-related corrosion or fouling issues for the CCW, ESF diesel generator jacket water system, essential chilled water, reactor containment building chilled water, boron thermal regeneration system chilled water, and mechanical auxiliary building chilled water systems. The LRA states an operating experience example in which residue buildup was observed on the outside of a flange in the CCW system return piping from the spent fuel pool heat exchanger. This inspection revealed a through-wall crack in the weld neck flange, which was subsequently weld repaired. The cracked weld showed no signs of loss of material as confirmed by ultrasonic test. The LRA states more operating experience examples in which the BOP diesel jacket water system radiator was replaced due to corrosion and the FPD jacket water system cores have been changed due to corrosion that occurred prior to using the current corrosion inhibitor. The LRA also states that the program is based on the guidance contained in EPRI TR-1007820, which is based on industry-wide operating experience.

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 evaluated and incorporated 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 applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A1.10 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 is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the applicant committed (Commitment No. 5) to enhance the program, as described above (Enhancements 1 and 2), prior to the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Closed-Cycle Cooling Water System Program, the staff determines that the program elements for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of AMP XI.M21A in the GALL Report, Revision 2. In addition, the staff reviewed the exceptions and their justifications and determines that the AMP, with the exceptions, is adequate to manage the applicable aging effects. Also, the staff reviewed the enhancement and confirmed that its implementation—through Commitment No. 5 prior to the period of extended operation—will make the AMP adequate to manage the applicable aging effects. 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).

3.0.3.2.8 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

Summary of Technical Information in the Application. LRA Section B2.1.11 describes the existing Inspection of Overhead Heavy and Light Loads (Related to Refueling) Handling Systems Program as consistent, with an enhancement, with GALL Report AMP XI.M23, "Inspection of Overhead Heavy and Light Loads (Related to Refueling) Handling Systems." The LRA states that the AMP addresses crane, trolley, and hoist structural components, fuel handling equipment, and applicable rails exposed to plant indoor air to manage the effects of loss of material. The LRA also states that the AMP proposes to manage this aging effect through visual inspection activities, which will assess loss of material conditions and visible signs of rail wear.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.M23.

The staff also reviewed the portions of the "parameters monitored or inspected" and "detection of aging effects" program elements associated with the enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this enhancement follows.

Enhancement. LRA Section B2.1.11 states an enhancement to the "parameters monitored or inspected" and "detection of aging effects" program elements. In this enhancement, the applicant stated that procedures will be enhanced to inspect crane structural members for loss of material due to corrosion and rail wear. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M23 and finds it acceptable because, when it is implemented, it will be consistent with the current staff position.

Summary. Based on its audit of the applicant's Inspection of Overhead Heavy and Light Loads (Related to Refueling) Handling Systems Program, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M23. In addition, the staff reviewed the enhancement associated with the "parameters monitored or inspected" and "detection of aging effects" program elements and finds that, when implemented, it will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.11 summarizes operating experience related to the Inspection of Overhead Heavy and Light Loads (Related to Refueling) Handling Systems Program. Plant-specific examples are documented in the plant's condition report records. In the LRA, the applicant stated that no occurrences of wear were experienced on components within the scope of this program. However, the applicant pointed to several instances of corrosion on the surface of various components. Two of these instances involve corroded fasteners on the circulating water gantry crane, and another instance occurred between the bridge walkway and crane girder of the Unit 1 main turbine crane. In each of these instances, the affected components were discovered during the inspection process, and the components were either replaced or cleaned and recoated for protection.

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 evaluated and incorporated 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 applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A1.11 provides the UFSAR supplement for the Inspection of Overhead Heavy and Light Loads (Related to Refueling) Handling Systems Program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the applicant committed (Commitment No. 6) to enhance the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program procedures to inspect crane structural members for loss of material due to corrosion and rail wear prior to the period of extended operation. By letter dated June 2, 2014, the applicant informed the NRC that activities associated with Commitment No. 6 were completed. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancement and confirmed that its implementation—through Commitment No. 6—will make the AMP adequate to manage the applicable aging effects. 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).

3.0.3.2.9 Fire Protection

Summary of Technical Information in the Application. LRA Section B2.1.12 describes the existing Fire Protection Program as consistent, with an exception and enhancements, with GALL Report AMP XI.M26, "Fire Protection." The LRA states that the AMP manages loss of material for fire rated doors, fire dampers, and the halon fire suppression system; cracking and spalling of concrete; loss of material for fire barriers; and hardness, shrinkage, and loss of strength for fire barrier penetration seals. The LRA also states that the AMP will manage these aging effects through periodic visual inspections and functional testing to detect aging effects prior to loss of the components' intended functions.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.M26.

The staff also reviewed the portions of the "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements associated with the exception and enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of the exception and enhancements follows.

Exception. LRA Section B2.1.12 states an exception to the "parameters monitored or inspected" and "detection of aging effects" program elements to conduct functional testing of the halon system every 18 months, with visual inspections performed on a 6-month interval. The LRA states that a review of plant-specific operating experience and corrective action documentation over the last 10 years indicates that no degradation or loss of intended function has occurred between inspections. Revision 2 of GALL Report AMP XI.M26 recommends that periodic functional testing of the halon fire suppression system be performed every 6 months or in accordance with the applicant's NRC-approved Fire Protection Program. The staff reviewed this exception against the corresponding program elements in GALL Report AMP XI.M26 and finds it acceptable because the effectiveness of the 18-month interval for functional testing of the halon system is supported by plant-specific operating experience, and the frequency is consistent with the applicant's current NRC-approved Fire Protection Program, which is consistent with the recommendations in Revision 2 of GALL Report AMP XI.M26.

Enhancement 1. LRA Section B2.1.12 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements. In this enhancement, the LRA states that procedures will be enhanced to provide visual inspection of the halon system for degradation, corrosion, and mechanical damage at least once every 6 months. GALL Report AMP XI.M26 states that periodic visual inspections of the halon fire suppression system are performed to detect any signs of corrosion. GALL Report AMP XI.M26 also states that acceptance criteria for inspection of the halon fire suppression system should include no indications of excessive loss of material due to corrosion and no indication of missing parts, holes, or wear. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M26 and finds it acceptable because, when it is implemented, it will expand the inspection parameters to include specific aspects of the in-scope components that are consistent with the recommendations in the GALL Report.

Enhancement 2. LRA Section B2.1.12 states an enhancement to the "parameters monitored or inspected" and "detection of aging effects" program elements. The LRA states that procedures will be enhanced to provide inspections to detect penetration seal deficiencies, including signs of degradation such as cracking, seal separation, separation of layers of material, and rupture and puncture of seals. GALL Report AMP XI.M26 states that visual inspections of penetration seals should examine for any signs of degradation such as cracking, seal separation from walls and components, separation of layers of material, rupture and puncture of seals caused by increased hardness, and shrinkage due to loss of material. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M26 and finds it acceptable because, when it is implemented, it will expand the inspection parameters to make the program consistent with the GALL Report AMP.

Enhancement 3. LRA Section B2.1.12 states an enhancement to the "detection of aging effects" program element. In this enhancement, the LRA states that procedures will be enhanced to include qualification criteria for individuals performing inspections of fire doors, fire barrier penetration seals, fire barrier walls, ceilings, and floors. GALL Report AMP XI.M26 states that visual inspections are performed by fire protection-qualified personnel of fire barrier walls, ceilings, floors, doors, and other materials in walkdowns. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M26 and finds it acceptable because, when it is implemented, it will provide qualification requirements for personnel conducting inspections so that degradation is detected as part of the inspections of the specified in-scope components, which is consistent with the GALL Report recommendations.

Enhancement 4. LRA Section B2.1.12 states an enhancement to the "acceptance criteria" program element. In this enhancement, the LRA states that procedures will be enhanced to include the following fire barrier inspection acceptance criteria: no cracks, spalling, or loss of material that would prevent the barrier from performing its design function. GALL Report AMP XI.M26 states that acceptance criteria for inspection of fire barrier walls, ceilings, floors, and other materials should include no significant indications of concrete cracking, spalling, or loss of material. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M26 and finds it acceptable because, when it is implemented, it will expand the inspection parameters to make the program consistent with the GALL Report AMP.

Summary. Based on its audit and review of the applicant's Fire Protection Program, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M26. The staff also reviewed the exception associated with the "parameters monitored or inspected" and "detection of aging effects" program elements, and its justification, and finds that the AMP, with the exception, is adequate to manage the applicable aging effects. In addition, the staff reviewed the enhancements associated with the "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.12 summarizes operating experience related to the Fire Protection Program. The LRA states that, in cases where degradation has been observed in fire proofing materials and fire barriers, the applicant assessed the aging-related effects and determined that they were progressing gradually and could be easily detected before a flaw would reach the size that could affect the functionality. The LRA also states an operating experience example in which the applicant observed leakage from the diesel fire pump lubricating oil and the air supply pressure control valve. The LRA states the applicant repaired the associated connections, and that no further leakage has been observed from these locations. The LRA further states that corrosion has been identified on fire doors and door frames. The applicant removed the corrosion and reapplied the coatings.

The staff reviewed operating experience information in the application and during the audit, to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant. 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 evaluated and incorporated 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 applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A1.12 provides the UFSAR supplement for the Fire Protection Program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR, Revision 2, Table 3.0-1. The staff also noted that the applicant committed (Commitment No. 7) to enhance the Fire Protection Program procedures prior to the period of extended operation with the following actions:

- provide visual inspection for corrosion and mechanical damage on halon system components at least once every 6 months
- provide inspections to detect the following penetration seal deficiencies:
  - signs of degradation such as cracking
  - seal separation from walls and components
  - separation of layers of material
  - rupture and puncture of seals
- include qualification criteria for individuals performing inspections of fire doors, fire barrier penetration seals, fire barrier walls, ceilings and floors in accordance with the GALL Report
- include the following fire barrier inspection acceptance criteria: no cracks, spalling, or loss of material that would prevent the barrier from performing its design function
- provide visual inspection for degradation, corrosion, and mechanical damage on halon system components at least once every 6 months

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Fire Protection Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justification and determines that the AMP, with the exception, is adequate to manage the applicable aging effects. Also, the staff reviewed the enhancements and confirmed that their implementation—through Commitment No. 7 prior to the period of extended operation—will make the AMP adequate to manage the applicable aging effects. 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).

3.0.3.2.10 Fire Water System

Summary of Technical Information in the Application. LRA Section B2.1.13, as amended by letters dated June 3, 2014; June 11, 2014; and November 12, 2015, describes the existing Fire Water System AMP as consistent, with exceptions and enhancements, with GALL Report AMP XI.M27, "Fire Water System." The LRA states that the AMP manages loss of material for steel, copper alloy, and stainless steel components in the water-based fire protection systems consisting of piping, fittings, valves, sprinklers, nozzles, hydrants, hose stations, standpipes, and fire water storage tanks exposed to raw water, plant indoor air, atmosphere/weather, and concrete. The LRA also states that the AMP manages loss of material, loss of coating integrity, fouling, and flow blockage through periodic hydrant inspections, fire main flushing, sprinkler inspections, and flow tests performed in accordance with National Fire Protection Association (NFPA) codes and standards, specifically NFPA-25, "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems." The LRA further states that the program includes volumetric examinations and internal inspections of fire water piping. The applicant's changes to the program described in the June 3, 2014, letter are based on its review of LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion under Insulation," and LR-ISG-2013-01, "Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," which were issued subsequent to the submittal of the LRA. The applicant also addressed recurring internal corrosion, as discussed in Section A of LR-ISG-2012-02, and stated that this AMP manages the recurring corrosion of the carbon steel and cast iron components exposed to raw water in the fire protection system. The staff's evaluation of the program's adequacy to manage the recurring loss of material is described below.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.M27.

The staff also reviewed the portions of the "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements associated with the exceptions and enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these exceptions and enhancements follows.

Exception 1. LRA Section B2.1.13 states an exception to the "scope of program" program element. In this exception, the LRA states that while GALL Report AMP XI.M27 provides a program for managing steel components in fire protection systems exposed to water, the applicant's Fire Water System AMP also manages additional materials of construction, specifically copper alloy and stainless steel fire water system components with an internal environment of water. The staff reviewed this exception against the corresponding program element in GALL Report AMP XI.M27 and finds it acceptable because, as described in American Society for Metals (ASM) Handbook Volume 13B, “Corrosion: Materials” (ASM International, 2005), copper alloy and stainless steel components are highly corrosion resistant in a water environment, and the inspections and testing conducted in accordance with NFPA-25 are capable of detecting loss of material in these additional materials to assure the functionality of the fire water system.

Exception 2. LRA Section B2.1.13 states an exception to the “detection of aging effects” program element. In this exception, the LRA states that while GALL Report AMP XI.M27 requires inspection of fire protection systems in accordance with the guidance of NFPA-25 (which specifies annual inspections), the applicant performs power block hose station gasket inspections at least once every 18 months. The staff noted that the visual inspection of hose stations is conducted every 6 months for accessible locations and 18 months for stations that are not accessible during normal operations. The staff reviewed this exception against the corresponding program element in GALL Report AMP XI.M27 and finds it acceptable because the inspection intervals are consistent with the applicant’s current, NRC-approved Fire Protection Program and the applicant’s operating experience for the past 10 years has indicated that no degradation leading to a loss of function has occurred in components inspected at this inspection frequency.

Enhancement 1. LRA Section B2.1.13 stated an enhancement to the “preventive actions,” “parameters monitored or inspected,” and “detection of aging effects” program elements. In this enhancement, the LRA stated that procedures will be enhanced to include volumetric examinations or direct measurement on representative locations of the fire water system to determine pipe wall thickness. Based on the changes to the Fire Water System program as stated in the June 3, 2014, letter, Enhancement 1 is no longer relevant because AMP XI.M27, as modified by LR-ISG-0212-02, recommends conducting volumetric inspections when internal visual inspections detect surface irregularities (incorporated into Enhancement 5) instead of conducting periodic inspections of representative locations.

Enhancement 2. LRA Section B2.1.13 stated an enhancement to the “detection of aging effects” program element. In this enhancement, the LRA stated that procedures will be enhanced to replace sprinklers prior to 50 years in service or field service test a representative sample and test every 10 years thereafter to ensure signs of degradation are detected in a timely manner. Based on the changes to the Fire Water System program as stated in the June 3, 2014, letter, Enhancement 2 is no longer relevant because replacement or testing of sprinklers prior to 50 years in service was incorporated into Enhancement 6.

Enhancement 3. LRA Section B2.1.13, as amended by letter dated June 3, 2014, states an enhancement to the “monitoring and trending” program element. The LRA states that procedures will be enhanced to monitor and trend fire water piping flow parameters recorded during fire water flow tests. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M27, as modified by LR-ISG-2012-02, and finds it acceptable because, when it is implemented, it will be consistent with the GALL Report recommendation that system performance tests are monitored and trended, as specified by the associated plant commitments pertaining to NFPA-25.

Enhancement 4. LRA Section B2.1.13, as amended by letter dated June 3, 2014, states an enhancement to the “scope of program” program element. The LRA states that, prior to the period of extended operation, procedures will be enhanced to manage loss of coating integrity for in-scope internally coated fire water components. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M27, as modified by LR-ISG-2012-02, and LR-ISG-2013-01, and finds it acceptable because, when it is implemented, it will be consistent with the GALL Report recommendation that in-scope internal coatings be managed for loss of coating integrity.

Enhancement 5. LRA Section B2.1.13, as amended by letter dated June 3, 2014, states an enhancement to the "parameters monitored or inspected" program element. The LRA states that procedures will be enhanced to: perform flow testing of each fire water loop every 3 years; conduct followup wall thickness inspections of piping when surface irregularities are detected; conduct volumetric wall thickness measurements on portions of the system that are normally dry, but periodically subject to flow; and to manage loss of coating integrity for coatings installed on the internal surfaces of in-scope fire water components. Enhancement 5 states that flow testing will be performed at least every "three to five years." The staff reviewed Commitment No. 8 and Enhancement 6, which clarify that this testing will be conducted every 3 years. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M27, as modified by LR-ISG-2012-02, and finds it acceptable because, when it is implemented, it will be consistent with the GALL Report recommendations related to conducting tests and inspections of the fire water system.

The staff notes that the applicant identified the portions of the fire water system that are normally dry, but periodically wetted, and not easily drained as being susceptible to recurring internal corrosion and that AMR items citing this aging mechanism have been added for components in LRA Table 3.3.2-17.

Enhancement 6. LRA Section B2.1.13, as amended by letter dated June 3, 2014, states an enhancement to the "detection of aging effects" program element. The LRA states that procedures will be enhanced to perform periodic inspections, tests, and cleaning of portions of the fire water system. The applicant included all of the tests and inspections listed in Table 4a, "Fire Water System Inspection and Testing Recommendations," in AMP XI.M27, as modified by LR-ISG-2012-02. With the exception of the following, the staff concluded that the list of tests and inspections is consistent with Table 4a. For the following, the staff evaluated exceptions or issued RAIs to obtain clarifying information.

- The applicant stated that it will inspect sprinklers every 18 months. NFPA-25 (all references are to the 2011 Edition) Section 5.2.1.1 states that sprinklers should be inspected every 12 months. The staff finds the applicant's proposal acceptable because there is a large enough number of sprinklers installed at the applicant's site sufficient to establish an adverse performance trend, even with plant-specific inspections being completed on an 18-month basis rather than annually.
- The applicant stated that it will inspect the interior of the fire water storage tanks every 5 years. NFPA-25 Section 9.2.6 states that uncoated tank interiors should be inspected every 3 years and coated tank interiors can be inspected every 5 years. It was not clear to the staff whether the fire water storage tanks are internally coated. By letter dated April 13, 2015, the staff issued RAI B2.1.13-2 requesting that the applicant state whether the interior of the fire water storage tanks are coated; and if they are not coated, the basis for why inspecting the tank's interior every 5 years is adequate.

  In its response dated June 11, 2015, the applicant stated that the interior of the fire water storage tank is coated. The applicant revised LRA Sections A1.13 and B2.1.13 and

Commitment No. 8 to state that the interior coated surfaces of the fire water storage tank will be inspected every 5 years in accordance with NFPA-25 Section 9.2.7. If the visual inspections detect "pitting and corrosion below nominal wall depth or failure of tank coatings," the tests cited in NFPA-25 Section 9.2.7 will be conducted. In addition, tank bottom thickness measurements will be conducted every 10 years using ultrasonic techniques.

The staff finds the applicant's response acceptable because the applicant's changes to its program are consistent with AMP XI.M27, as modified by LR-ISG-2012-02, and the frequency of tank inspections and criteria for conducting additional tests (e.g., adhesion testing, spot wet-sponge testing) can result in identifying the extent of potentially degraded coatings. The staff's concern described in RAI B2.1.13-2 is resolved.

- The applicant stated that it will conduct bottom thickness ultrasonic tests of the fire water storage tanks every 10 years. NFPA-25 Sections 9.2.6.4 and 9.2.7 state that tank bottoms should be tested for metal loss (in conjunction with the internal inspections) whenever there is evidence of pitting or corrosion, or failure of the internal coating. Section D, of the June 3, 2014, letter states that for fire water storage tank steel surfaces exposed to raw water, "[n]ondestructive ultrasonic readings are taken to evaluate the wall thickness where there is evidence of pitting or corrosion." In addition, in relation to steel tank bottom surfaces it states, "[b]ottom thickness ultrasonic tests are performed on each tank during the first 10-year period of extended operation." It is not clear to the staff that bottom thickness measurements will be conducted whenever inspections detect pitting, corrosion, or failure of the internal coating of the tank bottom.

  By letter dated April 13, 2015, the staff issued RAI B2.1.13-3 requesting that the applicant state whether bottom thickness measurements will be conducted whenever inspections detect pitting corrosion, or failure of the internal coating of the tank bottom.

  In its response dated June 11, 2015, the applicant stated that it, "will conduct testing in accordance with NFPA-25, 2011 Edition Section 9.2.7 whenever inspections detect pitting and corrosion below nominal wall depth or failure of the tank coatings." The applicant revised LRA Sections A1.13 and B2.1.13 and Commitment No. 8 to address this change.

  The staff finds the applicant's response acceptable because the applicant's changes to its program are consistent with AMP XI.M27, as modified by LR-ISG-2012-02, and inspecting the tank bottom periodically and based on inspection results can result in detecting the extent of potential tank bottom wall thickness loss before loss of intended function of the tank. The staff's concern described in RAI B2.1.13-3 is resolved.

- The applicant stated that it will conduct main drain tests every 18 months. NFPA-25 Section 13.2.5 states that main drain tests should be conducted annually. The applicant did not provide a basis for why conducting main drain tests every 18 months is adequate. By letter dated April 13, 2015, the staff issued RAI B2.1.13-4 requesting that the applicant state the basis for why conducting main drain tests every 18 months is adequate.

  In its response dated June 11, 2015, the applicant stated that main drain tests are currently being conducted every 18 months. The applicant reviewed the results of the last 10 years of testing and did not identify any instances of flow obstructions in the fire system piping.

  The staff noted that, as required by NFPA-25, main drain tests are conducted at every water-based fire protection system riser. The staff also noted that NFPA-25 was written for a broad range of facilities, including those with a few main drain test locations (e.g., a small manufacturing facility) and those with numerous main drain test locations (as is typical for power plants). The staff finds the applicant's response acceptable because: (a) based on plant-specific operating experience there has been no evidence of obstructions in the fire system piping; and (b) if flow blockage is detected in the future, sufficient main drain tests will be conducted to demonstrate whether there is a trend of flow blockage sufficient to conduct the testing every 12 months in lieu of every 18 months. Therefore, there is reasonable assurance that the 18-month inspection interval in lieu of a 12-month inspection interval will not result in a loss of intended function of a portion of the system. The staff's concern described in RAI B2.1.13-4 is resolved.

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M27, as modified by LR-ISG-2012-02, and finds it acceptable because inspections and tests of the fire water system will either be conducted consistent with the recommendations in AMP XI.M27, as modified by LR-ISG-2012-02 or the applicant provided a sufficient basis for exceptions, as discussed above.

Enhancement 7. LRA Section B2.1.13, as amended by letter dated June 3, 2014, states an enhancement to the "detection of aging effects" program element. The LRA states that procedures will be enhanced to conduct followup wall thickness measurements when surface irregularities are detected; and conduct augmented tests or inspections of normally dry but periodically wetted piping segments that cannot be drained or allow water to collect as described in GALL Report AMP XI.M27, as modified by LR-ISG-2012-02. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M27, as modified by LR-ISG-2012-02, and finds it acceptable because, when it is implemented, it will be consistent with the GALL Report recommendations related to augmented wall thickness inspections and augmented inspections of normally dry but periodically wetted piping segments that cannot be drained or allow water to collect.

The staff noted that the applicant's response to RAI 3.0.3-1a, dated June 11, 2015, states that recurring internal corrosion in the fire water system has only occurred in cast iron and carbon steel components that are characterized as normally dry, periodically wetted, and not easily drained. The staff's evaluation of the applicant's use of the Fire Water System AMP to manage recurring internal corrosion of fire water system components is in SER Section 3.3.2.3.17.

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M27, as modified by LR-ISG-2012-02, and finds it acceptable because with the proposed changes to the program described in SER Section 3.0.3.3.5, the program is consistent with AMP XI.M27 and AMP XI.M42.

Enhancement 8. LRA Section B2.1.13, as amended by letter dated June 3, 2014, states an enhancement to the "detection of aging effects," "monitoring and trending," "acceptance criteria," and "corrective action" program elements. The LRA states that procedures will be enhanced to perform inspections and tests of coatings on internal surfaces of in-scope fire water system components. The applicant stated that:

> Procedures will be enhanced to perform coating inspections of the coatings installed on the internals of in-scope fire water components. The coatings are visually inspected every six years, and tested after 12 years of service at a six-year frequency. The coating tests performed are low voltage holiday test per

ASTM D5162, dry film thickness test per ASTM D7091 and Steel Structures Painting Council, and (SSPC) PA-2 and pull off adhesion test per ASTM D4541. Coating inspections and tests are performed by a qualified Nuclear Coating Specialist (NCS) as defined by ASTM D7108 or by Coatings Surveillance Personnel (CSP) under the technical direction of the NCS.

The LRA also states that: (a) coatings will be monitored and trended; (b) the acceptance criteria for coatings will be, "[n]o erosion, corrosion, cavitation erosion, flaking or peeling of the coatings installed on the internals of in-scope fire water components is observed;" and (c) a condition report will be written for coatings that do not meet acceptance criteria. The response to RAI 3.0.3-2:

- stated that visual inspections are conducted on 100 percent of the internal coated surface
- clarified that monitoring and trending will include a pre-inspection review of previous inspection results and the coatings specialist will prepare a post-inspection report that will include the location of all degraded coatings and where possible, photographs indexed to the locations
- stated that coatings that do not meet acceptance criteria "are repaired as needed"

LR-ISG-2013-01, states the following:

(a) When visual inspections detect peeling, delamination, blisters, or rusting, subsequent inspections should be conducted in 4 years. The applicant did not provide a basis for conducting inspections every 6 years regardless of the results of a previous inspection.

(b) The training and qualification of individuals involved in coating inspections is conducted in accordance with an ASTM International standard endorsed in Regulatory Guide 1.54 (RG 1.54), "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants." SRP-LR Table 3.0-1, "FSAR Supplement for Aging Management of Applicable Systems," recommends that the training and qualification requirements for inspection personnel be included in the UFSAR supplement. The applicant did not state the qualification requirements for coating inspections and tests in either the program or UFSAR supplement.

(c) The post-inspection report should include a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where repair can be postponed to the next refueling outage. The applicant's program does not provide this level of detail for areas requiring repair.

(d) In regard to acceptance criteria, blisters are evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 and are limited to a few intact small blisters that are completely surrounded by sound coating bonded to the substrate and the size and frequency should not be increasing between inspections. The applicant did not address acceptance criteria for blisters.

(e) In regard to acceptance criteria, cracking and rusting are to be evaluated by a coating specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54. The applicant did not address acceptance criteria for cracking or rusting.

(f) Coatings that do not meet acceptance criteria are repaired, replaced, or removed; and testing or examination is conducted to ensure that the extent of repaired or replaced coatings encompasses sound coating/lining material. The applicant stated that repairs are conducted "as needed." It is not clear to the staff which degraded conditions that do not meet the acceptance criteria will be repaired. In addition, the applicant did not address followup testing of repaired or replaced coatings to ensure that the extent of repaired or replaced coatings encompasses sound coating material.

By letter dated April 13, 2015, the staff issued RAI B2.1.13-5 requesting that the applicant state:

(a) the basis for conducting inspections every 6 years regardless of the results of a previous inspection

(b) the training and qualification requirements for individuals involved in coating inspections and revise the appropriate portions of the LRA accordingly

(c) whether the post-inspection report will include a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where repair can be postponed to the next refueling outage

(d) the acceptance criteria for blisters

(e) the acceptance criteria for cracking and rusting

(f) which degraded conditions that do not meet the acceptance criteria will be repaired and also state what followup testing will be conducted to ensure that the extent of repaired or replaced coatings encompasses sound coating material.

In its response dated June 11, 2015, the applicant stated the following:

(a) Indications of blistering, cracking, flaking, peeling, delamination, rusting, and physical damage are corrected by removal of the coating to sound base metal and reapplying the coating. "[s]ince the degraded coating has been removed and replaced with new coating the inspection interval is not changed." The applicant also stated that a review of plant-specific operating experience demonstrates that based on the repairs to coatings, coating performance has not been affected.

    The staff did not find the applicant's response acceptable. LR-ISG-2013-01, recommends that when peeling, delamination, blisters, or rusting are observed during inspections or when cracking and flaking that does not meet acceptance criteria is observed, the subsequent inspection interval is 4 years instead of 6 years. Although the RAI response states that the specific degraded coatings will be replaced, with a known degradation mechanism occurring, the staff concluded that inspections should be conducted more frequently than if no degradation was noted in prior inspections. The staff lacked sufficient information to conclude that a 6-year inspection interval is adequate when the extent of coating degradation, similar to the observed degradation that was repaired, is not known. By letter dated October 5, 2015, the staff issued RAI B2.1.13-5a requesting that the applicant state the basis for how it determines the extent of coatings that could be experiencing similar degradation before the next scheduled 6-year interval inspection. The staff's evaluation of the response to this RAI is documented in SER Section 3.0.3.3.5.

(b) Individuals qualified as Nuclear Coating Specialists in accordance with ASTM D7108, "Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist," will conduct coating inspections and tests. The applicant revised LRA Sections A1.13 and B2.1.13 and Commitment No. 8 accordingly.

The staff finds the applicant's response acceptable because it has endorsed ASTM D7108 in RG 1.54 and the standard incorporates appropriate qualification requirements for individuals conducting coating inspections and tests.

(c) "[C]oatings not meeting the acceptance criteria are considered degraded, removed to sound material and replaced with new coatings." LRA Section B2.1.13 was revised to state that degraded coating has been removed to sound metal and replaced with new coatings and the post-inspection report list of locations exhibiting deterioration was clarified to state, "that were remediated."

The staff finds the applicant's response acceptable because there is no need to include a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where repair can be postponed to the next refueling outage in the post-inspection report when all degraded coatings will be repaired prior to returning the component to service.

(d) LRA Section B2.1.13 was revised to include blistering, cracking, delamination, rusting, or physical damage, in the acceptance criteria. The acceptance criteria state that any indication of these coating degradation mechanisms will be found not acceptable. Coatings that do not meet acceptance criteria are "removed to sound material and replaced with new coating."

The staff finds the applicant's response acceptable because the acceptance criteria for degraded coatings now includes all the aging mechanisms recommended in AMP XI.M42, as modified by LR-ISG-2013-01, and repairing the coatings based on any indication of the mechanisms helps ensure that degraded coatings are repaired prior to potentially affecting the component's or downstream component's intended function.

(e) Cracking and rusting are covered in part (d).

The staff's evaluation of cracking and rusting is in part (d).

(f) As described above, "[c]oatings that do not meet the acceptance criteria are considered degraded, removed to sound material and replaced with new coatings." The applicant also stated that the Nuclear Coatings Specialist's oversight of the replacement of the degraded coatings ensures that the extent of repaired or replaced coatings encompasses sound coating material.

The staff's evaluation of acceptance criteria for degraded coatings is in part (d), above. The staff noted that the extent of aging mechanisms including cracking, erosion, cavitation erosion, flaking, rusting, or physical damage are reasonably detectable by visual inspection because they are visible on the surface of the coating. Therefore, the staff finds the applicant's response that a Nuclear Coatings Specialist will oversee the repair or replacement of coatings acceptable because this individual will have adequate training in recognizing these mechanisms. The staff did not find the applicant's response acceptable in regard to detecting the extent of blistering, peeling, and delamination because the extent of these aging mechanisms is not typically detectable by visual inspection alone. The "corrective actions" program element of AMP XI.M42 recommends that testing or examination be conducted to ensure that the extent of repaired coatings/linings encompasses sound material. By letter dated October 5, 2015, the staff issued RAI B2.1.13-5a, requesting that the applicant state whether: (a) testing and examination will be conducted to ensure that replaced coatings encompasses sound coating/lining material; and (b) the testing will include physical techniques in addition to visual examination. The staff's evaluation of the response to this RAI is documented in SER Section 3.0.3.3.5.

By letter dated November 12, 2015, the applicant further revised this enhancement to state: (a) that 100 percent of internal coatings will be inspected; (b) the inspection interval for the fire water storage tanks and other internally coated fire water system components; and (c) the specific edition of referenced inspection standards. The staff's evaluation of these changes is documented in SER Section 3.0.3.3.5.

The staff's concerns described in RAI B2.1.13-5 and RAI B2.1.13-5a are resolved. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M27, as modified by LR-ISG-2012-02, and finds it acceptable because with the proposed changes to the program described in SER Section 3.0.3.3.5, the program is consistent with AMP XI.M27 and AMP XI.M42.

Enhancement 9. LRA Section B2.1.13, as amended by letter dated June 3, 2014, states an enhancement to the "acceptance criteria" program element. The LRA states that procedures will be enhanced to state that the fire water system piping will meet minimum design wall thickness; fouling in sprinklers and associated piping that could cause flow blockage in sprinklers is not acceptable; sprinklers exhibiting signs of leakage or corrosion will be replaced; when representative sample testing of sprinklers inservice for 50 years is conducted, if a sprinkler fails the test, all sprinklers within that population will be replaced; and if sufficient foreign organic or inorganic material to obstruct piping or sprinklers is detected, the material will be removed and its source will be determined and corrected. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M27, as modified by LR-ISG-2012-02, and finds it acceptable because, when it is implemented, it will be consistent with the GALL Report recommendations related to acceptance criteria for pipe wall thickness, sprinkler testing, and debris in fire water systems. By letter dated November 12, 2015, the applicant further revised this enhancement to state that physical testing, where physically possible, will be conducted in conjunction with repair of coatings. The staff's evaluation of these changes is documented in SER Section 3.0.3.3.5. By letter dated June 11, 2015, (RAI 3.0.3-1a response) the applicant addressed recurring internal corrosion in the fire water system as defined by LR-ISG-2012-02. The applicant stated that in the past 10 years (i.e., 2004 to 2014) one occurrence of general, pitting, and crevice corrosion occurred in the wetted portions of the fire water system. The applicant also stated that recurring internal corrosion occurred in the normally dry periodically wetted and not easily drained piping portions of the fire water system. The applicant further stated that no instances of internal corrosion have occurred in normally dry piping in the fire water system from 2004 to 2014. The applicant stated that the augmented visual inspections or flow tests, and volumetric examinations described in Enhancements 5 and 7 will be adequate to detect recurring internal corrosion. The staff finds the applicant's proposal acceptable because, as stated in the applicant's letter of June 3, 2014, changes to its Fire Water System Program, 100 percent of the normally dry periodically wetted and not easily drained piping (i.e., the only portion of the fire water system that is susceptible to recurring internal corrosion) will be visually inspected or flow tested and 20 percent of the piping will be volumetrically examined for wall thickness every 5 years. These inspections or tests are capable of detecting recurring internal corrosion prior to a loss of intended function of the fire water system.

Summary. Based on its audit and review of the applicant's Fire Water System Program and review of the applicant's responses to RAIs B2.1.13-2, B2.1.13-3, B2.1.13-4, B2.1.13-5, and RAI B2.1.13-5a, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M27, as modified by LR-ISG-2012-02, and AMP XI.M42 as modified by LR-ISG-2013-01. The staff also reviewed the exceptions associated with the "scope of program" and "detection of aging effects" program elements, and their justifications, and finds that the AMP, with the exceptions, is adequate to manage the applicable aging effects. In addition, the staff reviewed the enhancements associated with the "scope of program," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," and "corrective actions" program elements and finds that, when implemented; they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.13 summarizes operating experience related to the Fire Water System Program. The LRA states that a review of the past 12 years of operating experience showed no signs of gasket or fire hose degradation due to the inspection intervals of 18 months and 3 years, respectively. The LRA also states that operating experience documented in condition reports indicates that the periodic inspections have been effective in identifying many leakage sites from supply line piping connections, fire hydrants, drain valves, threaded connections, and supply line valve packing. In all of these condition reports, the leakage was corrected, and the degraded components were evaluated or replaced, or both, prior to any loss of intended function of the fire water system.

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 evaluated and incorporated 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 applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A1.13 provides the UFSAR supplement 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, Revision 2, Table 3.0-1, and noted that the recommended UFSAR supplement description for the Fire Water System Program includes "testing or replacement of sprinklers that have been in place for 50 years." Although the applicant has committed (Commitment No. 8) to enhance the Fire Water System Program to include sprinkler replacement, it is not addressed in the UFSAR supplement in LRA Section A1.13. The licensing basis for this program 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 August 15, 2011, the staff issued RAI B2.1.13-1, requesting that the applicant revise the UFSAR supplement to indicate that the Fire Water System Program includes testing or replacement of sprinklers that have been in place for 50 years.

In its response dated September 15, 2011, the applicant stated that LRA Section A1.13 will be revised to include that the program will replace sprinklers prior to 50 years in service or field service test a representative sample of sprinklers and test them every 10 years thereafter during the period of extended operation. By letter dated November 4, 2011, the applicant revised the UFSAR supplement, as described in the letter dated September 15, 2011. The staff finds the applicant's response acceptable because the UFSAR supplement has been revised to include testing or replacement of sprinklers, which have been in place for 50 years; therefore, it is consistent with the corresponding program description in SRP-LR Table 3.0-1. The staff's concern described in RAI B2.1.13-1 is resolved.

Subsequent to the staff's review of the response to RAI B2.1.13-1, the staff reviewed LRA Section A1.13, as amended by letter dated June 3, 2014. The UFSAR supplement does not reflect the following recommendations from SRP-LR Table 3.0-1, as modified by LR-ISG-2012-02 and LR-ISG-2013-01 and, as such, they would not be included in the applicant's licensing basis during the period of extended operation:

- fouling and flow blockage will be managed by the Fire Water System Program
- training and qualification requirements for personnel conducting coating inspections, addressed above in RAI B2.1.13-5
- followup testing requirements of coatings that are repaired

By letter dated April 13, 2015, the staff issued RAI B2.1.13-6 requesting that the applicant state the basis for why the UFSAR supplement does not include a statement that fouling and flow blockage will be managed by the Fire Water System Program, the training and qualification requirements for personnel conducting coating inspections, and the followup testing requirements of coatings that are repaired.

In its response dated June 11, 2015, the applicant revised LRA Section A1.13 to include fouling and flow blockage in the scope of the program and the qualifications of personnel inspecting coatings. However the applicant did not include a statement in LRA Section A1.13 related to performing physical testing where physically possible (i.e., sufficient room to conduct testing) in conjunction with repair or replacement of coatings and linings. By letter dated October 5, 2015, the staff issued RAI B2.1.13-6a, requesting that the applicant state the basis for why the CLB does not include a statement related to followup testing requirements of coatings that are repaired. The staff's evaluation of the response to this RAI is in SER Section 3.0.3.3.5.

The staff also noted that the applicant committed (Commitment No. 8) to implement the procedure changes described in the above Enhancements 3 through 9.

The staff finds that the information in the UFSAR supplement, as amended by letters dated June 3, 2014; June 11, 2015; June 11, 2015; and November 12, 2015, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Fire Water System Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and determines that the AMP, with the exceptions, is adequate to manage the applicable aging effects. Also, the staff reviewed the enhancements and confirmed that their implementation—through Commitment No. 8 prior to the period of extended operation—will make the AMP adequate to manage the applicable aging effects. 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).

3.0.3.2.11 Fuel Oil Chemistry

Summary of Technical Information in the Application. LRA Section B2.1.14 describes the existing Fuel Oil Chemistry Program as consistent with GALL Report AMP XI.M30, "Fuel Oil Chemistry," with exceptions and enhancements. The applicant stated that the program manages loss of material on the internal surface of components in the standby diesel generator (SDG) fuel oil storage and transfer system, diesel fire pump fuel oil system, lighting diesel generator system, and BOP fuel oil system. The program maintains fuel oil quality by controlling contaminants in accordance with applicable ASTM standards, periodic draining of water from fuel oil tanks, visual inspection of internal surfaces during periodic draining and cleaning, ultrasonic wall thickness measurement or pulsed eddy current wall thickness measurement of fuel oil tank bottoms during periodic draining and cleaning, inspection of new fuel oil before it is introduced into the fuel oil tanks, and one-time inspection of a representative sample of components in systems that contain fuel oil by the One-Time Inspection Program. It was also stated that periodic sampling and chemical analysis of the fuel oil inventory at the plant and new fuel oil is performed to monitor fuel oil contaminants.

In a letter dated December 6, 2011, the applicant revised the program description to state that the program includes surveillance and monitoring procedures for maintaining fuel oil quality by controlling contaminants in accordance with the TS and ASTM Standards D 1796, D 2276, and D 4057.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.M30.

The staff also reviewed the portions of the "scope of program," "parameters monitored or inspected," and "acceptance criteria" program elements associated with exceptions or enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these exceptions and enhancements follows.

Exception 1. LRA Section B2.1.14 states an exception to the "scope of program" and "acceptance criteria" program elements. In this exception, the applicant stated that the program specifies that fuel oil particulate concentrations be measured using a 0.8 micron (μm) nominal pore size filter, in accordance with ASTM D2276. The applicant stated that ASTM D2276 provides guidance on determining particulate contamination using a field monitor. The staff reviewed this exception against the corresponding program elements in GALL Report AMP XI.M30 and finds it acceptable because it allows for the determination of particulates, and it is a recommended standard in accordance with GALL Report AMP XI.M30.

Exception 2. LRA Section B2.1.14 states an exception to the "scope of program," "parameters monitored or inspected" and "acceptance criteria" program elements. The LRA states that NUREG-1801 recommends the use of ASTM D2709 in determining water and sediment contamination in diesel fuel. In this exception, the applicant stated that the program uses only ASTM D1796, and not ASTM D2709, for determining water and sediment contamination in diesel fuel. The applicant further stated that ASTM D1796 gives quantitative results, whereas ASTM D2709 testing gives only pass-fail results.

The staff reviewed this exception to the GALL Report and noted that the applicant took exception because this program does not use both ASTMs D 1796 and D 2709, but uses only ASTM D1796. The staff finds this exception acceptable because the GALL Report recommendation calls for either standard to be used to determine water and sediment contamination.

In addition, the LRA states that NUREG-1801 recommends the use of ASTM D4057 for guidance on oil sampling. It was indicated that this standard requires that multi-level sampling be performed for tanks the size of the SDG fuel oil storage tanks (i.e., approximately 65,000 gallons). The STP program does not perform multilevel sampling of the fuel oil storage tanks. Rather, composite samples are taken from the bottom of the fuel oil storage tanks, where contaminants may collect. The applicant further stated that the fuel oil in the other levels of the tank contain less contaminants per volume than the bottom, making sampling away from the bottom less effective in managing fuel oil contaminants.

The staff reviewed this exception to the GALL Report and noted that the applicant took exception to the GALL Report in that multilevel sampling is not performed to obtain samples from the emergency diesel generator fuel oil storage tanks. The staff finds this exception acceptable because the applicant takes a sample from a location at the bottom of the SDG fuel storage tanks, where contaminants will collect. The staff notes that this sampling method allows for more conservative test results, because contaminants in non-circulating tanks such as these tend to settle to the bottom (the multilevel sample is more appropriate for a tank being continuously recirculated). The staff finds this program exception acceptable because the sampling used in the AMP is equivalent to or more conservative than the ASTM standards recommended by the GALL Report AMP XI.M30.

Exception 3. LRA Section B2.1.14 states an exception to the "parameters monitored or inspected" and "acceptance criteria" program elements. The LRA states that NUREG-1801 recommends a filter with a pore size of 3.0 μm be used in the determination of particulates. The applicant's program does not use a filter with a pore size of 3.0 μm. Rather, the program follows the STP TS, which call for the use of ASTM D2276 in that a filter with pore size of 0.8 μm is used for the analysis of fuel oil. The applicant stated that using a filter with a smaller pore size is more conservative, since more contaminants will be captured.

The staff reviewed this exception to the corresponding program elements in GALL Report AMP XI.M30 and noted that the applicant took exception because this program does not use a filter pore size of 3 μm but uses a filter pore size of 0.8 μm. The staff finds this exception acceptable because the use of a 0.8 μm filter is more conservative than the use of a 3.0 μm filter, which is recommended in the GALL Report AMP XI.M30.

Enhancement 1. LRA Section B2.1.14 states an enhancement to the "scope of program" program element. In this enhancement, the applicant stated that the procedures to the Fuel Oil Chemistry Program will be enhanced to extend the scope of the program to include the SDG fuel oil drain tanks. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M30 and finds it acceptable because, when it is implemented, it will make the program consistent with the recommendations in GALL Report AMP XI.M30.

Enhancement 2. LRA Section B2.1.14 states an enhancement to the "scope of program" and "preventive actions" program elements. In this enhancement, the applicant stated that the program procedures will be enhanced to check and remove the accumulated water from the fuel oil drain tanks, day tanks, and storage tanks associated with the SDG, BOP, lighting diesel generator, and fire water pump diesel generators. The applicant further stated that a minimum frequency of water removal from the fuel oil tanks will be included in the procedure. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M30 and finds it acceptable because, when it is implemented, it will make the program consistent with the recommendations in GALL Report AMP XI.M30.

Enhancement 3. LRA Section B2.1.14 states an enhancement to the "preventive actions," "parameters monitored or inspected," and "detection of aging effects" program elements. In this enhancement, the applicant stated that the program procedures will be enhanced to include 10-year periodic draining, cleaning, and inspection for corrosion of the SDG fuel oil drain tanks, lighting diesel generator fuel oil tank, and diesel fire pump fuel oil storage tanks. In addition, procedures will be enhanced to inspect the BOP diesel generator fuel oil day tanks for internal corrosion. The applicant also stated that the procedures will be enhanced to require periodic testing of the lighting diesel generator fuel oil tank, the SDG fuel oil storage tanks, and diesel fuel oil storage tanks for microbiological organisms.

After reviewing this enhancement, the staff determined that more information was needed to determine whether this enhancement will make the program consistent with the recommendations in the GALL Report. By letter dated November 3, 2011, the staff issued RAI B2.1.14-4, which asked the applicant to provide the frequency for draining, cleaning, and inspecting the BOP day tanks.

In its letter dated December 6, 2011, the applicant stated that the BOP day tanks and SDG drain tanks will be drained, cleaned, and inspected on a 10-year frequency. The staff finds this acceptable because it is consistent with the GALL Report.

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M30 and finds it acceptable because when it is implemented it will make the program consistent with the 10-year periodic draining, cleaning, and inspection frequency recommended by GALL Report AMP XI.M30. The staff's concern described in RAI B2.1.14-4 is resolved.

Enhancement 4. LRA Section B2.1.14 states an enhancement to the "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements. In this enhancement, the applicant stated that the program procedures will be enhanced to require analysis for water, biological activity, sediment, and particulate contamination of the diesel fire pump fuel oil storage tanks, the lighting diesel generator fuel oil tank, and the BOP diesel generator fuel oil day tanks on a quarterly basis. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M30 and finds it acceptable because, when it is implemented, it will make the program consistent with the recommendations in GALL Report AMP XI.M30.

Enhancement 5. LRA Section B2.1.14 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that the program procedures will be enhanced to conduct UT or pulsed eddy current thickness examinations to detect corrosion-related wall thinning one time on the tank bottoms for the SDG and diesel fire pump fuel oil storage tanks and the BOP diesel generator fuel oil day tanks. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M30 and finds it acceptable because, when it is implemented, it will make the program consistent with the recommendations in GALL Report AMP XI.M30.

Enhancement 6. LRA Section B2.1.14 states an enhancement to the “monitoring and trending” program element. In this enhancement, the applicant stated that the program procedures will be enhanced to incorporate the sampling and testing of the diesel fire pump fuel oil storage tanks for particulate contamination and water. The program will also be enhanced to incorporate the trending of water, particulate contamination, and microbiological activity in the SDG and diesel fire pump fuel oil storage tanks, the lighting diesel generator fuel oil tank, and the BOP diesel generator fuel oil day tanks. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M30 and finds it acceptable because, when it is implemented, it will make the program consistent with the recommendations in GALL Report AMP XI.M30.

Summary. Based on its audit, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M30. The staff also reviewed the exceptions associated with the “scope of program,” “preventive actions,” “parameters monitored or inspected,” and “acceptance criteria” program elements, and their justifications, and finds that the AMP, with the exceptions, is adequate to manage the applicable aging effects. In addition, the staff reviewed the enhancements associated with the “scope of program,” “preventive actions,” “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” and “acceptance criteria” program elements and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.14 summarizes operating experience related to the Fuel Oil Chemistry Program.

The applicant provided the following information regarding operating experience:

> STP work orders, condition reports, and the chemistry database from 1999 to 2009 related to fuel oil chemistry were reviewed. None were found which documented any type of corrosion. Several occurrences were found in the chemistry database which documented the need to add biocide to the fuel oil due to finding microbiological growth. Condition reports have documented that fuel oil chemistry was out of specification in the following instances:
>
>> Water and fine sediment intrusion in the auxiliary fuel oil storage tank, diesel generator fuel oil storage tank, fire pump fuel oil storage tank, and the vendor fuel oil trailer tanks have been found approximately annually due to various reasons including the tank cleaning work and a predisposition of a floating tank roof to allow water to pass through and into tank. Corrective actions for fuel oil tanks, including additional inspections and the draining from the bottom of tanks after allowing the water and sediment to settle, have been effective in bringing the fuel oil chemistry back into specification limits, as proven during inspection procedures.

The applicant stated that as additional industry and plant-specific applicable experience becomes available, it will be evaluated and incorporated into the program through the condition reporting process or the Operating Experience Program (OEP).

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 evaluated and incorporated operating experience related to this program. By letter dated November 3, 2011, the staff issued RAI B2.1.14-2, which asked the applicant to discuss the acceptable or unacceptable use of biodiesel at STP. In the same letter, the staff issued RAI B2.1.14-3, which requested that the applicant discuss whether the trending of water and sediment measurements has remained the same, increased, or decreased as a result of corrective actions.

In its response to RAI B2.1.14-2, by letter dated December 6, 2011, the applicant stated that the impact of using a biodiesel blend in the STP diesel engines within the scope of license renewal has not been fully evaluated. The applicant also stated that its current strategy is to prevent all concentrations of biodiesel blends from entering the fuel oil system. The applicant stated that it has performed an engineering evaluation of the impact of NRC IN 2009-02, "Biodiesel in Fuel Oil Could Adversely Impact Diesel Engine Performance," and concluded that fuel containing measurable amounts of biodiesel is not acceptable because of potential deleterious effects on reliability. The applicant stated that it does not currently use biodiesel at STP.

The applicant stated further that appropriate actions are taken to ensure that the STP fuel oil supplier does not carry biodiesel in the trucks that supply fuel to STP. In addition, before off-loading fuel oil to the auxiliary fuel oil storage tank, each fuel trailer is tested for biodiesel with the Herguth field kit, which has a 0.5 percent biodiesel lower limit of detection. Finally, the applicant stated that if biodiesel contamination is detected in the STP diesel fuel oil tanks, corrective actions will be performed (i.e., further testing to confirm the presence of biodiesel, filtration of fuel, de-watering, chemical additions).

In its response to RAI B2.1.14-3 by letter dated December 6, 2011, the applicant provided additional information on operating experience for diesel fuel oil. For example, the applicant stated that since 2009, the clear and bright test of vendor delivered fuel failed on four dates: November 11, 2009; December 21, 2010; April 18, 2010; and April 19, 2010. These failures were due to particles in the fuel oil shipments. All shipments were rejected, and the fuel oil in the auxiliary fuel oil storage tank was reported to have remained in specification throughout the period. Due to the concern for fuel oil quality, the applicant has changed fuel oil venders twice. The applicant stated that the latest change occurred in April 2011, and no additional failures of vendor delivered fuel oil have occurred.

Furthermore, the applicant provided additional operating experience on the fire pump storage tank fuel oil. The applicant stated that, on three occasions, particulates measured high out-of-specification in fire pump fuel oil storage tank fuel oil samples. The applicant performed corrective actions to drain the fuel oil and clean the tank. The applicant stated that, since 2007, all fuel oil particulate sample results for the fire pump fuel oil storage tank have been within specification.

The applicant also provided operating experience on the diesel generator fuel oil storage tank fuel oil. In 2004, the particulate sample result of the fuel oil in the tank was high-out-of specification (36 ppm). The applicant stated that the fuel oil in the tank was recirculated through a filter skid, which returned the fuel oil to within specification. Finally, the applicant stated that the particulate was primarily carbonaceous in nature, resulting from normal deterioration of stored fuel oil over time. As a corrective action, the applicant implemented a periodic schedule of fuel oil cleaning using the permanently installed fuel oil filtration skid.

During its review, that 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. Although the applicant has identified instances of abnormal fuel oil chemistry, the operating experience has shown that appropriate corrective actions were taken such that adjustments were made to correct the chemistry conditions. Moreover, the applicant has committed to tank inspections and cleaning to be performed on a 10-year frequency. In addition, the applicant has the means to perform fuel oil cleaning using a filtration skid. The inspection and cleaning frequency will allow detection of degradation in tank internal surfaces, which will minimize contaminants in the fuel oil. The periodic sampling and testing of diesel fuel oil and inspection and cleaning of fuel oil tanks ensure that the program will continue to identify and evaluate fuel oil chemistry and detect potential aging effects. The staff's concerns described in RAIs B2.1.14-2 and B2.1.14-3 are resolved.

Based on its audit and review of the application, the staff finds that the applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A1.14 provides the UFSAR supplement for the Fuel Oil Chemistry 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 3.0-1, and noted that supplement does not list the specific ASTM standards used in the program. The licensing basis for this program for the period of extended operation may not be adequate if the applicant does not incorporate this information into its UFSAR supplement. By letter November 3, 2011, the staff issued RAI B2.1.14-1 requesting that the applicant discuss why the specific ASTM standards used in the program are not listed in the UFSAR supplement.

In its response dated December 6, 2011, the applicant stated that it uses ASTM Standards D1796, D2276, and D4057. The applicant also stated that UFSAR supplement, Section A1.14, and AMP Section B2.1.14 have been revised to include these listed standards.

The staff finds the applicant's response acceptable because the UFSAR supplement was revised to include the ASTM standards used in the program. Therefore, the UFSAR supplement for the Fuel Oil Chemistry Program is consistent with the corresponding program description in SRP-LR Table 3.0-1. The staff's concern described in RAI B2.1.14-1 is resolved.

The staff also noted that the applicant committed (Commitment No. 9) to ongoing implementation of the existing Fuel Oil Chemistry Program for managing aging of applicable components during the period of extended operation. The staff finds that the information in the UFSAR supplement, as amended by the letter dated December 6, 2011, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Fuel Oil Chemistry Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and determines that the AMP, with exceptions, is adequate to manage the applicable aging effects. Also, the staff reviewed the enhancements and confirmed that their implementation—through Commitment No. 9 prior to the period of extended operation—will make the AMP adequate to manage the applicable aging effects. 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 Reactor Vessel Surveillance

Summary of Technical Information in the Application. LRA Section B2.1.15 describes the applicant's existing Reactor Vessel Surveillance Program as consistent, with enhancements, with GALL Report AMP XI.M31, "Reactor Vessel Surveillance."

The LRA states that the AMP addresses management of RV beltline materials exposed to high-energy neutron fluence (neutrons with energy (E) greater than 1.0 MeV) for loss of material toughness due to neutron embrittlement. The LRA states that the AMP is designed to comply with American Society for Testing and Materials (ASTM) standard E 185-82, "Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels," and 10 CFR Part 50, Appendix H. It states that the program manages this aging effect through scheduled removal and testing of material coupons in order to project end-of-life fluence and demonstrate compliance with the Charpy upper-shelf energy (USE) requirements of 10 CFR Part 50, Appendix G, and the pressurized thermal shock (PTS) criteria of 10 CFR 50.61. The LRA also states that the program uses methodologies in RG 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials." The section states that the removal schedule was approved by the NRC and that it will expose capsules to a fluence level greater than that expected at the beltline wall at 60 years of operation. Finally, the section states that actual vendor coupons will be used, but that an exemption in the facility's original license permits use of other than beltline weld material for weld coupons.

Staff Evaluation. The staff reviewed the applicant's claim of consistency, with two enhancements, with GALL Report AMP XI.M31. 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 noted that GALL Report AMP XI.M31 does not follow the standard 10-element format of the other GALL Report AMPs but rather provides eight specific criteria that an acceptable Reactor Vessel Surveillance Program must meet. Therefore, the staff's evaluation followed the eight criteria specific to GALL Report AMP XI.M31 rather than the standard 10-element format. The staff's review of the eight program criteria is discussed below. The evaluations of the criteria and enhancements are discussed along with the respective program criteria to which they apply.

Criterion 1. GALL Report AMP XI.M31, Criterion 1, states that the extent of RV neutron embrittlement, with respect to USE and pressure-temperature (P-T) limits, is projected for 60 years in accordance with RG 1.99, Revision 2. When using RG 1.99, Revision 2, an applicant may use Tables 1 and 2 to project the extent of RV neutron embrittlement for the period of extended operation based on materials' copper and nickel contents, as described in Regulatory Position (RP) 1 in RG 1.99, Revision 2. Or, the applicant may project RV neutron embrittlement using credible surveillance data based on a best fit to the surveillance data, as described in RP 2 in RG 1.99, Revision 2. It is understood that this specific program criterion applies to all ferritic RV beltline materials, specifically those ferritic RV pressure boundary materials projected to undergo exposure to high-energy neutron (E>1.0 MeV) fluence greater than 1×10^{17} n/cm^2 through the end of the period of extended operation.

The applicant's Reactor Vessel Surveillance Program requires that the extent of RV neutron embrittlement—as determined by the USE, the PTS reference temperature (RT_{PTS}), and the adjusted reference temperature (ART) values for the RV beltline materials—be projected for 60 years in accordance with RG 1.99, Revision 2, and 10 CFR 50.61. The Unit 1 and Unit 2 P-T limits are TLAAs that will be managed under the Reactor Vessel Surveillance Program to ensure compliance with TS administrative controls during the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(iii), as described in LRA Section 4.2.4. The staff's review of the P-T limit TLAAs is documented in SER Section 4.2.4. The current Unit 1 and Unit 2 P-T limit curves are valid through 32 effective full-power years (EFPY). They are calculated based, in part, on the ART value for the limiting RV beltline material. The staff determined that the applicant's neutron embrittlement projections, as described in LRA Section 4.2, and the applicant's statement in LRA Section B2.1.15 that data from the Reactor Vessel Surveillance Program will be used to determine P-T limits and end of life (EOL) USE, are consistent with the statement in the GALL Report, Criterion 1, that "the extent of RV neutron embrittlement, with respect to P-T limits and USE, is projected for 60 years in accordance with RG 1.99, Revision 2."

The staff's reviews of the applicant's TLAAs for the USE, RT_{PTS}, ART, and P-T limits are discussed in SER Sections 4.2.2, 4.2.3, and 4.2.4. Based on its review of these TLAAs, the staff determined the need for additional information, which resulted in the issuance of RAIs that affect the evaluations of both the TLAA and this AMP.

By letter dated February 15, 2012, the staff issued RAI 4.2.2-1, asking the applicant to provide details on the procedures used to determine—for all extended beltline materials—the chemistry data, RT_{NDT}, initial USE values, and associated margins to demonstrate that the applicant has applied consistent approaches to determine these material properties and to resolve certain discrepancies in LRA designations of nickel and copper contents for certain beltline components and welds.

In its letter dated April 17, 2012, the applicant responded to RAI 4.2.2-1; the staff's evaluation of this response is documented in SER Sections 4.2.2 and 4.2.3. Based on its evaluation of the information provided by the applicant, the staff's concerns in RAI 4.2.2-1 are resolved. Therefore, the staff has determined that the applicant's USE, RT_{PTS}, and ART projections are acceptable for all RV beltline components.

Criterion 2. GALL Report AMP XI.M31, Criterion 2, states that determinations of neutron embrittlement for RV beltline materials—based on RP 1 in RG 1.99, Revision 2—are subject to the applicable limitations in RP 1.3 of the RG. The limitations are based on material properties, temperature, material chemistry, and neutron fluence. The staff reviewed the applicant's Reactor Vessel Surveillance Program description in LRA Section B2.1.15, as well as the TLAAs related to neutron embrittlement projections for RV beltline materials, and determined that the applicant's neutron embrittlement projections based on RP 1 in RG 1.99, Revision 2, are bounded by the subject limitations in RP 1.3 of RG 1.99, Revision 2. Therefore, the staff determines that the applicant's Reactor Vessel Surveillance Program is consistent with GALL Report AMP XI.M31, Criterion 2.

Criterion 3. GALL Report AMP XI.M31, Criterion 3, states that determinations of neutron embrittlement for RV beltline materials using surveillance data are subject to the applicable bounds of the surveillance data, such as neutron fluence and irradiation temperature. The exposure conditions of the RV are monitored to ensure that they continue to be consistent with those used to project the effects of embrittlement to the end of the period of extended operation.

Therefore, the staff determined that the applicant's Reactor Vessel Surveillance Program is consistent with GALL Report AMP XI.M31, Criterion 3.

Criterion 4. GALL Report AMP XI.M31, Criterion 4, states that all pulled and tested surveillance capsules, unless discarded before August 31, 2000, shall be placed in storage to be saved for possible reconstitution and use. The applicant has removed three capsules (Capsules U, Y, and V) from each RV; three capsules (Capsules X, W, and Z) remain in each RV. The applicant stated that the last withdrawn capsules were removed in 2007. In LRA Section B2.1.15, the applicant stated that the remaining untested surveillance capsules will be stored in the spent fuel pool as spares. However, to ensure that the last capsules, if removed and tested during the period of extended operation for any reason, still meet the test procedures and reporting requirements of ASTM E 185-82, the staff plans to impose a license condition to address this specific concern:

> All capsules in the reactor vessel that are removed and tested must meet the test procedures and reporting requirements of 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 NRC prior to implementation. All capsules placed in storage must be maintained for future insertion. Any changes to storage requirements must be approved by the NRC.

Criterion 5. GALL Report AMP XI.M31, Criterion 5, states that if an applicant has a surveillance program that consists of capsules with a projected fluence of less than the 60-year RV fluence at the end of 40 years, at least one capsule is to remain in the RV and is tested during the period of extended operation. Furthermore, Criterion 5 states that an applicant may either delay withdrawal of the last capsule or withdraw a standby capsule during the period of extended operation (subject to NRC approval of any actual schedule changes) to monitor the effects of long-term exposure to neutron irradiation.

The staff reviewed the description of the applicant's Reactor Vessel Surveillance Program in LRA Section B2.1.15. As discussed in Criterion 6, the applicant stated that it will remove Capsule W for each unit on a current schedule at approximately 16 EFPY for each unit, which is equivalent to a capsule receiving a neutron fluence equal to 59 EFPY. Since the 59 EFPY value is within the allowed range of cumulative neutron fluence at the end of the period of extended operation for each unit, the staff finds that GALL Report AMP XI.M31, Criterion 5, is not applicable.

Criterion 6. GALL Report AMP XI.M31, Criterion 6, states that if an applicant has a surveillance program that consists of capsules with a projected neutron fluence exceeding the 60-year RV fluence at the end of 40 years, the applicant withdraws one capsule at an outage in which the capsule receives a neutron fluence equivalent to the 60-year RV neutron fluence and tests the capsule in accordance with the requirements of ASTM E-185. Any capsules that are left in the RV shall provide meaningful metallurgical data (i.e., the capsule fluence does not significantly exceed the RV fluence at an equivalent of 60 years). Other standby capsules are removed and placed in storage. These standby capsules (and archived test specimens available for reconstitution) would be available for reinsertion into the reactor if additional license renewals are sought (e.g., 80 years of operation). If all surveillance capsules have been removed, operating restrictions are to be established to ensure that the plant is operated under conditions to which the surveillance capsules were exposed. The exposure conditions of the RV are monitored to ensure that they continue to be consistent with those used to project the effects of embrittlement to the EOL. If the RV exposure conditions (neutron flux, spectrum, irradiation temperature, etc.) are altered, then the basis for the projection to 60 years is reviewed; if deemed appropriate, an active surveillance program is re-instituted. Any changes to the RV exposure conditions and the potential need to re-institute a vessel surveillance program must be approved by the staff as required by 10 CFR Part 50, Appendix H, prior to changing the licensing basis.

The staff reviewed the description of the applicant's Reactor Vessel Surveillance Program in LRA Section B2.1.15 and the information in the SE for Unit 1 and Unit 2, "Revision to Reactor Pressure Vessel Surveillance Capsule Withdrawal Schedules," dated August 5, 2009 (ADAMS Accession No. ML091900724). By letter dated August 13, 2008 (ADAMS Accession No. ML082330456), the applicant submitted a request for revising the withdrawal schedules for the two RV surveillance capsules (both are identified as Capsule X) for Unit 1 and Unit 2 for staff review and approval. The purpose of the applicant's submittal was to postpone the capsule withdrawal dates for the two units by one refueling cycle so that the reactor pressure vessel (RPV) capsule withdrawal schedules would not coincide with the schedules for replacement of the respective RV heads. Under the proposed schedule, one capsule per unit will be withdrawn at approximately 16 EFPY during RFOs 1RE16 and 2RE15 for Unit 1 and Unit 2, respectively. The estimated neutron fluence values for each Capsule X are 4.37×10^{19} n/cm^2 (E>1.0 MeV) for Unit 1 and 4.18×10^{19} n/cm^2 (E>1.0 MeV) for Unit 2, or equivalently 59.04 EFPY for the Unit 1 and Unit 2 RVs. The irradiated RV material information from each unit's Capsule X is intended to support the period of extended operation for Unit 1 and Unit 2. By letter dated March 24, 2011, the applicant provided notification of a revision to the schedule for RV material surveillance capsule removal, such that Capsule W will be pulled instead of Capsule X, due to accessibility issues. The estimated neutron fluence exposures of Capsule W are 4.33×10^{19} n/cm^2 (E>1.0 MeV) for Unit 1 and 4.14×10^{19} n/cm^2 (E>1.0 MeV) for Unit 2. These values are still approximately 59 EFPY and are within the allowed range for cumulative neutron fluence at the end of the period of extended operation for both units. The applicant's Reactor Vessel Surveillance Program includes capsules with a projected fluence greater than the 60-year RV fluence at the end of 40 years. Since two capsules (Capsules X and Z) remain for each RV after the removal and testing of Capsule W from the RVs, the applicant has the capability to either delay withdrawal of the last capsule or withdraw a standby capsule during the period of extended operation to monitor the effects of long-term exposure to neutron irradiation (subject to NRC approval of any actual schedule changes). Remaining RV surveillance capsules could potentially be used to provide metallurgically meaningful data. The applicant stated in LRA Section B2.1.15 that the remaining untested capsules will be withdrawn and stored in the spent fuel pool as spares. Therefore, the staff finds that the applicant's Reactor Vessel Surveillance Program is consistent with the GALL Report for Criterion 6.

Criterion 7. GALL Report AMP XI.M31, Criterion 7, states that applicants without in-vessel capsules use alternative dosimetry to monitor neutron fluence during the period of extended operation, as part of the program for RV neutron embrittlement. The applicant will remove each unit's Capsule W when each surveillance capsule has received a neutron fluence equal to the 59 EFPY RV neutron fluence. As stated in LRA Section B2.1.15, the remaining untested surveillance capsules will be withdrawn at that time and stored in the spent fuel pool as spares. At that time, since all surveillance capsules will have been removed, the vessel fluence will be determined by ex-vessel dosimetry.

Enhancement 1. LRA Section B2.1.15, "Enhancements," gives an enhancement regarding Criterion 7, stating that "[p]rocedures will be enhanced to include the withdrawal schedule and analysis of the ex-vessel dosimetry chain."

Pursuant to 10 CFR Part 50, Appendix H, neutron dosimetry is required be present to monitor the RV throughout plant life, and material specimens are required to be used to measure damage associated with the EOL fast neutron fluence exposure of the RV. The neutron sensors contained in surveillance capsules provide the monitoring requirements established by 10 CFR Part 50, Appendix H. In an ex-vessel neutron dosimetry program, passive neutron sensors are located in the reactor cavity so the neutron exposure of the RV can be continuously monitored throughout plant life, as required by Appendix H. The remaining surveillance capsules can be removed and stored onsite, thereby preserving material for future use. An ex-vessel neutron dosimetry program provides the verification of fast neutron exposure distributions within the RV-wall and establishes a mechanism to enable the long-term monitoring of the RV beltline materials. In Table A4-1, "License Renewal Commitments," Commitment No. 10 includes enhancement of the Reactor Vessel Surveillance Program procedures to "include the withdrawal schedule and analysis of the ex-vessel dosimetry chain." Based on Enhancement 1 and License Renewal Commitment No. 10, the staff finds that the applicant's Reactor Vessel Surveillance Program is consistent with GALL Report AMP XI.M31, Criterion 7.

Criterion 8. GALL Report AMP XI.M31, Criterion 8, states that the applicant may choose to demonstrate that the materials in the RV inlet, outlet, and safety injection nozzles (including nozzle-to-shell welds) are not controlling, so that such materials need not be added to the Material Surveillance Program for the license renewal term. The staff's review of the applicant's treatment of the neutron embrittlement TLAA is in SER Section 4.2. As described in the staff's review in SER Section 4.2, the staff finds that the applicant included the materials in the RV inlet, outlet, and safety injection nozzles (including nozzle-to-shell welds) in its Reactor Vessel Surveillance Program and has provided an acceptable demonstration that the effects of aging caused by neutron fluence will be adequately managed for the period of extended operation.

The LRA also contains an enhancement for Criterion 8, which is evaluated next.

Enhancement 2. LRA Section B2.1.15, "Enhancements," gives an enhancement regarding Criterion 8, stating, in part, the following:

> STP will demonstrate that the reactor vessel inlet and outlet nozzles are exposed to a fluence of less than 10^{17} n/cm^2, or will incorporate the ART for the inlet and outlet nozzles with bounding chemistry and fluence values into the P-T limit curves. The program will be enhanced to include the Unit 2 bottom head torus in the RV Surveillance Program. This involves including the Unit 2 bottom head torus in the evaluations for P-T limit curves and compliance with the PTS rule. The program will address the surveillance coupon materials in one of the following manners: (1) add coupon material from the Unit 2, bottom head torus, if available; or (2) use data from similar material at another plant, if available. (3) If inclusion of material from the Unit 2 bottom head torus in the surveillance program is not practical or if data from another plant is not available, Regulatory Guide 1.99 provides methods that can be used, with increased margins to account for uncertainties.

By letters dated April 17, 2012, and July 17, 2012, the applicant provided additional information, which included ART values for nozzle materials and a description of the methodology that will be followed in the development of P-T curves in the period of extended operation. The staff's review of this information is contained in Sections 4.2.2.2 and 4.2.4.2. As discussed in Section 4.2.4.2, the applicant will consider the impact on all ferritic RCPB components, the increase of the limiting ART, and plant-specific embrittlement information from additional surveillance data provided by the Reactor Vessel Surveillance Program when updating the P-T limits. Ferritic RCPB components that are not RV beltline shell materials may have calculated P-T curve limitations, irrespective of the components' neutron fluence values, that are more restrictive than those calculated for RV beltline shell materials. By letter dated July 17, 2012, the applicant stated:

> The development of the revised P-T limit curves to extend the curves beyond 32 EFPY and into the PEO [period of extended operation] will be in accordance with 10 CFR 50 Appendix G. The revised P-T limit curves will consider the effects of neutron embrittlement on the adjusted reference temperature for RV beltline and extended-beltline locations and the higher stresses in the inlet/outlet nozzle corner region. The revised P-T limit curves also will consider the ferritic RCPB components outside the beltline and extended-beltline locations when determining the lowest service temperature.

The staff finds the methodology for revising the P-T limits, in addition to the plan regarding potential inclusion in the surveillance program for the Unit 2 bottom head torus material, in Enhancement 2, acceptable for meeting the requirements of Criterion 8. Based on Enhancement 2 and on the staff's reviews in SER Section 4.2 discussed above, the staff finds that the applicant's Reactor Vessel Surveillance Program is consistent with GALL Report AMP XI.M31, Criterion 8.

Summary. Therefore, based on its review of the applicant's Reactor Vessel Surveillance Program, the staff finds that the program criteria, including the respective enhancements to Criteria 1 and 8, for which the applicant claimed consistency with GALL Report are consistent with the corresponding program criteria of GALL Report AMP XI.M31, "Reactor Vessel Surveillance."

Operating Experience. LRA Section B2.1.15 summarizes operating experience related to the Reactor Vessel Surveillance Program. The applicant stated that its review of plant and industry operating experience provides reasonable assurance that the Reactor Vessel Surveillance Program will be effective in managing the effects of aging so that components within the scope of the program will continue to perform their intended functions consistent with the CLB during the period of extended operation. The applicant cited evaluation results of three surveillance capsules to conclude that the materials met the requirements for continued safe operation, and the cited 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 RV beltline materials. The staff finds that the applicant's conclusion is supported by the staff's approval of the current PTS evaluation and that P-T limits using information from all surveillance data are in accordance with RG 1.99, Revision 2.

The staff reviewed operating experience information in LRA Section B2.1.15 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. 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 and review of the additional information as discussed in SER Section 4.2.2, the staff finds that the applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A.1.15 provides a UFSAR supplement description for the Reactor Vessel Surveillance Program. The staff reviewed the UFSAR supplement description and determined that the UFSAR supplement description of this program ensures that this program will continue to comply with 10 CFR Part 50, Appendix H, and ASTM E 185-82 requirements during the period of extended operation. The staff also notes that the applicant provided a commitment in LRA Appendix A, Table A4-1 (Commitment No. 10), to enhance the Reactor Vessel Surveillance Program procedures prior to entering the period of extended operation to include the following:

- addition of the withdrawal schedule and analysis of the ex-vessel dosimetry chain
- demonstration that the RV inlet and outlet nozzles are exposed to a fluence of less than 10^{17} n/cm^2 or will incorporate the ART for the inlet and outlet nozzles with bounding chemistry and fluence values into the P-T limit curves
- enhancement of the program to include the Unit 2 bottom head torus in the Reactor Vessel Surveillance Program

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). Therefore, the staff determines that the UFSAR supplement description of this program is acceptable.

Conclusion. On the basis of its review of the applicant's Reactor Vessel Surveillance Program, the proposed enhancements, inclusion of Commitment No. 10 in the UFSAR supplement, and the additional information provided by letters dated April 17, 2012, and July 17, 2012, the staff concludes that the program is consistent with the recommendations of GALL Report AMP XI.M31.

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).

3.0.3.2.13 Selective Leaching of Materials

Summary of Technical Information in the Application. LRA Section B2.1.17, as amended by letter dated June 16, 2011, describes the new Selective Leaching of Materials Program as consistent, with exceptions, with GALL Report AMP XI.M33, "Selective Leaching of Materials." The LRA states that the AMP manages loss of material due to selective leaching for copper alloys with greater than 15 percent zinc (Zn) and gray cast iron components exposed to treated water, raw water, and groundwater (buried) within the scope of license renewal. This will be achieved through a one-time inspection (visual and mechanical) of a sample of components for each system, material, and environment combination.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.M33.

For the “scope of program,” “parameters monitored or inspected,” and “detection of aging effects” program elements, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

The GALL Report AMP XI.M33 recommends that “where practical, the inspection includes a representative sample of the system population and 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 its audit, it was not clear to the staff if copper alloy (greater than 15 percent Zn) solenoid valves in LRA Table 3.3.2-7, “Compressed Air System,” are included in the “representative sample” of components to be inspected. By letter dated August 15, 2011, the staff issued RAI B2.1.17-1, requesting that the applicant explain why valves in question were not included in the “representative sample” of components to be inspected.

In its response dated September 15, 2011, the applicant stated that its draft procedure for implementing the Selective Leaching of Materials Program includes the two copper alloy (greater than 15 percent Zn) solenoid valves exposed to internal plant indoor air, and the valves are part of the representative sample. The applicant also stated that one of the two valves will be inspected.

The staff finds the applicant’s response acceptable because the applicant revised its implementing procedure to include the copper alloy (greater than 15 percent Zn) solenoid valves in the representative sample. Inspection of at least one of the valves will ensure that if selective leaching is occurring, the applicant will be able to detect it. The staff’s concern described in RAI B2.1.17-1 is resolved.

GALL Report AMP XI.M33 states, “[w]here practical, the inspection includes a representative sample of the system population and focuses on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin.” The “scope of program” program element description of LRA Section B2.1.17, “Selective Leaching of Materials,” states that the program procedure provides for visual and mechanical inspections for each system, material, and environment combination. However, it was not clear to the staff if the applicant’s program is consistent with the GALL Report AMP because the applicant did not indicate if the components that are the most susceptible to selective leaching are included in the inspection sample. Therefore, by letter dated August 15, 2011, the staff issued RAI B2.1.17-2 requesting that the applicant explain how the sample of components to be inspected for selective leaching are determined such that the bounding or lead components most susceptible to aging are included.

In its response dated September 15, 2011, the applicant stated that it will revise its basis document for the Selective Leaching of Materials Program and the draft implementing procedure to include guidance for sample selection that focuses on bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin.

The staff finds the applicant’s response acceptable because incorporation of the guidance for sample selection will ensure that the components most susceptible to selective leaching are considered. The staff’s concern described in RAI B2.1.17-2 is resolved.

GALL Report AMP XI.M33 recommends that the selective leaching inspections be conducted in the 5-year period prior to the period of extended operation. However, in LRA Section B2.1.17, it states that the program will be implemented during the 10 years prior to the period of extended operation. It appears that the LRA is not consistent with GALL Report AMP XI.M33, in that it does not specify that the inspections will be conducted in the 5-year period prior to the period of extended operation. Therefore, by letter dated August 15, 2011, the staff issued RAI B2.1.17-4 requesting that the applicant state the basis for why inspections conducted before the 5-year period prior to the period of extended operation will be sufficient to determine whether loss of materials due to selective leaching is occurring.

In its response dated September 15, 2011, the applicant stated that it will revise the AMP, UFSAR supplement, and its basis document for the Selective Leaching of Materials Program to state that the Selective Leaching Program will be implemented in the 5-year period prior to the period of extended operation.

The staff finds the applicant's response acceptable because specifying that implementation of the program in the 5 years prior to entering the period of extended operation will make the applicant's program consistent with the GALL Report. The staff's concern described in RAI B2.1.17-4 is resolved.

The staff also reviewed the portions of the "scope of program," "parameters monitored or inspected," and "detection of aging effects" program elements associated with exceptions to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these exceptions follows.

Exception 1. LRA Section B2.1.17 states an exception to the "scope of program" program element. In this exception, the applicant stated that aluminum bronze components are not managed by the Selective Leaching of Materials Program but, rather, are managed by the plant-specific Selective Leaching of Aluminum Bronze Program. The staff reviewed this exception against the corresponding program element in GALL Report AMP XI.M33 and finds it acceptable because a separate program will be used to manage the effects of aging due to selective leaching of aluminum bronze components. The staff's evaluation of the Selective Leaching of Aluminum Bronze Program is documented in SER Section 3.0.3.3.3.

Exception 2. LRA Section B2.1.17 states an exception to the "scope of program," "parameters monitored or inspected," and "detection of aging effects" program elements. In this exception, the applicant stated that in lieu of Brinell hardness testing for components within the scope of this program, it will use other mechanical examinations, such as scraping or chipping, to identify the presence of selective leaching. The staff reviewed this exception against the corresponding program elements in GALL Report AMP XI.M33 and finds it acceptable because the GALL Report, Revision 2, recognizes that mechanical techniques (such as such as destructive testing, chipping, or scraping) are an acceptable means of detecting the presence of selective leaching.

Exception 3. In LRA Amendment 2, dated June 16, 2011, under "parameters monitored or inspected" and "detection of aging effects" program elements, the applicant added an exception stating that flow testing of fire mains is credited for management of selective leaching of buried cast iron valves in the fire protection system in accordance with GALL Report AMP XI.M41, "Buried and Underground Piping and Tanks."

GALL Report AMP XI.M41 recommends that GALL Report AMP XI.M33, "Selective Leaching of Materials," be used to manage selective leaching in addition to the program recommendations in GALL Report AMP XI.M41. The staff noted that LRA Table 3.3.2-17, "Fire Protection System," includes buried hydrants and valves that are constructed of gray cast iron that will be managed for loss of material due to selective leaching. However, it was not clear to the staff that using flow testing of fire mains to manage selective leaching of buried gray cast iron components in the fire protection system is consistent with GALL Report AMP XI.M41. By letter dated August 15, 2011, the staff issued RAI B2.1.17-3, requesting that the applicant explain how flow testing of fire mains will be effective in managing selective leaching of buried in-scope gray cast iron components in the fire protection system.

In its response dated September 15, 2011, the applicant stated that it will revise the AMP, the UFSAR supplement, and the basis document for the Selective Leaching of Materials Program so that selective leaching of buried gray cast iron valves (fire mains) is no longer managed with flow testing. The applicant also stated that the valves (fire mains) will be managed by inspection of a sample set in accordance with the criteria of the Selective Leaching of Materials Program.

The staff finds the applicant's exception and response acceptable because the buried gray cast iron valves will be managed for selective leaching through inspection on a sampling basis. As such, with respect to management of selective leaching for fire mains, the applicant is consistent with the GALL Report; thus, this exception is no longer needed. The staff's concern described in RAI B2.1.17-3 is resolved.

<u>Summary</u>. Based on its audit and review of the applicant's Selective Leaching of Materials Program, and the applicant's responses to RAIs B2.1.17-1, B2.1.17-2, B2.1.17-3, and B2.1.17-4, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M33. The staff also reviewed the exceptions associated with the "scope of program," "parameters monitored or inspected," and "detection of aging effects" program elements, and their justifications, and finds that the AMP, with the exceptions, is adequate to manage the applicable aging effects.

<u>Operating Experience</u>. LRA Section B2.1.17 states that, to date, there have been no reported cases of loss of material attributable to graphitization or dezincification. However, through-wall cracks have been identified in ECW system piping initiated by pre-existing weld defects and propagated by a dealloying phenomenon. The applicant analyzed the effects of the cracking and found that the degradation is slow so that rapid or catastrophic failure is not a consideration and determined that the leakage can be detected before the flaw reaches a limiting size that would affect the intended function of the ECW system.

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 evaluated and incorporated 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 for gray cast iron and copper-zinc components during the period of extended operation. The staff noted that the facility has extensive plant operating experience with selective leaching of aluminum bronze; however, the aging management of components constructed of this material is being addressed with the plant-specific Selective Leaching of Aluminum Bronze Program. See SER Section 3.0.3.3.3 for the staff's evaluation of that program.

Based on its audit and review of the application, the staff finds that the applicant appropriately evaluated plant-specific and industry operating experience. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A1.17 provides the UFSAR supplement for the Selective Leaching of Materials Program. The staff reviewed this UFSAR supplement description of the program, as revised, and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the applicant committed (Commitment No. 12) to implement the new Selective Leaching of Materials Program in the 5 years prior to entering the period of extended operation for managing aging of applicable components. The staff finds that the information in the UFSAR supplement, as amended by LRA Amendment 2, dated June 16, 2011, and in response to RAI B2.1.17-4, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Selective Leaching of Materials Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and determines that the AMP, with the exceptions, is adequate to manage the applicable aging effects for susceptible materials other than aluminum bronze. The staff notes that selective leaching of aluminum bronze components is managed by a plant-specific AMP; the staff's evaluation of that program is documented in SER Section 3.0.3.3.3. 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).

3.0.3.2.14 Buried Piping and Tanks Inspection

Summary of Technical Information in the Application. LRA Section B2.1.18, as amended by letters dated June 16, 2011; June 26, 2014; June 11, 2015; November 12, 2015; May 19, 2016; and June 28, 2016, describes the existing Buried Piping and Tanks Inspection Program as consistent, with exceptions and enhancements, with GALL Report AMP XI.M41, "Buried and Underground Piping and Tanks." The LRA states that the AMP manages loss of material on the external surfaces of steel, stainless steel, copper alloy, and copper alloy containing greater than 8 percent aluminum components that are buried or underground through opportunistic and directed inspections. The LRA also states that preventive and mitigative actions are taken to ensure the pipe is coated, backfilled, and cathodically protected. Annual surveys of the cathodic protection system are conducted to ensure that it is supplying adequate protection to buried piping. The applicant's changes to the program described in its June 26, 2014, letter are based on its review of LR-ISG-2011-03, "Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program (AMP) XI.M41, 'Buried and Underground Piping and Tanks,'" which was issued on August 2, 2012. The applicant's further changes to the program described in its May 19, 2016, and June 28, 2016, letter are based on its review of LR-ISG-2015-01, "Changes to Buried and Underground Piping and Tank Recommendations."

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.M41.

For the “scope of program,” “preventive actions,” and “detection of aging effects” program elements, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

During its audit of the basis document for LRA Section B2.1.18, “Buried Piping and Tanks Inspection,” under the “scope of program” program element, the staff noted that the document identifies the systems containing buried in-scope piping. However, LRA Table 3.3.2-27, “Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2),” includes buried in-scope piping and valves, which were not included under the “scope of program” program element. It was not clear to the staff if all systems containing buried in-scope piping had been included within the Buried Piping and Tanks Inspection Program. Therefore, by letter dated August 15, 2011, the staff issued RAI B2.1.18-1, requesting that the applicant clarify if the buried piping and valves, as listed in LRA Table 3.3.2-27, are within the scope of the Buried Piping and Tanks Inspection Program.

In its response dated September 15, 2011, the applicant stated that there are no piping or valves within systems included only for Criterion 10 CFR 54.4(a)(2) that are managed by the Buried Piping and Tanks Inspection Program. The applicant further stated that the piping in LRA Table 3.3.2-27 that credited the Buried Piping and Tanks Inspection Program for aging management was removed from the scope of license renewal; however, the LRA table had not been updated when the LRA was submitted. The staff reviewed the applicant’s response and determined that additional information was required regarding the nonsafety-related buried nitrogen system piping that is connected to the safety-related AFW storage tank (AFST) via the condensate transfer system. By letter dated October 11, 2011, the staff issued a followup RAI requesting that the applicant provide a reason why the buried nitrogen system piping is no longer within the scope of license renewal.

In its response dated November 4, 2011, the applicant stated that it re-evaluated the termination points of the piping attached to the AFST and found that a seismic anchor exists on the attached safety-related demineralized water piping such that some of the attached nonsafety-related demineralized water piping could be removed from the scope of license renewal. Additionally, the applicant determined that the construction of the AFST precludes the need for equivalent anchors on the remaining attached nonsafety-related piping because the AFST nozzles have welded piping extensions securely braced within the concrete surrounding the stainless steel tank. Based on this review, the applicant concluded that the attached nonsafety-related piping, including the previously in-scope nitrogen piping, does not need to be included within the scope of license renewal for structural integrity attached.

The staff finds the applicant’s response acceptable because the applicant demonstrated that buried nitrogen piping does not have an intended function that would require its inclusion within the scope of license renewal. The staff’s concerns described in RAI B2.1.18-1 are resolved.

During its audit of the basis document for the Buried Piping and Tanks Inspection Program, under the “preventive actions” program element, the staff noted that the document states that backfill for buried piping is consistent with ASTM D448-08 size number 67; however, the implementing procedure allows non-category 1 backfill material above plant elevation 26. GALL Report AMP XI.M41, under the “preventive actions” program element in Table 2a, footnote 5, states that backfill that is located within 6 inches of the pipe that meets ASTM D448-08 size number 67 meets the objectives of SP0169-2007. The staff noted that some buried in-scope piping rises through elevation 26 and up to ground elevation, which is approximately 28 ft. Based on discussions with the applicant’s staff during the AMP audit, it became apparent that non-category 1 backfill may not meet the requirements of ASTM D448-08 size number 67. By letter dated August 15, 2011, the staff issued RAI B2.1.18-2, requesting that the applicant provide an exception to GALL Report AMP XI.M41 if the plant-specific backfill requirements for backfill installed above plant elevation 26 do not meet the requirements of ASTM D448-08 size number 67.

In its response dated September 15, 2011, the applicant stated that the original installation specifications indicated that the fire protection hydrant riser piping above the 26 ft elevation is backfilled with nonsafety-related backfill that may or may not be in accordance with the ASTM 0448-08 size number 67 criteria. The applicant pointed out that the GALL Report AMP allows an applicant to examine the backfill to determine its acceptability and that if it is determined there is no damage to the coating of the buried piping due to backfill then the backfill may be considered acceptable. The applicant stated that it has performed inspections of the fire protection hydrant risers following removal of backfill, and to date, there has been no evidence of damage to the pipe coatings. The applicant concluded, based on the results of these inspections, that the nonsafety-related backfill of riser piping above the 26-ft elevation is considered acceptable; therefore, the fire hydrant riser piping will be managed using flow testing along with the rest of the fire protection system.

The staff finds the applicant's response acceptable because, as allowed for in GALL Report AMP XI.M41, backfill quality may be demonstrated by examining the backfill while conducting inspections when the results of those inspections do not reveal evidence of mechanical damage to pipe coatings due to the backfill. During the audit, the staff independently reviewed the applicant's plant-specific operating experience and did not find any condition reports indicating that coatings have been damaged. Furthermore, the applicant's program contains acceptance criteria for coated piping which states that there should be no evidence of coating degradation, but if coating degradation is present, it may be considered acceptable if it is determined to be insignificant by a qualified individual. The staff notes that the applicant's "acceptance criteria" program element is consistent with the corresponding program element in GALL Report AMP XI.M41. The staff's concern described in RAI B2.1.18-2 is resolved.

In a letter dated June 26, 2014, the applicant informed the staff of changes to the Buried Piping and Tanks Inspection Program in response to ISG-2011-03, "Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program XI.M41, 'Buried and Underground Piping and Tanks.'" These revisions resolve staff's concern described in RAI B2.1.18-4, which requested that the applicant explain why there are no inspections for the underground in-scope oily waste system piping, is no longer relevant.

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 enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these exceptions and enhancements is discussed below.

By letter dated April 22, 2016 the staff issued RAI B2.1.18-6, requesting that the applicant compare the existing Buried Piping and Tanks Inspection Program to the recommendations in LR-ISG-2015-01. In its response dated May 19, 2016, the applicant revised LRA Sections A1.18 and B2.1.18, and associated commitments, as applicable. The staff's evaluation of the exceptions and enhancements is also discussed below.

Exception 1. LRA Section B2.1.18, as amended by letter dated June 16, 2011, states an exception to the “preventive actions” program element. In this exception, the applicant stated that the original installation specification used for backfill did not include the practice of lowering the pipe carefully into the ditch to avoid external coating damage and taking care during backfilling so that rocks and debris do not strike and damage the pipe coating, which are recommended by National Association of Corrosion Engineers (NACE) SP0169-2007, “Control of External Corrosion on Underground or Submerged Metallic Piping Systems,” Section 5.2.3. The staff reviewed this exception against the corresponding program element in GALL Report AMP XI.M41. Notes 5 and 6 of Table 2a in GALL Report AMP XI.41 state:

> [b]ackfill quality may be demonstrated by plant records or by examining the backfill while conducting the inspections conducted in program element 4 of this AMP. Backfill not meeting this standard, in either the initial or subsequent inspections, is acceptable if the inspections conducted in program element 4 of this AMP do not reveal evidence of mechanical damage to pipe coatings due to the backfill.

During the audit, the staff reviewed the applicant’s Buried Piping and Tanks Inspection Program implementing procedure and noted that the procedure contains an instruction to perform a visual inspection of the exterior condition of the buried piping whenever the piping is excavated. This step would alert the applicant to any degradation of the coating. Additionally, the staff noted that the applicant committed to revise its Buried Piping and Tanks Inspection Program specifications to lower coated piping carefully into a trench to avoid external coating damage and to take care during backfilling to prevent rocks and debris from striking and damaging the pipe coating. Therefore, the staff finds that the applicant’s exception is acceptable.

Exception 2. LRA Section B2.1.18, as amended by letter dated June 16, 2011, states an exception to the “preventive actions” program element. In this exception, the applicant stated that coatings were applied in accordance with plant-defined specifications that are consistent with the intent of the American Water Works Association (AWWA) coating standards called out in NACE SP0169-2007. However, the specific AWWA standards were not identified in the plant-defined specifications. The staff reviewed this exception against the corresponding program element in GALL Report AMP XI.M41. Note 2 of Table 2a in GALL Report AMP XI.M41states, “[w]hen provided, coatings are in accordance with Table 1 of NACE SP0169-2007 or Section 3.4 of NACE RP0285-2002.” NACE SP0169-2007, Table 1, refers to AWWA Standard C203, “Coal-Tar Protective Coatings and Linings for Steel Water Pipelines—Enamel and Tape—Hot Applied.” During the audit, the staff reviewed the applicant’s coal tar epoxy coating specification, which includes preparation of surfaces to be coated and protection of adjacent surfaces; furnishing and application of coating materials (including moisture, temperature, and humidity controls); inspection and testing of cleaning and coating operations; and touch-up and repair of damaged or defective coatings. The specification also indicates which coal tar epoxy coatings, removable rust preventives, thinners, solvents, and cleaners are acceptable for use. The staff compared the applicant’s coating specification with AWWA C203 and determined that the applicant’s specification meets the intent of AWWA C203.

In its response to RAI B2.1.18-6 dated May 19, 2016, the applicant stated that its buried stainless steel piping is not coated. AMP XI.M41, as modified by LR-ISG-2015-01, recommends that buried stainless steel piping be coated. The applicant stated that, “[s]oil samples have shown that the uncoated stainless buried piping is not subject to environments that contains chloride.” The staff noted that during its audit of the applicant’s Buried and Underground Piping and Tanks Program, it did not identify any plant-specific operating experience that would indicate that loss of material or cracking was occurring in buried stainless steel piping. In addition, the staff did not detect any nearby sources of environmental materials (e.g., nearby salted roads, industrial complexes, treated cooling towers) that would be deleterious to buried stainless steel piping. Although the applicant did not identify uncoated buried stainless steel piping as an exception, the staff finds the exception acceptable because: (a) soil sampling has not detected environmental chlorides, (b) plant-specific operating experience did not reveal any evidence of loss of material or cracking of buried stainless steel piping, and (c) there are no nearby sources of potential chloride contamination.

In its response to RAI B2.1.18-6 dated May 19, 2016, the applicant did not provide evidence that it will use, as recommended in the "parameters monitored or inspected" program element, a method that has been demonstrated to be capable of detecting cracking. AMP XI.M41 recommends that inspections for cracking are conducted when coating degradation has been noted. Given that the buried stainless steel piping is not coated, it was not clear to the staff why inspections for cracking would not be conducted when buried stainless steel piping is inspected as recommended by the "detection of aging effects" program element of AMP XI.M41. The applicant stated that soil samples have demonstrated that there are no environmental chlorides; however, the purpose of inspections is to verify that degradation does not occur. By letter dated June 28, 2016, the applicant revised its program to state:

> The uncoated stainless steel piping and coated stainless steel piping where the coating is not well-adhered will be inspected using a surface examination or other method capable of detecting cracking. Coatings that are intact, well-adhered, and otherwise sound for the remaining inspection interval, and coatings exhibiting small blisters that are few in number and completely surrounded by sound coating bonded to the substrate do not have to be removed.

The staff finds the changes acceptable because inspecting the surface of stainless steel components for cracks with a surface examination or other method capable of detecting cracking and the criteria for determining when to remove a coating to conduct inspections is consistent with AMP XI.M41, as modified by LR-ISG-2015-01.

Based on its review, the staff finds this exception acceptable.

Enhancement 1. LRA Section B2.1.18, as amended by letter dated June 16, 2011, states an enhancement to the "preventive actions" program element. In this enhancement, the applicant stated that plant specifications will be enhanced to include handling and lowering of the pipe, proper storage and handling techniques for the piping, excavation of trenches and use of qualified backfill, qualification of coatings, and coating of ECW system copper-alloy piping that is embedded in backfill or directly encased in concrete. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M41, which references NACE SP0169-2007. The NACE standard provides recommendations on how to handle and lower piping, qualification of backfill, and qualification of coatings. The staff finds the enhancement acceptable because, when implemented prior to the period of extended operation, it will make the program consistent with the recommendations in GALL Report AMP XI.M41.

Enhancement 2. LRA Section B2.1.18, as amended by letters dated June 16, 2011, June 26, 2014, and May 19, 2016, states an enhancement to the "preventive actions" program element. In this enhancement, the applicant stated that plant procedures will be enhanced to include acceptability of backfill that is located within 6 inches of the pipe consistent with ASTM D448-08 size number 67; annual surveys of the cathodic protection system and bimonthly checks of the rectifier current; bimonthly monitoring of the cathodic protection system rectifier output and subsequent actions if output deviates significantly from target value; annual evaluation of the effectiveness of isolating fittings, continuity bonds, and casing isolation; qualifications for the technicians who perform the plant yard cathodic protection system annual surveys; and an upper limit on cathodic protection polarized potential. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M41, which provides acceptance for backfill located within 6 inches of the buried piping. The Enhancement also references the NACE SP0169-2007 standard. The NACE standard provides guidance on operation and maintenance of cathodic protection systems. The staff finds the enhancement acceptable because, when implemented prior to the period of extended operation, it will make the program consistent with the recommendations in GALL Report AMP XI.M41, as modified by LR-ISG-2015-01.

Enhancement 3. LRA Section B2.1.18, as amended by letters dated June 16, 2011, and June 28, 2016, states an enhancement to the "parameters monitored or inspected" and "detection of aging effects" program elements. In this enhancement, the applicant stated that plant procedures will be enhanced to include: (a) visual inspections of piping; (b) supplemental surface and/or volumetric nondestructive testing if significant degradation is observed; (c) surface exams (or other method capable of detecting cracking) for stainless steel coated and uncoated piping: and (d) the criteria for determining whether a coating should be removed to conduct surface inspections. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M41 that state: (a) that loss of material is monitored by the visual appearance of the exterior of the piping or tank and wall thickness of the piping or tank; (b) visual inspections are supplemented with surface and/or volumetric nondestructive testing if significant indications are observed; (c) the surface of stainless steel components is inspected for cracking; and (d) the criteria for removing coatings for inspections. The staff finds the enhancement acceptable because, when implemented prior to the period of extended operation, it will make the program consistent with the recommendations in GALL Report AMP XI.M41, as modified by LR-ISG-2015-01.

Enhancement 4. LRA Section B2.1.18, as amended by letters dated June 16, 2011, June 26, 2014, and May 19, 2016, states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that plant procedures will be enhanced to include the periodicity of inspections; selection of inspection locations; considerations of risk ranking of buried, underground, and back-filled piping; use of external corrosion direct assessment; credit for opportunistic exams of non-leaking pipes; use of guided wave UT or other advanced inspection techniques for selecting inspection locations; increase in the number of inspections because the site has two units; examination of piping, valves, and bolting when exposed during inspections; two alternatives for inspections of in-scope buried or underground piping; flow testing of fire mains in lieu of direct visual inspections of excavated piping; length of buried piping to be excavated; number of inspections of in-scope buried piping to be conducted depending on the performance of the cathodic protection system, and plant-specific operating experience; number of inspections of the underground in-scope piping; cathodic protection availability and effectiveness criteria; examples of adverse conditions; corrective actions for adverse conditions; expansion of inspection scope when adverse conditions are detected; inspection parameters related to soil and groundwater interactions; the timing of additional inspections when transitioning to a different inspection category in the latter half of the 10-year inspection interval; and the criteria for combining material type inspection categories.

In a letter dated June 26, 2014, the applicant made revisions to the Buried Piping and Tanks Inspection Program in response to issuance of ISG-2011-03, "Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program XI.M41, 'Buried and Underground Piping and Tanks.'" These revisions resolve staff's concerns described in RAI B2.1.18-3, which requested that the applicant describe what actions will be taken for areas of similar material and environment where adverse conditions are not extensive.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M41, as modified by LR-ISG-2011-03 (the review was conducted prior to the issuance of LR-ISG-2015-01), and found it partially acceptable because, when implemented prior to the period of extended operation, it will make the program partially consistent with the recommendations in GALL Report AMP XI.M41. The staff lacked sufficient information for the following. The number of inspections was not consistent with the number recommended in AMP XI.M41. In addition, Enhancement 4 also states, that in order to conduct inspections in accordance with Category E, the soil will have been demonstrated not to be corrosive for the material type. The program does not state how the soil will be demonstrated not to be corrosive (e.g., sample locations, periodicity of sampling, evaluation method). Footnote 7 in Table 4a provides recommendations on demonstrating that the soil is not corrosive. LRA Section B2.1.18 does not state that the program will be consistent with GALL Report AMP XI.M41; therefore, the staff lacks sufficient information to understand how the soil will be demonstrated not to be corrosive.

By letter dated April 13, 2015, the staff issued a followup RAI B2.1.18-5, requesting that the applicant state the basis for why a maximum of 10 inspections will be conducted instead of 11 and state how the soil will be demonstrated to be not corrosive and how soil sampling will be controlled in the CLB.

In its responses dated June 11, 2015, and May 19, 2016, the applicant revised LRA Section B2.1.18 to state the number of inspections that will be conducted for inspection categories C and E, and the number of inspections if the criteria for meeting inspection categories C and E are not met. The applicant stated that the number of inspections is consistent with Table XI.M41-2, "Inspection of Buried and Underground Piping and Tanks." In the response dated June 11, 2015, Enhancement 4 was changed to state that, in the vicinity of where the cathodic protection system does not meet acceptance criteria, the soil will be demonstrated not to be corrosive by: (a) obtaining three sets of soil samples; (b) analyzing the soil for "resistivity, corrosion accelerating bacteria, pH, moisture, chlorides, sulfates, and redox potential"; (c) determining an overall soil corrosivity for each material type; and (d) testing the soil every 10 years.

The staff finds the applicant's response and enhancement acceptable for the program changes because the number of samples, location of samples, parameters evaluated, and the periodicity of soil sampling is consistent with LR-ISG-2015-01, Table XI.M41-2. The staff's concern described in RAI B2.1.18-5 is resolved in regard to proposed changes to the Buried Piping and Tanks Inspection.

Enhancement 5. LRA Section B2.1.18, as amended by letters dated June 16, 2011, and June 26, 2014, states an enhancement to the "monitoring and trending" program element. In this enhancement the applicant stated that plant procedures will be enhanced to include trending of results of the plant yard cathodic protection system annual surveys and wall thickness measurements when followup examinations are conducted. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M41. The staff finds the enhancement acceptable because, when implemented prior to the period of extended operation, it will make the program consistent with the recommendations in GALL Report AMP XI.M41, as modified by LR-ISG-2015-01.

Enhancement 6. LRA Section B2.1.18, as amended by letters dated June 16, 2011; June 26, 2014; and May 19, 2016, states an enhancement to the "acceptance criteria" program element. In this enhancement the applicant stated that plant procedures will be enhanced to include the actions taken if coating degradation is present; qualifications for individuals evaluating the coating degradation; cathodic protection system pipe-to-soil acceptance criteria; alternative cathodic protection system pipe-to-soil acceptance criteria; corrective actions for backfill when the backfill has caused damage to coatings; acceptability of backfill; and acceptance criteria for hydrostatic tests. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M41. The staff finds the enhancement acceptable because, when implemented prior to the period of extended operation, it will make the program consistent with the recommendations in GALL Report AMP XI.M41, as modified by LR-ISG-2015-01.

Enhancement 7. Based on the changes to the Buried Piping and Tanks Inspection Program as stated in the June 26, 2014, letter, Enhancement 7 is no longer relevant given that all buried and underground in-scope piping is subject to inspection regardless of its intended function or contents.

Enhancement 8. LRA Section B2.1.18, as amended by letters dated May 19, 2016, and June 28, 2016, states an enhancement to the "corrective actions" program element. In this enhancement, the applicant stated that plant procedures will be enhanced to include corrective actions associated with nonconforming backfill; criterion for conducting follow-on wall thickness measurements; corrective actions when coatings, backfill, or the condition of the exposed piping does not meet acceptance criteria; the number and timing of additional inspections if acceptance criteria are not met; termination criterion for expansion of sample size inspections; wall thickness measurements will be extrapolated to the next inspection for that pipe section or to the end of the period of extended operation; unacceptable cathodic protection survey results will be documented in the CAP; sources of leakage that are detected during pressure tests will be corrected; and cracking will be evaluated using applicable codes and plant-specific design criteria.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M41. The staff finds the enhancement acceptable because, when implemented prior to the period of extended operation, it will make the program consistent with the recommendations in GALL Report AMP XI.M41, as modified by LR-ISG-2015-01.

Subsequent to the issuance of the LRA, the staff issued LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation." Section F of LR-ISG-2012-02 addressed changes to GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to incorporate inspections of the internal surfaces of in-scope underground piping and piping components in lieu of conducting external volumetric examinations of these components within the scope of AMP XI.M41. By letter dated June 3, 2014, the applicant stated that it will use its Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to conduct internal inspections of in-scope buried or underground piping. The staff finds this acceptable because it is consistent with the recommendations in LR-ISG-2012-02.

Summary. Based on its audit and review of the applicant's responses to RAIs B2.1.18-1, B2.1.18-2, B2.1.18-5, and B2.1.18-6 of the Buried Piping and Tanks Inspection Program, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M41. The staff also reviewed the exceptions associated with the "preventive actions" program element and their justifications, and finds that the AMP, with the exceptions, is adequate to manage the applicable aging effects. In addition, the staff reviewed the enhancements associated with the "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," and corrective actions" program elements and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.18 states that a review of 10 years of plant operating experience produced 30 events associated with buried piping. Nine of these events were related to systems or components in the scope of license renewal. The applicant stated that all of these events were non-corrosion related leaks, making them irrelevant to this program. The applicant also reviewed industry operating experience and identified six relevant events involving buried piping.

The staff reviewed operating experience information to determine whether the applicable aging effects, industry operating experience, 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 to determine whether the applicant had adequately evaluated and incorporated 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 applicant appropriately evaluated both plant-specific and industry operating experience and that the implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. As amended by letter dated June 28, 2016, LRA Section A1.18 provides the UFSAR supplement for the Buried Piping and Tanks Inspection Program.

The staff finds the UFSAR supplement acceptable because it is consistent with Table 3.0-1, "FSAR Supplement for Aging Management of Applicable Systems," in LR-ISG-2015-01. Based on the changes to the Buried Piping and Tanks Inspection Program UFSAR supplement as stated in the May 19, 2016, letter, staff concerns described in RAI B2.1.18-5 are resolved.

The staff also noted that the applicant committed (Commitment No. 13) to enhance the existing Buried Piping and Tanks Inspection Program and begin implementing the program 10 years prior to entering the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Buried Piping and Tanks Inspection Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and determines that the AMP, with the exceptions, is adequate to manage the applicable aging effects. Also, the staff reviewed the enhancements and confirmed that their implementation through Commitment No. 13 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. 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 One-Time Inspection of ASME Code Class 1 Small-Bore Piping

Summary of Technical Information in the Application. LRA Section B2.1.19, as amended by letter dated June 16, 2011, 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 program detects and characterizes cracking of weld locations in small-bore ASME Code Class 1 piping equal to or less than 4-inch nominal pipe size (NPS). The applicant further stated that the program consists of volumetric examination of a representative sample of small-bore piping locations that are susceptible to cracking, which will include both socket welds and butt welds. In addition, the applicant stated that if a qualified, nondestructive volumetric examination technique does not become available for socket welds at the time it performs the inspections, a plant-specific procedure will be used. The applicant also stated that the sample selection will be based on a risk-informed methodology to inspect welds that are susceptible and risk-significant.

Staff Evaluation. During its audit, the staff reviewed the applicant’s claim of consistency with the GALL Report. The staff compared elements one through six of the applicant’s program to the corresponding elements of GALL Report AMP XI.M35.

The applicant stated that it will perform volumetric examination of butt welds that are within the scope of the program. This is consistent with GALL Report AMP XI.M35 regarding volumetric examination of the small-bore piping. For socket welds, the applicant stated that, if no volumetric examination procedure has been incorporated into ASME Code Section XI at the time STP performs inspections, a plant-specific procedure for volumetric examination of socket welds will be used. The staff noted that the volumetric technique, as discussed in the GALL Report, does not preclude applicants from using alternate techniques that may be available to detect signs of failure. The staff also noted that various UT procedures have been developed to examine socket welds. These plant-specific inspection procedures can provide demonstrated techniques that are capable of detecting and characterizing flaws in socket welds. Although not specifically qualified for sizing, such efforts can provide meaningful results that are useful in detecting flaws; therefore, they are useful in managing the effects of aging. Based on its review, the staff finds the applicant’s proposal consistent with GALL Report AMP XI.M35 regarding volumetric examination of the small-bore piping; therefore, it is acceptable.

Regarding the inspection sample size, the applicant stated that it will perform volumetric examination of at least 10 percent of the socket welds up to a maximum of 25 welds in each unit. However, the applicant did not provide any information regarding the socket weld population. In addition, the applicant did not provide any specific information on the butt weld population or the inspection sample size for butt welds. Therefore, the staff needed additional information to determine if the inspection sample size for butt welds is adequate.

By letter dated August 15, 2011, the staff issued RAI B2.1.19-1, requesting that the applicant provide the total population and the inspection sample size for each weld type (e.g., butt welds and socket welds) at each unit and update its program accordingly. In its response dated September 15, 2011, the applicant provided information regarding the population and inspection sample size and a statement indicating that the program will be revised to include the information. However, the staff noted that the applicant did not actually revise its program in the LRA. As a result, the staff had no assurance that the program will contain sufficient information for the staff's review and that the program will be revised in a timely manner.

By letter dated October 18, 2011, the staff issued RAI B2.1.19-2, requesting that the applicant revise LRA Appendix A1.19 and Appendix B2.1.19 to include information regarding the weld population and inspection sample size and to update its UFSAR supplement accordingly.

In its responses dated November 4 and November 17, 2011, to RAI B2.1.19-2, the applicant provided the revised LRA Appendix A1.19 and Appendix B2.1.19. Specifically, the revised program states that there are 182 Class 1 small-bore butt welds and 49 Class 1 small-bore socket welds at Unit 1. The inspection sample size for the Unit 1 butt welds is 19, and the inspection sample size for the Unit 1 socket welds is 5, which represents 10 percent of each weld population. There are 190 Class 1 small-bore butt welds and 59 Class 1 small-bore socket welds at Unit 2. The applicant also indicated that the inspection sample size for the Unit 2 butt welds is 19, and the inspection sample size for the Unit 2 socket welds is 6, which also represents 10 percent for each weld population. The staff noted that the applicant provided specific information on weld populations for butt welds and socket welds for both Unit 1 and Unit 2. The staff also noted that the inspection sample size is at least 10 percent of the weld population for each weld type at each unit. In addition, the staff noted that, based on the applicant's plant-specific operating experience, the guidance of GALL Report AMP XI.M35 recommends the inspection should include 10 percent of the weld population or a maximum of 25 welds for each weld type for each unit. The staff finds the applicant's response acceptable because the inspection sample sizes for the butt and socket welds at each unit are consistent with the sampling guidance in GALL Report AMP XI.M35. The staff's concern related to the inspection sampling aspect in RAIs B2.1.19-1 and B2.1.19-2 is resolved.

The staff noted that the applicant will implement a risk-informed methodology for sample selection to ensure the most susceptible and risk-significant welds are selected. The "detection of aging effects" program element of GALL Report AMP XI.M35 recommends a methodology that selects the most susceptible and risk-significant welds to inspect. The staff finds that the sample selection methodology is consistent with GALL Report AMP XI.M35; therefore, it is acceptable.

The applicant also stated that the inspection will be completed within 6 years prior to the period of extended operation. The staff finds the applicant's proposal consistent with GALL Report AMP XI.M35 regarding timely implementation of the small-bore piping inspections; therefore, it is acceptable.

Exception. The staff noted that the applicant's response dated November 17, 2011, includes amendments to LRA Appendix B2.1.19 that contain an exception that appeared to have been deleted in the previous amendment dated June 16, 2011. The staff needed clarification regarding why the applicant's latest RAI response differed in content from the previous changes shown in its June 16, 2011, submittal. By letter dated December 14, 2011, the staff issued RAI B2.1.19-3 requesting that the applicant revise LRA Appendix A1.19 and Appendix B2.1.19 appropriately to reflect the latest changes or provide a technical basis to justify why previous changes were removed.

In its response dated January 18, 2012, the applicant stated that the June 2011 amendment provided only the sections that were changed, and not the complete Appendix B2.1.19. The applicant explained that the "Exceptions" section of B2.1.19 had not changed and had not been deleted. The applicant further stated that the most recent revision to LRA Appendix A1.19 and Appendix B2.1.19 was provided in the November 17, 2011, letter, which includes the (original) exception in its program.

In its review, the staff noted that the exception proposes the use of outdated industry guidance, "Interim Thermal Fatigue Management Guidance (MRP-24)," that was superseded in 2006 by revised guidance, "Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines (MRP-146)." The staff noted that Materials Reliability Program (MRP)-146 and its supplement contain many improvements in managing thermal fatigue in RCS branch lines. GALL Report, Revision 2, recommends and references the revised guidance, MRP-146. Since the applicant did not provide any technical basis for using outdated industry guidance, the staff finds it unacceptable. By letter dated February 28, 2012, the staff issued RAI B2.1.19-4, requesting that the applicant justify why the outdated guidance in MRP-24 is adequate in managing thermal fatigue in RCS branch lines.

In its response dated March 28, 2012, the applicant provided a revision to LRA Section B2.1.19. The revised section states, "STP follows the guidance in EPRI Report 1011955, Materials Reliability Program: Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines (MRP-146)." The staff noted that the applicant modified an attribute of its program to incorporate the updated industry guidance of MRP-146. The staff finds the program consistent with GALL Report AMP XI.M35, and therefore, acceptable. The staff's concern described in RAI B2.1.19-4 is resolved.

Summary. Based on its audit, and review of the applicant's responses to RAI B2.1.19-1, RAI B2.1.19-2, RAI B2.1.19-3, and RAI B2.1.19-4, the staff finds that elements one through six of the applicant's One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program are consistent with the corresponding program elements of GALL Report AMP XI.M35 and, therefore, are acceptable.

Operating Experience. LRA Section B2.1.19, as amended by letter dated June 16, 2011, summarizes operating experience related to the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program. The applicant indicated that this program is based on relevant plant and industry operating experience. The applicant provided some plant-specific operating experience in the LRA. The applicant further stated that cracking has not been observed for ASME Code Class 1 small-bore piping less than 4-inch NPS based on its plant-specific operating experience review.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant and are evaluated in the GALL Report. As discussed in the audit report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately incorporated and evaluated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant appropriately evaluated plant-specific and industry operating experience. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A1.19, as amended by letter dated June 16, 2011, 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 3.0-1, and noted that the recommended description includes the statement that "[s]hould evidence of cracking be revealed by a one-time inspection, periodic inspection is also proposed, as managed by a plant-specific AMP." However, the applicant's UFSAR supplement for the program, as described in LRA Section A1.19, does not include any statement regarding actions to be taken in the event that evidence of cracking is revealed by the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program. The staff noted that the licensing basis for this program 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 October 18, 2011, the staff issued RAI B2.1.19-2 requesting that the applicant amend the UFSAR supplement to indicate that, if evidence of cracking is revealed by the program, periodic inspections will be implemented under a plant-specific AMP.

In its response dated November 17, 2011, the applicant revised LRA Section A1.19 to include the statement that "[s]hould evidence of cracking be revealed by the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program, periodic inspection will be proposed, as managed by a plant-specific aging management program." The staff finds the applicant's response acceptable because the description in the UFSAR supplement, as amended, adequately captures the need to implement a plant-specific periodic inspection program to manage aging during the period of extended operation if cracking is revealed in ASME Code Class 1 small-bore piping. Therefore, the UFSAR supplement for the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program is consistent with the corresponding program description in SRP-LR Table 3.0-1. The staff's concern related to the UFSAR supplement described in RAI B2.1.19-2 is resolved.

The staff finds that the information in the UFSAR supplement, as amended by letter dated November 17, 2011, 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 Program, the staff finds that the program elements for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.35. 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 External Surfaces Monitoring Program

Summary of Technical Information in the Application. LRA Section B2.1.20, as modified by letters dated February 18, 2014, June 3, 2014, and April 19, 2017, describes the new External Surfaces Monitoring Program as consistent, with exceptions and an enhancement, with GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components." The LRA states that the AMP is a condition monitoring program that includes periodic visual inspections capable of identifying aging effects, inspections capable of detecting loss of preload for non-ASME pressure boundary bolting; leakage for steel, stainless steel, aluminum, and copper alloy components; and inspections capable of detecting hardening and loss of strength for elastomers. The program will also include physical manipulation of elastomers to augment visual inspections to confirm the absence of hardening or loss of strength when appropriate for the component configuration and material. In the February 18, 2014, and June 3, 2014, letters, the applicant revised the program to include management of cracking in stainless steel components (with specific aspects for the RWST), corrosion under insulation, and reduced thermal insulation resistance consistent with the guidance in LR-ISG-2012-02. The April 19, 2017, letter added an enhancement to the program to address managing aging effects associated with non-ASME closure bolting installed in dry gas, compressed air, and diesel exhaust systems.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.M36.

The "detection of aging effects" program element of GALL Report AMP XI.M36 recommends that surfaces that are not readily visible during plant operations and RFOs be inspected when they are made accessible and at intervals that would ensure the components' intended functions are maintained. However, during the audit, the staff found that the applicant's External Surfaces Monitoring Program lacks sufficient detail in its implementing procedure to preclude a component that is inaccessible during normal operation from having its inspection deferred such that it is not inspected at all during the period of extended operation. By letter dated August 15, 2011, the staff issued RAI B2.1.20-4 requesting that the applicant clarify how components that are not readily accessible during plant operations and RFOs will be evaluated and tracked to ensure that the components' intended functions are maintained between inspections and how the inspection interval will be determined.

In its response dated September 15, 2011, the applicant stated that the program basis document and implementing procedures will be revised to do the following:

- include guidance for identifying, logging, and tracking components that are not available for inspection during plant operations and RFOs
- address inspection frequencies for affected components that assure component intended functions are maintained in the period of extended operation
- specify that longer component inspection frequencies may be considered with appropriate justification, such as using results from external inspections of components at different locations with the same materials, environmental conditions, and potential spatial interactions
- ensure that all extended inspection frequencies are justified and documented
- ensure that all inaccessible components are inspected at least once prior to entering the period of extended operation

On December 15, 2011, the applicant informed the staff that these changes had been incorporated. The staff finds the applicant's response acceptable because the program now has an adequate methodology for tracking, monitoring, and inspecting inaccessible components for aging effects to ensure that all inaccessible components are inspected at least once prior to entering the period of extended operation. The staff's concern described in RAI B2.1.20-4 is resolved.

By letter dated February 18, 2014, the applicant addressed the Unit 1 RWST cracking that is discussed in RAI B2.1.16-3 (see SER Section 3.0.3.1.4). The applicant revised the External Surfaces Monitoring Program to state that the external surfaces of the RWSTs will be visually inspected for leakage to detect cracks. The applicant also revised LRA Table 3.2.2-4 to show cracking as an AERM for stainless steel tanks that will be managed by the External Surfaces Monitoring Program. Additional aspects of this issue are discussed in SER Section 3.0.3.1.4.

By letter dated June 3, 2014, the applicant revised the External Surfaces Monitoring Program to include visual inspections that will be used to monitor for corrosion under insulation in indoor and outdoor insulated components. The applicant stated that, "the insulation aluminum jacketing is installed with a vapor barrier and overlapping edges in accordance with plant procedures to create a drainable surface and prevent in-leakage of moisture." The staff notes that the applicant included all of the recommendations for managing corrosion under insulation that are stated in LR-ISG-2012-02. Therefore, the staff finds the applicant provided an acceptable basis for managing this aging mechanism.

Also in its letter dated June 3, 2014, the applicant revised the External Surfaces Monitoring Program by stating it will inspect "100 percent of the accessible components surface for indications of loss of material, leakage, elastomer hardening and loss of strength, and aging effects of protective paints, coatings, caulking, sealants, and insulation for reduced thermal insulation resistance."

The staff also reviewed the portions of the "scope of program" and "detection of aging effects" program elements associated with exceptions to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these exceptions follows.

Exception 1. LRA Section B2.1.20 states an exception to the "scope of program" and "detection of aging effects" program elements. In this exception, the LRA states that the External Surfaces Monitoring Program has expanded the materials inspected to include stainless steel, aluminum, copper alloy, and elastomer external surfaces within the scope of license renewal. The staff noted that although these materials were not included in the scope of Revision 1 of GALL Report AMP XI.M36, these materials have been added to Revision 2 of GALL Report AMP XI.M36. The staff also noted that Revision 2 of GALL Report AMP XI.M36 recommends that metallic materials be managed for loss of material using visual inspection and that elastomers be managed for loss of material and change in material properties using visual inspections and physical manipulations.

The staff reviewed this exception against the corresponding program elements in GALL Report AMP XI.M36 and finds it acceptable because the program includes visual inspections of metallic components for loss of material and visual inspections and physical manipulation of elastomers for loss of strength; these techniques are appropriate for detecting aging for these additional materials prior to a loss of their intended function, consistent with Revision 2 of the GALL Report.

Exception 2. LRA Section B2.1.20 states an exception to the "scope of program" and "detection of aging effects" program elements. In this exception, the LRA states that the External Surfaces Monitoring Program has been expanded to include elastomer hardening and loss of strength among the aging effects to be managed. The staff noted that although these aging effects were not included in the scope of Revision 1 of GALL Report AMP XI.M36, they have been added to Revision 2 of GALL Report AMP XI.M36. The staff also noted that Revision 2 of GALL Report AMP XI.M36 recommends that elastomers be managed for loss of material and change in material properties using visual inspections and physical manipulations.

The staff reviewed this exception against the corresponding program elements in GALL Report AMP XI.M36 and finds it acceptable because the program includes visual inspections and physical manipulation of elastomers; these techniques are appropriate for detecting the additional aging effects of hardening and loss of strength for these materials prior to a loss of their intended function, consistent with Revision 2 of the GALL Report.

Exception 3. LRA Section B2.1.20 states an exception to the “scope of program” and “detection of aging effects” program elements. In this exception, the LRA states that the External Surfaces Monitoring Program has been expanded to include manipulation of elastomers when appropriate to the component material and design. The staff noted that although these inspection techniques were not included in the scope of Revision 1 of GALL Report AMP XI.M36, they have been added to Revision 2 of GALL Report AMP XI.M36. The “parameters monitored or inspected” program element of GALL Report AMP XI.M36, Revision 2, states that the purpose of manual manipulation of elastomers is to reveal changes in material properties to make the visual examination process more effective in identifying aging effects. However, during the audit, the staff noted that the applicant’s External Surfaces Monitoring Program implementing procedure uses the term “may” when describing the augmented manipulation inspection. The staff also noted that the term “may” allows discretion in determining whether to physically manipulate elastomers during visual examinations; therefore, it was not clear whether the applicant’s statement is consistent with the GALL Report recommendations. By letter dated August 15, 2011, the staff issued RAI B2.1.20-1 requesting that the applicant clarify if the physical manipulation of elastomers will always be used to augment visual inspections or to provide the basis for how the hardening and loss of strength aging effects can be consistently detected in elastomers without physically manipulating the material.

In its response dated September 15, 2011, the applicant stated that physical manipulation “will be used” and “is” an augmentation technique to be used with visual inspections of elastomers. The inclusion of this inspection technique was made in LRA Sections B2.1.20 and A1.20 and the program basis document. The staff finds the applicant’s response acceptable because the applicant will augment its visual inspections of elastomers with physical manipulations to detect hardening and loss of strength, consistent with the recommendations in Revision 2 of the GALL Report. The staff’s concern described in RAI B2.1.20-1 is resolved.

The “detection of aging effects” program element of GALL Report AMP XI.M36, Revision 2, recommends that at least 10 percent of the available surface area of elastomeric or polymeric materials be manipulated during inspections. However, the applicant’s External Surfaces Monitoring Program does not include sufficient detail regarding the surface area of elastomeric or polymeric materials that will be physically manipulated during inspections. By letter dated August 15, 2011, the staff issued RAI B2.1.20-3 requesting that the applicant clarify the surface area to be manipulated during inspections.

In its response dated September 15, 2011, the applicant stated that it will revise LRA Sections A1.20 and B2.1.20 and the program basis document to require manipulation of at least 10 percent of the available surface area of elastomeric or polymeric materials. By letter dated

November 4, 2011, the applicant amended LRA Section A1.20 to state that physical manipulation of at least 10 percent of the available surface area will be part of this program. The applicant also amended LRA Section B2.1.20 to state that physical manipulation of at least 10 percent of the available elastomer surface area is used to augment visual inspections. The staff finds the applicant's response acceptable because the program has been revised to include a sufficient surface area for physical manipulation of elastomers such that this inspection technique can assess whether hardening and loss of strength is occurring, consistent with the recommendations in Revision 2 of the GALL Report. The staff's concern described in RAI B2.1.20-3 is resolved.

The staff reviewed Exception 3 against the corresponding program elements in GALL Report AMP XI.M36 and finds it acceptable because the applicant's use of physical manipulation to manage aging for elastomers follows the methodology and techniques in Revision 2 of the GALL Report, as described above, which are capable of detecting aging prior to loss of the component's intended function.

Enhancement. LRA Section B2.1.7, as amended by letter dated April 19, 2017, states an enhancement to the "scope of program" and "detection of aging effects" program elements. In this enhancement, the LRA states that plant procedures will be revised, via Commitment No. 15, to require a leak check of non-ASME closure bolting installed in dry gas, compressed air, and diesel exhaust systems. Techniques such as visual inspection for discoloration, monitoring and trending for pressure decay, leak fluid detection, or when the temperature of the system is higher than ambient conditions, thermography testing, will be conducted. The LRA also states that closure bolting installed in systems where the internal environment consists of atmospheric pressure will be checked for tightness prior to the period of extended operation and once every 6 years thereafter. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M18, the applicable GALL Report AMP for closure bolting. The staff noted that GALL Report AMP XI.M18 recommends conducting leak inspections of closure bolting joints on a refueling outage interval. The staff also noted that checking for tightness results in both an inspection of the bolt head and directly verifies that potential loss of material, cracking, or loss of preload is not occurring, and as a result, checking for tightness is a more rigorous than a visual inspection. The staff finds the enhancement acceptable because: (a) the methods proposed in the enhancement are capable of detecting leakage in air-filled and gas-filled systems; (b) the External Surfaces Monitoring Program conducts inspections on a refueling outage interval consistent with AMP XI.M18; and (c) the test technique for closure bolting installed in systems where the internal environment consists of atmospheric pressure is more rigorous than a leak check and justifies the longer interval between inspections.

Summary. Based on its audits, review of the applicant's responses to RAIs B2.1.20-1, B2.1.20-3, and B2.1.20-4; review of the applicant's External Surfaces Monitoring Program; and review of the program changes stated in the April 19, 2017, letter, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M36. The staff also reviewed the exceptions and enhancement associated with the "scope of program" and "detection of aging effects" program elements, and their justifications, and finds that the AMP, with the exceptions, is adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.20 summarizes operating experience related to the External Surfaces Monitoring Program. The applicant stated that its Condition Reporting Program is used in conjunction with the system walkdowns to identify and resolve issues with plant equipment. The applicant also stated that a review of plant condition reporting documents, as well as other CLB documents, since 1998, was performed to ensure that there is no unique, plant-specific operating experience. The applicant further stated that the Condition Reporting Program was proven to be effective in maintaining the material condition of plant systems, and any additional industry and plant-specific applicable operating experience will be evaluated and incorporated into the program when it becomes available.

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 evaluated and incorporated 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 applicant appropriately evaluated plant-specific and industry operating experience. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A1.20, as amended by letter dated April 19, 2017, provides the UFSAR supplement for the External Surfaces Monitoring Program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the applicant committed (Commitment No. 15) to implement the new External Surfaces Monitoring Program prior to entering the period of extended operation for managing aging of applicable components. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's External Surfaces Monitoring Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and determines that the AMP, with the exceptions, is adequate to manage the applicable aging effects. 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).

3.0.3.2.17 Flux Thimble Tube Inspection

Summary of Technical Information in the Application. LRA Section B2.1.21 describes the existing Flux Thimble Tube Inspection Program as consistent, with enhancements, with GALL Report AMP XI.M37, "Flux Thimble Tube Inspection." The applicant stated that the program manages loss of material by performing wall thickness eddy current inspection of all flux thimble tubes that form part of the RCS pressure boundary. The applicant also stated that the eddy current testing is performed on the portion of the tubes inside the RV. The applicant further stated that the program implements the recommendations of NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors," dated July 26, 1988. The applicant stated that the flux thimble tubes are scheduled to be inspected during each refueling outage and that inspection may be deferred by using an evaluation that considers the actual wear rate. The applicant further stated that wall thickness measurements are trended, wear rates are calculated, and if the measured wear exceeds the acceptance criteria or if the predicted wear (as a measure of percent through-wall) for a given flux thimble tube is projected to exceed the acceptance criteria prior to the next RFO, corrective actions are taken to reposition, cap, or replace the tube. The applicant also stated that the inspection frequency may be revised, as appropriate, based upon operating experience and recommendations from the PWR Owner's Group and that the current acceptance criterion for measured flux thimble wear is 80 percent through-wall.

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.M37. As discussed in the audit report, due to the large number of flux thimble tube repositionings and replacements for Unit 2, the staff also reviewed certain aspects of the applicant's "corrective action" program element. As stated in the audit report, the staff determined the need for additional clarification, which resulted in the issuance of RAIs, as discussed below.

The "monitoring and trending" program element of GALL Report AMP XI.M37 states that the flux thimble tube wall thickness measurements are trended and wear rates calculated based on plant-specific data and a methodology that includes sufficient conservatism to ensure that wall thickness acceptance criteria continue to be met during plant operation between scheduled inspections. Furthermore, the "acceptance criteria" program element of GALL Report AMP XI.M37 states that the acceptance criteria should include allowances for factors such as instrument uncertainty, uncertainties in wear scar geometry, and other potential inaccuracies as applicable to the inspection methodology chosen. The LRA and the onsite documentation related to this program did not clearly address how the program manages the discrepancies between projected wall loss and measured wall loss. In addition, during the audit, the applicant indicated that there was an instance when the applicant took corrective action after the measured wall loss exceeded the acceptance criterion of 80 percent wall loss. The staff was concerned that this may indicate that the program may be under-predicting the amount of wear.

By letter dated August 15, 2011, the staff issued RAI B2.1.21-1, requesting that the applicant provide the following additional information:

- a summary of the flux thimble tube inspection results over the last three inspection outages for each unit and an explanation of how many times the actual wear results were non-conservative when compared to the prior wear projection
- a clarification on how the program re-baselines and adds conservatisms in the new trending basis when the actual inspection results demonstrate that the prior trending basis was not conservative
- a clarification on how the program accounts for instrument and wear uncertainties in the trending basis or acceptance criterion, consistent with the "acceptance criteria" program element recommendation of GALL Report AMP XI.M37 and a justification as to why the current wear projection methodology is conservative

In its response to RAI B2.1.21-1 dated September 15, 2011, the applicant provided inspection summaries for both units and specifically identified for each of the units any instances where wear projections had been non-conservative when compared to actual measured values. The applicant stated that it uses the two most recent measurements and linearly extrapolates to the time when the next measurement will be made. The applicant further stated that in cases where projected wear of a flux thimble is not conservative compared to the measured value, "re-baselining" uses measured wear in projecting future wear; consequently, if a measured wear is higher than expected, the methodology for projecting wear will cause the new projection to be correspondingly higher. The applicant also stated that current eddy current wall thickness measurements are accurate or somewhat conservative, and, as such, it does not add additional uncertainty margin to the measurements. The applicant further stated that Westinghouse Commercial Atomic Power (WCAP) report, WCAP-12866, states that flux thimble tubes have a high residual strength with wall thickness loss on the order of 90 percent; therefore, for conservatism, an acceptance criterion of 80 percent wall loss has been adopted. The applicant also stated that with the exception of three occurrences in 1997, using this methodology, measured flux thimble wear has not exceeded the acceptance criterion; thus, its methodology for predicting flux thimble wear is reasonable and conservative.

The staff reviewed the results from the last three inspection summaries, which covered four refueling outages spanning 6 years of operation, and confirmed that, for Unit 1, wear was detected on 9 tubes out of a total of 58. The staff's review of the last three inspection summaries for Unit 2 confirmed that when the applicant's projected wear was an under-prediction, after re-baselining, the subsequent projection was usually more conservative. Based on this review, the staff finds that the applicant's "monitoring and trending" program element includes sufficient conservatism to ensure that wall thickness acceptance criteria are satisfied between scheduled inspections. In addition, the staff finds the applicant's current acceptance criteria of 80 percent wall loss as acceptable because the applicant's program has been effective (no leakage of thimble tubes); furthermore, the acceptance criteria have not been exceeded since 1997. Therefore, the staff's concerns described in RAI B2.1.21-1 are resolved.

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 enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement. LRA Section B2.1.21 states that the Flux Thimble Tube Inspection Program is an existing program that, with the following enhancements, will be consistent with NUREG-1801, Section XI.M37, "Flux Thimble Tube Inspection."

The enhancements affect the LRA "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," "corrective actions," "confirmation process," and "administrative controls" program elements. Collectively the LRA enhancements state that a new program procedure will be created to implement the following:

- contain provisions to perform a wall thickness eddy current inspection of all flux thimble tubes that form part of the RCS pressure boundary
- evaluate flux thimble tube wear by design engineering personnel and perform corrective actions based on evaluation results after each inspection

- trend wall thickness measurements and calculate wear rates by design engineering personnel
- take corrective actions to reposition, cap, or replace the tube, if the predicted wear (as a measure of percent through-wall) for a given flux thimble tube is projected to exceed the established acceptance criterion prior to the next outage
- include testing and analysis methodology and acceptance criteria
- remove flux thimbles from service to ensure the integrity of the RCS pressure boundary for flux thimble tubes that cannot be inspected over the tube length, that are subject to wear due to restriction or other defects and that cannot be shown by analysis to be satisfactory for continued service

The staff noted that the program enhancements address most of the program elements. By letter dated August 15, 2011, the staff issued RAI B2.1.21-2 requesting that the applicant clarify which portion of each enhancement is the revision or addition to the technical aspects in the existing program and to describe any technical changes and justify their adequacy to manage loss of material of the flux thimble tube.

In its response dated September 15, 2011, to RAI B2.1.21-2, the applicant stated that the existing program meets the technical requirements of NUREG-1801 and that the enhancements to the existing program do not revise or make additions to the technical requirements of the existing program. The applicant also stated that the enhancements are already captured in the STP procedure for implementing this program.

The staff noted that the applicant's enhancements do not affect any of the technical aspects in the existing program. The staff noted that the existing program is consistent with the recommendations of GALL Report AMP XI.M37. Therefore, the staff's concerns described in RAI B2.1.21-2 are resolved.

Summary. Based on its audit, and review of the applicant's responses to RAIs B2.1.21-1 and B.2.1.21-2, the staff finds that elements one through six of the applicant's Flux Thimble Tube Inspection Program are consistent with the corresponding program elements of GALL Report AMP XI.M37 and, therefore, are acceptable.

Operating Experience. LRA Section B2.1.21 summarizes operating experience related to the Flux Thimble Tube Inspection Program. The applicant stated the flux thimble tubes for Unit 1 had original outer diameter of 0.313 inch and were replaced in September of 1989 with thicker tubes with an outer diameter of 0.385 inch. The applicant further stated that the larger diameter tubes reduce the clearance that allowed for flux thimble tube vibration fretting wear in the original 0.313-inch outer-diameter tubes. The applicant also stated that since the change to the 0.385-inch thimbles, there have been no thimble wear actions necessary for Unit 1. The applicant also stated that Unit 2 original flux thimble tubes are the thicker 0.385-inch outer-diameter tubes. The applicant further stated that corrective actions taken for Unit 2 in response to inspection results included repositioning of thimble tubes and replacing 25 thimble tubes with chrome-plated tubes.

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 evaluated and incorporated operating experience related to this program.

During its review, the staff identified operating experience for which it determined the need for additional information and resulted in the issuance of an RAI, as discussed below. Specifically, the staff noted that the LRA does not provide the evaluation results associated with the corrective actions that led to the repositioning and replacing of so many flux thimble tubes.

By letter dated August 15, 2011, the staff issued RAI B2.1.21-3, requesting that the applicant provide the following additional information:

- a summary of the root cause(s) that led to the repositioning and replacement of 25 flux thimble tubes and clarification on whether any aging effect other than loss of material due to wear had resulted in the repositioning or replacement of a flux thimble tube
- a summary of the number of flux thimble tubes that were repositioned or replaced or both during each outage
- a clarification on whether any tubes were repositioned more than once and, if so, an explanation as to how this was factored back in the program's trending basis
- a comparison of the flux thimble tube operating experience at Unit 1 to the operating experience for the thimble tubes at Unit 2 and a description of any engineering evaluations that were performed to reconcile tube wear rate difference between the units
- an identification of appropriate corrective actions that have been performed on the thimble tube at Units 1 and 2

The staff also asked the applicant to demonstrate that the program has adequately implemented the information and lessons obtained from the operating experience and, if the evaluations have identified an item to be further implemented as a program enhancement, to describe the item and the applicant's enhancement associated with it.

In its response dated September 15, 2011, to RAI B2.1.21-3, the applicant stated that Unit 1 did not require any corrective actions due to wear since its flux thimbles were replaced with the larger diameter tubes. The applicant also stated that Unit 2 required multiple tube replacements and repositioning between 1995 and 2010. In addition, as part of its response, the applicant provided a table that summarized the replacement and repositioning history for Unit 2, starting from fall of 1995 to the most recent outage ending May 2010, covering 11 RFOs. The applicant stated that the flux thimble tubes for Unit 2 were repositioned and replaced due to wall thinning; other aging effects were not observed. The applicant also stated that, during this time interval, a total of 34 tubes were repositioned by approximately 2 ½ inches. The applicant also stated that some tubes were repositioned more than once, but those were later replaced. The applicant further stated that during the same interval 25 tubes were replaced by chrome-plated tubes. The applicant stated that the Unit 1 and Unit 2 flux thimbles have design differences, which account for the significant variations in wear rates for the two units.

The staff reviewed the applicant's response to RAI B2.1.21-3 and noted that the root cause, which led to the repositioning and replacement of a large number of flux thimble tubes, was wear; other aging effects were not identified. In addition, the staff noted that the 25 tubes were replaced during a period spanning approximately 15 years. Considering the number of outages, this does not represent an inordinately large number of replacements. The staff also noted that the applicant's Unit 1 and Unit 2 flux thimble tubes have design differences, and agreed that these differences likely accounted for the variations in wear rates. The staff further noted that the applicant adequately implemented the information and lessons obtained by operating experience for Units 1 and 2. Specifically, the applicant's replacement of the Unit 1 flux thimble tubes with larger diameter tubes and the applicant's use of chrome-plated replacement flux thimbles for Unit 2 constitutes evidence that the applicant properly used the program's "operating experience" and "corrective action" elements to account for the relative variances of wear rates observed on Units 1 and 2. Based on this review, the staff finds that the applicant's "operating experience" program element includes sufficient information to determine that the applicant had adequately incorporated and evaluated plant-specific and industry operating experience related to this program. Therefore, the staff's concerns described in RAI B2.1.21-3 are resolved.

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 and the applicant's response to RAI B2.1.21-3, the staff finds that the applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A1.21 provides the UFSAR supplement for the Flux Thimble Tube Inspection Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program, as described in SRP-LR Table 3.0-1.

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 Flux Thimble Tube Inspection Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff concludes that the applicant 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).

3.0.3.2.18 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

Summary of Technical Information in the Application. LRA Section B2.1.22, as revised by letter November 12, 2015, describes the new Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program as consistent, with an exception, with GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," as amended by LR-ISG-2012-02. The LRA states that the AMP addresses the internal surfaces of piping, piping components, ducting, tanks, and other components that are not inspected by other AMPs to manage the effects of cracking, loss of material, and hardening and loss of strength. The LRA also states that the AMP proposes to manage these aging effects through the use of opportunistic visual inspections supplemented by directed inspections to ensure that a sample of 20 percent, up to a maximum of 25 components, of a representative population are inspected during each 10-year period during the period of extended operation. The LRA further states that visual inspections of flexible polymers will be augmented with physical manipulation. Additionally, volumetric evaluations will be performed on tanks and stainless steel components exposed to diesel exhaust.

By letter dated November 12, 2015, the applicant revised its Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program and UFSAR supplement to address loss of coating integrity. The staff's evaluation of these changes is documented in SER Section 3.0.3.3.4.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.M38.

For the "scope of program," "parameters monitored or inspected," and "detection of aging effects" program elements, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The "scope of program" program element in GALL Report AMP XI.M38 recommends that the program apply to water systems other than closed treated water systems (CCCW) and fire water systems. However, during its audit, the staff found that the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program scope applies to water systems including CCCW, fire protection, and both the internal and external surfaces of elastomers. By letter dated August 15, 2011, the staff issued RAI B2.1.22-1 requesting that the applicant review the program's current scope concerning closed-cycle cooling, fire protection, and external surfaces of elastomers. If these components are retained within the current program, the applicant was asked to provide a justification.

In its response dated September 15, 2011, the applicant stated that CCCW copper alloy components were inappropriately listed in the applicant's design basis documents and that this document will be revised. The applicant also stated that external surfaces of elastomers were inadvertently included in the scope of this program and that LRA AMP B2.1.22 and the LRA UFSAR A1.22 will be amended. The applicant also stated that the fire protection system is listed in the program's design basis documents as a system within this AMP. The staff noted that the LRA AMR list does not assign any CCCW-based AMR items to this AMP, so an amended LRA table is not required with the removal of CCCW items from the program's scope. In a followup response dated November 4, 2011, and in the LRA supplement dated December 7, 2011, the applicant's letter amended LRA Section A.1.22 and B2.1.22, deleting external elastomers from the scope and adding the fire water storage tank using a volumetric inspection of the tank bottoms within 5 years prior to entering the period of extended operation and whenever the tanks are drained to manage for loss of material. The staff finds the applicant's response acceptable because the CCCW items were inadvertently listed, and the external elastomeric components are excluded from this scope and are addressed in another AMP. The fire water storage tanks were subsequently removed from the scope of this AMP by letter dated June 3, 2014, in the applicant's response to LR-ISG-2012-02. The staff's concern described in RAI B2.1.22-1 is resolved.

In a letter dated December 15, 2011, in response to RAI SBPB-2-2, the applicant added a visual inspection of the floating seals within the reactor makeup water storage tank to the scope of this program and amended UFSAR supplement Section A1.22 to reflect the change. The applicant also amended LRA Section B2.1.22 to include this new visual inspection and stated that the first inspection will be completed within 5 years prior to the period of extended operation with followup inspections every 5 years thereafter.

The “parameters monitored or inspected” program element in GALL Report AMP XI.M38 recommends that the inspection parameters for elastomers include crazing, scuffing, dimensional change, and exposure of internal reinforcement. However, during its audit, the staff found that the applicant’s Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program omits these aging effects in its design basis document and in the parameters monitored sections of its implementation procedures. By letter dated August 15, 2011, the staff issued RAI B2.1.22-2 requesting that the applicant present a cumulative list of inspection parameters that apply to elastomeric components. In its response dated September 15, 2011, the applicant stated that the inspection parameters for elastomers—including crazing, scuffing, dimensional change, and exposure of internal reinforcement for reinforced elastomers—will be included in the basis document. On December 8, 2011, the applicant informed the staff that these changes had been incorporated.

The staff finds the applicant’s response acceptable because the program now includes an adequate set of inspection parameters that assist in the identification of aging in affected components. The staff’s concern described in RAI B2.1.22-2 is resolved.

The “detection of aging effects” program element in GALL Report AMP XI.M38 recommends that the sample size for manipulation of flexible elastomeric components be at least 10 percent of the available surface area. However, during its audit, the staff found that the applicant’s Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program does not include the sample size associated with the physical manipulation of flexible elastomeric components. By letter dated August 15, 2011, the staff issued RAI B2.1.22-3 requesting that the applicant document the program’s intended sample size associated with physical manipulation of flexible elastomeric components.

In its response dated September 15, 2011, the applicant stated that LRA Appendix A1.22, LRA Appendix B2.1.22, and the LRA basis document’s “detection of aging effects” program element will be revised to include the requirement to manipulate at least 10 percent of available surface area for in-scope elastomers. In a followup response dated November 4, 2011, the applicant amended Appendix A1.22 and Section B2.1.22 to state that physical manipulation of at least 10 percent of elastomer available surface area is part of the program’s inspection technique. The staff finds the applicant’s response acceptable because the elastomer inspection technique using 10 percent of available surface is an adequate method for determining if an aging effect is occurring. The staff’s concern described in RAI B2.1.22-3 is resolved.

The “detection of aging effects” program element in GALL Report AMP XI.M38 recommends that if visual inspections of internal surfaces are not possible, then the applicant needs to provide a plant-specific program. However, during its audit, the staff found that the applicant’s Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program states that, in cases where the internal surfaces are not available for internal examination, volumetric examination may be substituted for visual examination. By letter dated August 15, 2011, the staff issued RAI B2.1.22-4 requesting that the applicant document an enhancement to this program identifying the intent to use volumetric examinations, in lieu of visual inspections, where internal surfaces are inaccessible. The applicant was also requested to reflect this plant-specific approach in the UFSAR supplement.

In its response dated September 15, 2011, the applicant stated that LRA Appendix A1.22 and Appendix B.2.1.22, and the draft implementing procedure, will be revised to state that volumetric examination may be substituted for internal visual inspection in cases where internal surfaces are not available for inspection. In a followup response dated November 4, 2011, the applicant amended LRA Section A1.22 and Section B2.1.22 to state that, where internal surfaces are not available for visual inspection, an internal visual inspection may be substituted with a volumetric examination. The staff finds the applicant's response acceptable because volumetric examinations are an adequate technique to assess if components are subject to cracking or loss of material in metallic components when visual examinations of the internal surfaces are not readily available. During the AMP audit, the staff also reviewed this concern for inaccessible in-scope elastomers, and the applicant's technical staff stated that these items would be evaluated using inspections of accessible equivalent components based on the material, environment, and aging effect. The staff's concern described in RAI B2.1.22-4 is resolved.

The "detection of aging effects" program element in GALL Report AMP XI.M38 recommends that the purpose of manual manipulation of elastomers is to reveal changes in material properties to make the visual examination process more effective in identifying aging effects. However, during its audit, the staff found that the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program states that physical manipulation of elastomers "may" be used to augment visual inspections. By letter dated August 15, 2011, the staff issued RAI B2.1.20-1 requesting that the applicant revise LRA Section B2.1.22 to state that physical manipulation of elastomers "will" be used to augment visual inspections.

In its response dated September 15, 2011, the applicant stated that the use of "may" was inadvertently used instead of "will." In the response, the applicant further stated that the amended text for LRA Appendix A1.22, Appendix B2.1.22, and the LRA basis document AMP XI.M38 (B2.1.22) states that "visual inspections will be augmented by physical manipulation."

The staff finds the applicant's response acceptable because the applicant removed the text that could be discretionary concerning the intent to use physical manipulation, allowing the program to use techniques that can adequately identify if hardening or loss of strength is occurring in polymeric or elastomeric materials. The staff's concern described in RAI B2.1.20-1 is resolved.

Subsequent to the submittal of the LRA, the staff issued LR-ISG-2012-02. Sections B and D of LR-ISG-2012-02 updated the guidance of GALL Report AMPs XI.M38 and XI.M29, respectively. By letter dated June 3, 2014, the applicant revised LRA Sections A1.22, B2.1.22, and Commitment No. 17 to address the updated guidance. The applicant revised its Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to include a minimum sample size for each population of components and to state that opportunistic inspections will continue to be performed after the minimum sample size is reached. The staff finds this acceptable because it is consistent with the recommendations in Section B of LR-ISG-2012-02.

The applicant also revised its Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to perform visual and volumetric inspections of tanks within the scope of GALL Report AMP XI.M29. The internal surfaces of the AFSTs, safety injection RWSTs, and reactor makeup water storage tanks are managed in a manner consistent with Table 4a, "Tank Inspection Recommendations," in LR-ISG-2012-02. The applicant stated that the outdoor stainless steel AFSTs are completely enclosed in concrete. The staff noted that the external tank shell is inaccessible and that LRA Table 3.4.2-6 lists the aging effect as none.

The staff also noted that the external surface of the tank bottom is exposed to the same environment and is also inaccessible; however, it is being managed for loss of material by performing volumetric inspections for the interior of the tank. By letter dated April 13, 2015, the staff issued RAI B2.1.22-6 requesting that the applicant state the basis for ensuring that degradation does not occur on the exterior surfaces of the side walls of the AFSTs.

In its response dated June 11, 2015, the applicant stated that volumetric examination of the AFST sidewalls will be performed from the inside of the tank at the same time as the tank bottom inspections. The applicant also revised LRA Section A.1.22, Section B2.1.22, and Table 3.4.2-6 to incorporate the examination. The staff finds this acceptable because the inspections of the internal surfaces of the tanks are consistent with the recommendations in Section D of LR-ISG-2012-02. 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 an 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.

<u>Exception</u>. LRA Section B2.1.22, as revised by letter dated November 12, 2015, states an exception to “scope of program,” “parameters monitored or inspected,” “detection of aging effects,” and “monitoring and trending” program elements. In this exception, the applicant stated an increase to the scope of the materials inspected to include steel, stainless steel, aluminum, copper alloy, stainless steel-cast austenitic, nickel alloys, glass, and elastomers, and an increase in the scope of aging effects to include hardening and loss of strength for elastomers. Additionally, visual inspections will be augmented by physical manipulation to detect hardening and loss of strength of elastomers, when applicable for the component configuration and material. The exception also includes the addition of volumetric evaluations of tanks and stainless steel components exposed to diesel exhaust to manage loss of material and cracking respectively.

The staff reviewed this exception against the corresponding program elements in GALL Report AMP XI.M38 and finds it acceptable because the inspection techniques and materials are endorsed in the GALL Report, as revised by LR-ISG-2012-02. The staff noted that the applicant did not address polymeric materials in its exception. The staff also noted that LRA Table 3.3.1-19 states that a thermoplastic tank is exposed to an internal environment of Zn acetate and is being managed for cracking by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The staff’s evaluation of this material and environment combination is documented in SER Section 3.3.2.3.19. The staff further noted that SER Sections 3.3.2.3.12, 3.3.2.3.19, 3.3.2.3.24, and 3.3.2.3.27 address the staff’s evaluation of the thermoplastic tank exposed on the external surface to plant indoor air and PVC piping exposed to plant indoor air external, raw water internal, and potable water internal. The evaluation concludes that there is no AERM for the specific polymeric materials exposed to the cited environments. Therefore, given that cracking can be detected without physical manipulation of the polymeric material and the other in-scope polymeric materials have no AERM, it is acceptable that the applicant did not address hardening and loss of strength for polymeric materials.

The applicant revised its Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to address loss of coating integrity in response to staff changes issued in LR-ISG-2013-01, “Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks.” The staff’s evaluation of the applicant’s changes is documented in SER Section 3.0.3.3.5.

Summary. Based on its audit, and review of the applicant's RAI responses, the staff finds that the program elements for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M38, as amended by LR-ISG-2012-02. The staff also reviewed the exception associated with the "scope of program," "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements, and its justification, and finds that the AMP, with the exception, is adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.22 summarizes operating experience related to the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The applicant stated that its use of visual inspections during periodic maintenance, predictive maintenance, surveillance testing, and corrective maintenance demonstrates that internal inspections will be conducted during normal plant activities. The applicant also stated that operating experience is included as an integral part of this program and that there were no unique operating experiences noted since 1998. The applicant further stated that as additional industry and plant-specific applicable operating experience becomes available, it will be evaluated and incorporated into the program through its condition reporting and operating experience programs.

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 evaluated and incorporated 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.

SRP-LR, Revision 2, A.1.2.3.10, "Operating Experience," Section 3, states that "an applicant should commit to a review of future plant-specific and industry operating experience for new programs to confirm their effectiveness." In LRA Table A4-1, "License Renewal Commitment List," the new Internal Surfaces in Miscellaneous Piping and Ducting Components Program does not include a commitment to perform a review of future operating experience to confirm the effectiveness of this program. By letter dated August 15, 2011, the staff issued RAI B2.1.22-5 requesting that the applicant revise LRA Table A4-1, "License Renewal Commitments," item 17, for the Internal Surfaces in Miscellaneous Piping and Ducting Components Program to include a commitment to perform a future review of operating experience to confirm the effectiveness of this program or to justify why such a review is not necessary.

In its response dated September 15, 2011, the applicant stated that Commitment No. 29, in its letter dated June 23, 2011, was revised to include the commitment to evaluate and incorporate new industry and plant-specific operating experience into new AMPs. The applicant also stated that, in a response dated August 18, 2011, LRA Amendment 3 stated that future operating experience will be reviewed to confirm the effectiveness of the One-Time Inspection Program. The staff finds the applicant's response acceptable because the applicant committed to review future operating experience, evaluate it, incorporate it into the program as appropriate, and use operating experience to confirm the effectiveness of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. This method is now consistent with the GALL Report for new AMPs and their use and application for future operating experience. The staff's concern described in RAI B2.1.22-5 is resolved.

The staff finds the applicant's response acceptable because future operating experience will be evaluated and incorporated into the program, which is now consistent with the SRP-LR. The staff's concern described in RAI B2.1.22-5 is resolved.

Based on its audit, review of the application, and review of the applicant's response to RAI B2.1.22-5, the staff finds that the applicant appropriately evaluated plant-specific and industry operating experience. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A1.22, as revised by letter dated June 11, 2015, provides the UFSAR supplement for the Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the applicant committed (Commitment No. 17) to implement the new 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 finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Internal Surfaces in Miscellaneous Piping and Ducting Components Program, the staff determines that the program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff also reviewed the exception and its justification and determines that the AMP, with the exception, is adequate to manage the effects of aging. 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).

3.0.3.2.19 Lubricating Oil Analysis

Summary of Technical Information in the Application. LRA Section B2.1.23 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 manages loss of material and reduction of heat transfer for components within the scope of license renewal that are exposed to lubricating and hydraulic oil. The program includes acceptance criteria based on vendor and industry guidelines for oil chemical and physical properties and for foreign material such as water contamination.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.M39.

The staff also reviewed the portions of the "parameters monitored or inspected" and "acceptance criteria" program elements associated with the exception and enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this exception and these enhancements follows.

Exception. LRA Section B2.1.23 states an exception to the "parameters monitored or inspected" program element. In this exception, the applicant stated that the GALL Report recommends using particle-counting test methods to detect evidence of abnormal wear rates or excessive corrosion for lubricating oil in components subject to periodic oil changes. The applicant stated that analysis of the SDG oil for total particle count does not yield an accurate count because of the dark color of the oil. Instead of particle count testing, the applicant performs an analysis for metal particles by ferrography on a quarterly basis with results that provide indication as to the amount and type of wear particles contained within the oil. The staff reviewed this exception against the corresponding program element in GALL Report AMP XI.M39 and finds it acceptable because the ferrography technique is able to determine relative concentrations of midsize (less than 1 to 250 μm) particles found in lubricating oil. Additionally, ferrography has a similar range of particle size detection as the particle-counting test method.

In addition, the LRA states that the GALL Report recommends determining flash points for oils in components that do not have regular oil changes. The applicant stated that flash point is not determined for sampled oil from the AFW turbine, BOP diesel generator, or feedwater isolation valve hydraulic oil. It was further reported that flash point is not determined because analysis for particle count, viscosity, total acid/base, water content, and metals content provide sufficient information to confirm that the oil does not contain water or contaminants that would permit the onset of aging effects. The applicant stated that STP monitors the percent fuel dilution in the BOP diesel generator lubricating oil. The percent fuel dilution method is used to determine fuel dilution and is also called Fourier transform infrared (FTIR) spectroscopy. The staff reviewed this exception against the corresponding program element in GALL Report AMP XI.M39 and finds it acceptable because fuel contamination is one of the parameters that this method is able to detect during testing. The main difference between the two methods is that FTIR spectroscopy allows for the determination of fuel dilution percentage, whereas flash point testing results are usually recorded as pass or fail or positive or negative.

Enhancement 1. LRA Section B2.1.23 describes an enhancement to the "parameters monitored or inspected" program element. The LRA states that the Lubricating Oil Analysis Program procedures will be enhanced to require analysis for particle count of the lubricating oil for the centrifugal charging pump. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M39 and finds it acceptable because, when it is implemented, it will make the program consistent with the recommendations in GALL Report AMP XI.M39.

Enhancement 2. LRA Section B2.1.23 also describes an enhancement to the "acceptance criteria" program element. The LRA states that the program procedures will be enhanced to require that sample analysis data results, for which no acceptance criteria is specified, be evaluated and trended against baseline data and data from previous samples to determine the acceptability of oil for continued use. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M39 and finds it acceptable.

Summary. Based on its audit of the applicant's Lubricating Oil Analysis Program, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M39. The staff also reviewed the exception associated with the "parameters monitored or inspected" program element, and its justification, and finds that the AMP, with the exception, is adequate to manage the applicable aging effects. In addition, the staff reviewed the enhancements associated with the "parameters monitored or inspected" and "acceptance criteria" program elements and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.23 summarizes operating experience related to the Lubricating Oil Analysis Program. The applicant stated that STP has an OEP that monitors industry issues and assesses them for applicability to its own operation. Furthermore, it was stated that the CAP is used to track, trend, and evaluate plant issues.

The applicant provided the following information regarding operating experience:

> Oil analysis test results for several FWIVs [feedwater isolation valves] indicated high particulate and/or high water content. Corrective actions included changing the filtration unit filters, verifying proper sample techniques, repairing/replacing the reservoir pressure relief valve, and replacing the reservoir oil. Within approximately a year, FWIV oil parameters were back within specification (with one exception, believed to be due to bad seals associated with the [Electro-Hydraulic Control] high efficiency filter unit pump). The frequency of FWIV hydraulic skid filtration unit filter replacement and filtration skid suction strainer cleaning was returned to on-demand.
>
> Oil analysis test results for [power-operated relief valve] PORV 2C indicated high water content. Corrective actions included replacing the oil, cleaning and inspecting the reservoir, replacing the reservoir gaskets, and ensuring the fasteners were tight. Trouble-shooting resulted in the repair of a leaking desiccant receiver and inspection for water. Subsequent test results were satisfactory.
>
> Oil analysis test results for [reactor coolant pumps] RCP 1A and 1B indicated high particulate content. Corrective actions included oil replacement. Subsequent test results were satisfactory.
>
> Oil analysis test results [for the Main Turbine Lube Oil Reservoir] indicated high water content. Corrective actions included processing the oil until the test results were in specification.

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 evaluated and incorporated 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 applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A1.23 provides the UFSAR supplement for the Lubricating Oil Analysis Program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the applicant committed (Commitment No. 18) to ongoing implementation of the existing Lubricating Oil Analysis Program for managing aging of applicable components during the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Lubricating Oil Analysis Program, the staff determines that the program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justification and determines that the AMP, with the exception, is adequate to manage the applicable aging effects. Also, the staff reviewed the enhancements and confirmed that their implementation—through Commitment No. 18 prior to the period of extended operation—will make the AMP adequate to manage the applicable aging effects. 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).

3.0.3.2.20 Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Summary of Technical Information in the Application. LRA Section B2.1.25 describes the existing Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program as consistent, with enhancements, with GALL Report AMP XI.E3, "Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." The applicant stated that the existing program manages localized damage and breakdown of insulation leading to electrical failure of inaccessible medium-voltage cables exposed to adverse localized environments caused by significant moisture (moisture which lasts more than a few days) simultaneously with significant voltage (energized greater than 25 percent of the time) to ensure that inaccessible medium voltage cables not subject to EQ requirements of 10 CFR 50.49 and are within the scope of license renewal are capable of performing their intended function. The applicant also stated that all manholes that contain in-scope non-EQ inaccessible medium-voltage cables are inspected for water collection. The applicant further stated that this inspection and water removal is performed based on actual plant experience. In addition, the applicant stated that all in-scope, non-EQ inaccessible medium voltage cables routed through manholes are tested to provide an indication of the conductor insulation condition. The applicant committed to perform the first test 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 compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.E3.

For the “scope of program,” “preventive actions,” “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” “acceptance criteria,” and “corrective actions” program elements, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The “scope of program,” “preventive actions,” “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” “acceptance criteria,” and “corrective actions” program elements in GALL Report AMP XI.E3 recommend the following actions based on recent plant-specific and industry operating experience:

- delete the “exposure to significant voltage” criterion (defined as subject to system voltage for more than 25 percent of the time)
- include 400 V to 2 kV inaccessible power cables within the scope of the program
- perform at least an annual frequency of inspections for water collection in manholes
- maintain frequency of testing of at least once every 6 years for in-scope inaccessible power cables for degradation of cable insulation
- perform event-driven inspections (e.g., as a result of heavy rain or flood)
- evaluate cable test and manhole inspection results to determine the need for more frequent testing and inspections
- take corrective actions and perform an engineering evaluation when the test or inspection acceptance criteria are not met
- take actions to keep the cable dry and to assess cable degradation

However, during its audit, the staff found that the applicant’s Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program was not consistent with the above criteria. By letter dated August 15, 2011, the staff issued RAI B2.1.25-1 requesting that the applicant respond to the following:

> Explain how South Texas Project will manage the effects of aging on inaccessible low voltage power cables within the scope of license renewal; with consideration of recently identified industry operating experience and plant-specific operating experience. The discussion should include assessment of your Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program description, program elements (i.e., “scope of program,” preventive actions,” parameters monitored/ inspected,” “detection of aging effects,” “monitoring and trending,” “acceptance criteria,” and “corrective actions”), UFSAR summary description as described in GALL Report AMP XI.E3, Revision 2 and applicable license renewal commitment to demonstrate reasonable assurance that the intended functions of inaccessible low voltage power cables subject to adverse localized environments will be maintained consistent with the current licensing basis through the period of extended operation.

In its response dated October 10, 2011, the applicant stated that STP has not experienced any failures of in-scope inaccessible low-voltage power cables due to moisture. The applicant also stated that a review of industry operating experience determined that the industry has had failures of in-scope inaccessible low-voltage power cables due to moisture. Furthermore, the applicant stated that LRA Amendment 2 dated June 16, 2011, and the applicant's RAI response dated October 10, 2011, amended LRA Sections A1.25 and B2.1.25 and LRA Table A4-1, item 20, to include in-scope inaccessible low-voltage power cables (greater than 400 V). The staff reviewed the LRA amendment in conjunction with the RAI response and confirmed that the applicant revised LRA Sections A1.25 and B2.1.25 and LRA Table A4-1, item 20 (Commitment No. 20), to include inaccessible low-voltage power cables (greater than 400 V), consistent with GALL Report AMP XI.E3. In addition, LRA Amendment 2, in conjunction with the RAI response, revises LRA Sections A1.25 and B2.2.25 and LRA Table A4-1 to include the following actions:

- The significant voltage criterion will be deleted.
- The scope of the program will be increased to include in-scope non-EQ inaccessible medium- or low-voltage (greater than 400 V) power cables.
- The inspection frequency of in-scope manholes and trenches for water accumulation will be revised to at least once annually.
- The testing frequency of in-scope inaccessible medium-voltage and low-voltage (greater than 400 V) power cables will be revised to at least once every 6 years.
- Manhole inspection results are evaluated based on actual plant experience with the inspection frequency increased based on experience with water accumulation.
- LRA Section B2.1.25 will be revised to require an engineering evaluation to be performed when the test or inspection criteria are not met. The engineering evaluation will consider the significance of the test results, the operability of the component, the reportability of the event, the extent of the concern, potential root causes for not meeting the test or inspection criteria, the corrective actions required, and the likelihood of recurrence. In addition, an extent of condition is required when an unacceptable condition or situation is identified.

The staff confirmed that an "extent of the concern" (procedure 0PGP03-ZX-002, Revision 40, dated June 6, 2011) performs an evaluation to determine whether the same condition or situation is applicable to other components (e.g., in-scope inaccessible power cables) consistent with GALL Report AMP XI.E3 guidance.

The applicant's LRA revisions—to delete the significant voltage criterion, increase the scope of program to include non-EQ inaccessible medium- or low-voltage (greater than 400 V) power cables, require inspection of manholes and trenches at least once annually, require testing of in-scope cable at least once every 6 years, and increase the inspection frequency based on experience with water accumulation—are also consistent with GALL Report AMP XI.E3.

Although the applicant stated in its response to RAI B2.1.25-1 (item e) that event-driven inspections are performed as an on-demand activity based on actual plant experience, event-driven inspections were not included in LRA Sections B2.1.25, A.1.25, LRA Table A4-1, Commitment No. 20, or Basis Document STP-AMP-B2.1.25 (XI.E3). In a conference call held on November 30, 2011, the staff asked the applicant to explain why event-driven inspections were not included in the LRA. The applicant agreed to supplement the LRA to include event-driven inspections for the applicant's Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. By letter dated December 7, 2011, the applicant revised LRA Sections B2.1.25 and A1.25 and LRA Table A4-1 to state that event-driven inspections of in-scope manholes will be performed as an ongoing demand activity based on actual plant experience. The staff finds the response acceptable because the LRA now includes event-driven inspections consistent with GALL Report AMP XI.E3. The staff's concerns regarding not including event-driven inspections in the LRA are resolved.

The "detection of aging effects" program element in GALL Report AMP XI.E3 recommends that "[f]or power cables exposed to significant moisture, test frequencies are adjusted based on test results (including trending of degradation where applicable) and operating experience." The applicant, in its response to RAI B2.1.25-1, stated that Basis Document STP-AMP-B2.1.25 (XI.E3), "Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements," LRA Section B2.1.25, and LRA Table A4-1, item 20, are revised to include trending of the cable test results based on the type of test performed. However, the change did not indicate whether test frequencies may be increased based on test results or operating experience consistent with GALL Report AMP XI.E3.

By letter dated December 6, 2011, the staff issued RAI B2.1.25-4 requesting that the applicant explain why test frequency adjustment based on test results and operating experience is not included in Basis Document STP-AMP-B2.1.25 (XI.E3), LRA Sections B2.1.25 and A1.25, and LRA Table A4-1, item 20.

By letter dated January 5, 2012, the applicant stated that the LRA was submitted prior to the issuance of the GALL Report, Revision 2, and the adjustment of the test frequency based on test results and operating experience was inadvertently omitted when LRA AMP B2.1.25 was updated to include medium- and low-voltage power cables (greater than 400 V). The applicant further stated that LRA Appendices A1.25 and B2.1.25, Table A4-1, item 20, and LRA Basis Document STP-AMP-B2.1.25 (XI.E3) are revised to address adjusting the test frequency based on test results and operating experience. The staff finds the response acceptable because the LRA now includes adjustment of test frequencies consistent with GALL Report AMP XI.E3. The staff's concern regarding the adjustment of test frequencies based on test results and operating experience is resolved.

The staff finds the applicant's responses acceptable because with the addition of inaccessible low-voltage power cables (greater than 400 V), the revision of inspection and test frequencies, the removal of the significant voltage criterion, the addition of event-driven inspections, and the specification that inspection and test results will be evaluated and adjusted based on inspection and test results and operating experience, the applicant's Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is now consistent with GALL Report AMP XI.E3. The staff's concerns described in RAI B2.1.25-1, RAI B2.1.25-4, and conference call held on November 30, 2011, are resolved.

GALL Report AMP XI.E3 recommends taking periodic actions to prevent inaccessible cables from being exposed to significant moisture, such as identifying and inspecting in-scope accessible cable conduit ends and cable manholes for water collection and draining the water, as needed. However, during its audit, the staff found that the applicant's procedure OPGP04-ZE-0007, "License Renewal Electrical Aging Management," lists in Appendix B, "Manholes Subject to Moisture Intrusion Containing In-Scope Medium Voltage Cables," manholes subject to inspection for water collection that contain in-scope medium voltage cable. It is not clear to the staff whether the Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program includes all in-scope manholes and that in-scope manholes are subject to inspection for water collection consistent with GALL Report AMP XI.E3. By letter dated August 15, 2011, the staff issued RAI B2.1.25-2 requesting that the applicant explain why procedure OPGP0-ZE-0007, Appendix B, appears to limit the in-scope manholes to only manholes previously found subject to water intrusion.

In its response dated October 10, 2011, the applicant stated that Appendix B of STP draft procedure OPGP04-ZE-0007 lists those manholes containing in-scope medium- or low-voltage cables. The applicant further stated that the title for draft procedure OPGP04-ZE-0007, Appendix B, will be revised to read "In-Scope Manholes." Additionally, the applicant stated that the second paragraph of draft procedure OPGP04-ZE-0007, Section 5.2.2, "Scope," will be revised to read, "Appendix B, In-Scope Manholes Lists All Manholes Containing In-Scope Medium or Low Voltage Cables."

The staff finds the applicant's response acceptable because the applicant clarified that draft procedure OPGP04-ZE-0007 does, in fact, list manholes containing in-scope medium or low-voltage cables and is not limited to in-scope manholes previously subjected to water intrusion. The staff's concern described in RAI B2.1.25-2 is resolved.

In its review of procedure OPGP04-ZE-0007, LRA Section B2.1.25, and the applicant's Basis Document STP-AMP-B2.1.25 (XI.E3), "Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements," the staff noted inconsistencies between the guidance in the documents themselves and with the GALL Report concerning corrective actions to remove accumulated water from in-scope manholes. In addition, the staff found that procedure OPGP04-ZE-0007, LRA Section B2.1.25, and Basis Document STP-AMP-B2.1.25 (XI.E3) are also inconsistent with each other and the GALL Report in documenting submerged cables during inspection and the corrective action to be taken (such as initiating a condition report). By letter dated August 15, 2011, the staff issued RAI B2.1.25-3 requesting that the applicant reconcile LRA B2.1.25, Basis Document STP-AMP-B2.1.25 (XI.E3), and procedure OPGP04-ZE-0007 such that consistent inspection activities are used to identify in-scope cable submergence and accumulated water removal, and appropriate corrective actions are taken to keep in-scope cable dry and to assess cable degradation.

In its responses dated October 10, 2011, and December 7, 2011, the applicant stated that revisions will be made to provide consistent guidance with respect to removal of accumulated water from in-scope manholes and documentation of submerged cables and corrective action taken. The applicant also included additional revisions to LRA Section B2.1.25, LRA Table A4-1, item 20, and Basis Document STP-AMP-B2.1.25 (XI.E3) and associated procedures. For the program element, "preventive actions," procedures will also be revised to include the following:

- inspection of in-scope manholes and trenches based on plant-specific operating experience conducted at least annually
- event-driven inspections of in-scope manholes performed as an on-demand activity based on actual plant experience
- direct observation that cables are not wetted or submerged
- removal of collected water and verification of sump pump operability
- initiation of corrective action if wetted cables or inoperable sump pumps are found
- inspection of the cables/splices and cable support structure whenever wetted cables are found
- corrective actions taken to keep cables dry

In addition, the applicant stated that the following additional revisions will be made to plant procedures:

- For manholes equipped with solar-powered sump pump system, the inspection shall include:
  - direct observation that cables are not wetted or submerged
  - removal of collected water
  - verification of solar-powered sump pump operability

- If wetted cables are found, the following will be done:
  - initiate a condition report
  - remove collected water and take corrective action to keep cables dry
  - inspect cables/splices for surface anomalies
  - inspect support structures for corrosion
  - increase the frequency of next inspection based on experience with water accumulation

- If any of the manhole sump pumps are found to be not operating, the following will be done:
  - repair inoperable sump pumps
  - initiate a condition report

- For manholes not equipped with solar-powered sump pumps and trenches, the inspection will include
  - direct observation that cables are not wetted or submerged
  - removal of collected water

- If wetted cables are found, the following will be done:
  - initiate a condition report
  - remove collected water and take corrective action to keep cables dry
  - inspect cables/splices for surface anomalies
  - inspect support structures for corrosion
  - increase the frequency of the next inspection based on experience with water accumulation

The staff finds the applicant's response acceptable because the applicant revised LRA Section B2.1.25, LRA Table A4-1, item 20, Basis Document STP-AMP-B2.1.25 (XI.E3), and procedures consistent with GALL Report AMP XI.E3 such that the inspection activities are consistent with respect to inspection activities used to identify in-scope cable submergence, accumulated water removal, and corrective actions. The staff's concern described in RAI B2.1.25-3 is resolved.

The staff also reviewed the portions of the "scope of program," "preventive actions," "parameters monitored or inspected," "acceptance criteria," and "corrective actions" program elements associated with enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B2.1.25 states an enhancement to the "scope of program" program element. In this enhancement, the applicant stated that procedures will be enhanced to identify the cable and manholes that are within the scope of the Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.E3 and finds it inconsistent with GALL Report AMP XI.E3. LRA Section B2.1.25 includes only inaccessible medium voltage cables while GALL Report AMP XI.E3 guidance includes low-voltage inaccessible power cables (400 V to 2 kV) as well as inaccessible medium voltage cables (2 kV to 35 kV) in-scope of GALL Report AMP XI.E3. Inaccessible low-voltage power cable service voltages (400 V to 2 kV) not included in the applicant's Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program are addressed in RAI B.2.1.25-1. In its response dated October 10, 2011, the applicant stated that LRA Sections A1.25 and B2.1.25 and LRA Table A4-1, item 20, were amended in the applicant's LRA, Amendment 2, dated June 16, 2011, to include in-scope inaccessible low-voltage power cables (greater than 400 V).

The staff finds the applicant's response acceptable because with the inclusion of inaccessible low-voltage cables (greater than 400 V), the applicant's program is now consistent with GALL Report AMP XI.E3. The staff's concern regarding low-voltage inaccessible power cable described in RAI B2.1.25-1 is resolved.

With the applicant's revised scope of the program, the staff finds the enhancement acceptable because it is consistent with the scope of GALL Report AMP XI.E3. This enhancement is identified as part of Commitment No. 20 to be implemented prior to the period of extended operation.

Enhancement 2. LRA Section B2.1.25 states an enhancement to the "preventive actions" program element. In this enhancement, the applicant stated that procedures will be enhanced to require that the cable manholes be inspected for water collection based on plant experience. The enhancement also requires that the inspection frequencies for all in-scope manholes be at least once every 2 years. The enhancement requires any manholes containing water to be pumped dry, the source of the water to be investigated, and the inspection frequency to be increased based on past experience. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.E3 and finds it inconsistent with those in GALL Report AMP XI.E3. The manhole inspection frequency of at least once every 2 years specified for the applicant's program is inconsistent with the GALL Report AMP XI.E3 inspection frequency of at least annually. The inconsistency in manhole inspection frequency is addressed by RAI 2.1.25-1. In its response dated October 10, 2011, the applicant stated that LRA Section B2.1.25 will be revised to include inspection of manholes and trenches based on plant-specific operating experience with inspections being conducted at least annually.

The staff finds the applicant's response acceptable because the applicant revised LRA Section B2.1.25 program element "preventive actions" to include a manhole and trench inspection frequency of at least annually, consistent with GALL Report AMP XI.E3. The staff's concern regarding the inconsistency in manhole inspection frequencies described in RAI B2.1.25-1 is resolved.

With the applicant's "preventive actions" program element including a revised manhole and trench inspection frequency of at least annually, the staff finds the enhancement acceptable because it is consistent with GALL Report AMP XI.E3. This enhancement is identified as part of Commitment No. 20 to be implemented prior to the period of extended operation.

Enhancement 3. LRA Section B2.1.25 states an enhancement to the “parameters monitored or inspected” program element. In this enhancement, the applicant stated procedures will be enhanced to require that all in-scope non-EQ inaccessible medium voltage cables exposed to significant moisture simultaneously with significant voltage be tested to provide an indication of the conductor insulation condition. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.E3 and finds it inconsistent with those in GALL Report AMP XI.E3, which do not include the significant voltage criterion. The significant voltage criterion limits the in-scope inaccessible medium voltage power cables to inaccessible medium voltage cable energized more than 25 percent of the time. The inclusion of the significant voltage criterion in the applicant’s Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is addressed by RAI 2.1.25-1. In its response dated October 10, 2011, the applicant stated that LRA Section B2.1.25 will be revised to delete the significant voltage criterion.

The staff finds the applicant’s response acceptable because the applicant revised the program element “parameters monitored or inspected” to eliminate the significant voltage criterion, consistent with GALL Report AMP XI.E3. The staff’s concern regarding the inclusion of the significant voltage criterion described in RAI B2.1.25-1 is resolved.

With the elimination of significant voltage as a criterion from the applicant’s Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, the staff finds the enhancement acceptable because the “parameters monitored or inspected” program element is now consistent with GALL Report AMP XI.E3. This enhancement is identified as part of Commitment No. 20 to be implemented prior to the period of extended operation.

Enhancement 4. LRA Section B2.1.25 states an enhancement to the “acceptance criteria” program element. In this enhancement, the applicant stated procedures will be enhanced to require acceptance criteria be defined prior to each test for the specific type of test performed and the specific cable tested. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.E3 and finds it inconsistent with GALL Report AMP XI.E3 acceptance criteria program element guidance for in-scope cable testing because the applicant’s enhancement does not address manhole inspection acceptance criteria as part of the program element. The inclusion of manhole inspection results in the applicant’s Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is addressed by RAI B2.1.25-1. In its response dated October 10, 2011, the applicant stated that LRA Section B2.1.25 will be revised to include the addition of inspection acceptance criteria for electrical manholes and trenches, cables/splices, and cable support structures.

The staff finds the applicant’s response acceptable because the applicant revised LRA Section B2.1.25 program element, “acceptance criteria,” to add inspection acceptance criteria for the inspection of electrical manholes and trenches—including cables/splices—and cable support structures consistent with GALL Report AMP XI.E3. The staff’s concern regarding the inclusion of the manhole inspection acceptance criteria described in RAI B2.1.25-1 is resolved.

With the inclusion of electrical manhole and trench inspection acceptance criteria, the staff finds the enhancement acceptable because it is consistent with GALL Report AMP XI.E3. This enhancement is identified as part of Commitment No. 20 to be implemented prior to the period of extended operation.

Enhancement 5. LRA Section B2.1.25 states an enhancement to the “corrective actions” program element. In this enhancement, the applicant stated that procedures will be enhanced to require an engineering evaluation that considers the age and operating environment of the cable be performed when the test acceptance criteria are not met. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.E3 and finds it inconsistent with GALL Report AMP XI.E3. The staff noted that the applicant’s CAP did not include corrective actions when inspection acceptance criteria are not met as part of the Corrective Actions Program element. The inclusion of corrective actions into the applicant’s Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is addressed by RAI B2.1.25-1. In its response dated October 10, 2011, the applicant stated that it revised (by LRA Amendment 2) its AMP to perform an engineering evaluation—that considers the age and operating environment of the cable—when test or inspection acceptance criteria are not met. The applicant also stated that the engineering evaluation will consider the significance of test or inspection results, the operability of the component, the reportability of the event, the extent of the concern, the potential root causes for not meeting the test or inspection acceptance criteria, the corrective actions required, and the likelihood of recurrence.

The staff finds the applicant’s response acceptable because the applicant revised the “corrective actions” program element to add corrective actions consistent with GALL Report AMP XI.E3. The staff’s concern regarding the inclusion of acceptance criteria described in RAI B2.1.25-1 is resolved.

With the inclusion of inspection corrective actions, the staff finds the enhancement acceptable because it is consistent with GALL Report AMP XI.E3. This enhancement is identified as part of Commitment No. 20 to be implemented prior to the period of extended operation.

In its responses to RAI B2.1.25-1, RAI B2.1.25-4, and letter dated December 7, 2011, the applicant included an additional enhancement to include the following LRA Section B2.1.25 program element additions.

- Parameters Monitored or Inspected
  - Inspection of the in-scope manholes and trenches for water accumulation is based on plant experience with water accumulation.
  - The inspection frequency is to be at least annually.
  - Testing of in-scope inaccessible medium- and low-voltage (greater than 400 V) power cables exposed to significant moisture is conducted using a test capable of detecting reduced insulation resistance.
- Detection of Aging Effects
  - In-scope inaccessible medium- and low-voltage (greater than 400 V) power cables exposed to significant moisture are tested at least every 6 years with the first test being completed prior to the period of extended operation.
  - Testing of in-scope inaccessible medium- and low-voltage (greater than 400 V) power cables exposed to significant moisture is conducted using a test capable of detecting reduced insulation resistance.

- Monitoring and Trending
  - Procedures will be enhanced to require inspection and test results that can be trended to provide additional information on the rate of cable degradation.

- Acceptance Criteria
  - The acceptance criterion for manhole and trench cables/splices and support structures is that they are not submerged or immersed in water.

The acceptance criteria for cable testing will be defined prior to each test for the specific type of test performed and the specific cable tested. The staff finds the applicant's enhancement acceptable because the applicant revised LRA Section B2.1.25 program elements "parameters monitored or Inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" to include additional criteria consistent with the GALL Report AMP XI.E3.

With the inclusion of additional program element criteria, the staff finds the enhancement acceptable because it is consistent with GALL Report AMP XI.E3. This enhancement is included as part of Commitment No. 20 to be implemented prior to the period of extended operation.

Summary. Based on its audit, and review of the applicant's responses to RAIs B2.1.25-1, B2.1.25-2, B2.1.25-3, and B2.1.25-4, and the applicant's letter dated December 7, 2011, concerning the applicant's Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, the staff finds that the program elements for which the applicant claimed consistency with GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.E3.

In addition, the staff reviewed the enhancements associated with the "scope of program," "preventive actions," "parameters monitored or inspected," monitoring and trending," "acceptance criteria," and "corrective actions" program elements and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.25 summarizes operating experience related to the Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. The applicant stated that site-specific operating experience has shown that STP has not experienced a failure of any in-scope medium voltage cables. The applicant did identify plant operating experience where water leaked into the Unit 2 cable vault and electrical auxiliary building battery rooms. The applicant identified the source of water as a series of manholes leading into the rooms. The applicant stated that the cause of the water intrusion was damaged manhole covers and a sump pump cover that was open for an extended period of time. The applicant also stated that STP has also experienced recurring groundwater intrusion in some manholes. The applicant further stated that solar-powered sump pumps have been installed in the affected manholes and have been effective in preventing cable exposure to significant moisture. In addition, the applicant stated that, as additional industry operating experience and applicable plant-specific operating experience becomes available, the operating experience will be evaluated and appropriately incorporated into the program through the STP "corrective action" and "operating experience" program elements.

During the audit, the staff, with regional support, walked down four nonsafety-related manholes and one safety-related manhole. Two nonsafety-related manholes were located in the switchyard area. Operating history indicated that both manholes had experienced flooding in the past. Applicant corrective actions included increasing the sump pump capacity for one manhole by replacing the solar-powered pumps with a pair of higher capacity electric sump pumps. The manhole covers were also sealed to prevent surface water intrusion into the manhole. The staff confirmed during the walkdown the additional sump pumps and the installation of manhole cover seals and inspection ports.

The staff also walked down two additional nonsafety-related manholes including a manhole containing in-scope cables for station blackout. Both manholes were found dry during the walkdown. Additionally, the staff also inspected one safety-related manhole, which required the manhole seal to be opened. The staff observed water to be present in the manhole sump only. The staff has also performed inspections of manholes using Inspection Procedure 7111.06, “Flood Protection Measures,” with no findings of significance identified in the manhole samples selected.

The staff also reviewed recent work orders (2009–2011) for both safety- and nonsafety-related in-scope manholes. No cable submergence was noted in the review. In the applicant’s response to GL 2007-01, “Inaccessible or Underground Power Cable Failures That Disable Accident Mitigation Systems or Cause Plant Transients,” dated February 7, 2007, the applicant stated that STP has experienced no inaccessible or underground power failure cable failures within the scope of the GL. The applicant did indicate that the 480 V motor control center cable feeds (trains A, B, and C) for ECW system components had been replaced based on test results (low insulation resistance).

The staff also reviewed applicable condition reports, including one written for water intrusion during safety-related manhole preventive maintenance. The applicant found one manhole where the as-found water level did not meet the acceptance criteria for water intrusion. The applicant pumped out the vault and sealed the manhole cover. The applicant confirmed during the inspection that cables were not submerged through visual inspection. The root cause of the water intrusion was determined to be surface water entering through unsealed manhole covers. The staff reviewed subsequent work orders performed on May 1, 2008, May 4, 2009, May 5, 2010, and May 19, 2011, and noted that the water level for this manhole met the acceptance criteria.

Operating history reviewed by the staff indicated that manhole water intrusion and subsequent submergence of low- and medium-voltage cable was identified by the applicant as a potential problem for safety- and nonsafety-related manholes. Corrective actions have included sealing manhole covers, raising manhole covers to limit surface water intrusion, installing sump pumps in nonsafety-related manholes, adding inspection ports, and initiating periodic preventive maintenance work orders (PMWOs) to inspect safety- and nonsafety-related manholes and sump pumps.

During the audit, the staff noted that for safety-related manholes, the PMWO acceptance criteria for manhole water intrusion may allow an as-left water level just below the cable elevation. It was not clear to the staff that the acceptance criterion was developed such that sufficient margin would be maintained over the next surveillance interval to prevent cable exposure to significant moisture (no submerged cable). In addition, manhole PMWOs do not consistently include steps to document cable submergence or require a condition record be generated. Based on this information, the applicant initiated condition record CR 11-100096, which requests all manhole preventive maintenance tasks be evaluated for consistent expectations including requirements for recording water level with specific acceptance criteria for “as-found water level” and when manholes require pumping. In addition, the condition record is to ensure that acceptance criteria have sufficient margin to ensure cables are not subjected to significant moisture and that specific work instructions steps specify when to generate a condition record based upon the "as found condition" including any requisite cable evaluation.

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 evaluated and incorporated 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 applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A1.25 provides the UFSAR supplement for the Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program.

The staff reviewed this UFSAR supplement description of the program against the recommended description for this type of program, as described in SRP-LR Table 3.0-1, and noted that GALL Report AMP XI.E3 recommends the following based on recent plant-specific and industry operating experience:

- deletion of the "exposure to significant voltage" criterion (defined as subject to system voltage for more than 25 percent of the time)
- scope of program to include 400 V to 2 kV inaccessible power cables
- at least an annual frequency of inspections for water collection in manholes
- frequency of testing of at least once every 6 years for in-scope inaccessible power cables for degradation of cable insulation
- event-driven inspections (e.g., as a result of heavy rain or flood)
- evaluation of cable test results and manhole inspection results to determine the need for more frequent testing and inspections

The licensing basis for this program 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 August 15, 2011, the staff issued RAI B2.1.25-1 requesting that the applicant explain why the above criteria are not referenced in the applicant's UFSAR Section A1.25, "Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," supplement, consistent with SRP-LR Table 3.0-1 and GALL Report AMP XI.E3. In its response dated October 10, 2011, the applicant stated that LRA Section A.1.25 was revised in LRA Amendment 2 to:

- delete the significant voltage criterion
- include in-scope non-EQ inaccessible medium- or low-voltage (greater than 400 V) power cable
- revise the manhole inspection to be performed based on actual plant experience with an inspection frequency of at least annually
- revise the testing frequency of in-scope inaccessible medium- and low-voltage (greater than 400 V) power cables to at least once every 6 years

The applicant further stated in its letter dated December 7, 2011, that event-driven inspections are performed as an on-demand activity based on actual plant experience. Finally, the applicant stated in its response to RAI B2.1.25-4, dated January 5, 2012, that testing frequencies are adjusted based on test results and operating experience.

The staff finds the applicant's response acceptable because the applicant revised LRA Section A1.25 to include inaccessible low-voltage cable (greater than 400 V), inspection, test, and acceptance criteria including criteria for manhole and trench inspections consistent with the SRP-LR Table 3.0-1 and GALL Report AMP XI.E3. Therefore, the UFSAR supplement for the Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is consistent with the corresponding program description in SRP-LR Table 3.0-1. The staff's concerns described in RAI B2.1.25-1, RAI B2.1.25-4, and conference call held on November 30, 2011, are resolved.

The staff also noted that the applicant committed (Commitment No. 20) to enhance the existing Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program for managing aging of applicable components prior to entering the period of extended operation.

The staff finds that the information in the UFSAR supplement, as amended by letters dated October 10, 2011; December 7, 2011; and January 5, 2012, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation, through Commitment No. 20 prior to the period of extended operation, will make the AMP adequate to manage the applicable aging effects. 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).

3.0.3.2.21 Metal Enclosed Bus

Summary of Technical Information in the Application. LRA Section B2.1.26 describes the existing Metal Enclosed Bus (MEB) Program as consistent, with an enhancement, with GALL Report AMP XI.E4, "Metal Enclosed Bus." The LRA states that the non-segregated phase portion of the program manages loosening of bolted connections, embrittlement, cracking, melting, swelling, discoloration of insulation, electrical failure, loss of dielectric strength leading to reduced insulation resistance (IR), loss of material of bus enclosure assemblies, hardening and loss of strength of boots and gaskets, and cracking of internal bus supports. A sample of the non-segregated phase bus accessible bolted connections will be inspected for loose connections using thermography. Internal portions of isolated phase buses are visually inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The bus insulators are inspected for signs of embrittlement, cracking, melting, swelling, hardening, or discoloration, which may indicate overheating or aging degradation. The internal bus supports are inspected for structural integrity and signs of cracks. The bus enclosure assemblies are inspected for loss of material due to corrosion and hardening of boots and gaskets.

Staff Evaluation: During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared elements one through six of the applicant's program to the corresponding elements of GALL Report AMP XI.E4. For the "detection of aging effect" program element, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

The "detection of aging effects" program element in GALL Report AMP XI.E4, Revision 2, recommends that a sample of accessible bolted connections is inspected for increased resistance of connection by using thermography or by measuring connection resistance using a micro-ohmmeter. It also recommends that 20 percent of the population with a maximum sample of 25 constitutes a representative sample size. Otherwise, a technical justification of the methodology and sample size used for selecting components should be included as part of the AMP's site documentation. It further recommends that if an unacceptable condition or situation is identified in the selected sample, a determination is made as to whether the same condition or situation is applicable to other connections not tested. However, during its audit, the staff found that in the applicant's aging program evaluation report for MEB B2.1.26, "STP-AMP-B2.1.26," under the same program element states that a sample of non-segregated phase bus accessible bolted connections in each bus section shall be inspected for evidence of overheating using thermography. The applicant has not identified the sample size of bolted connections or developed the technical basis for selecting samples of bolted connections in each MEB section. By letter dated August 15, 2011, the staff issued RAI B2.1.26-1 requesting that the applicant explain how the sample selection approach in AMP B2.1.26 is consistent with that in GALL Report AMP XI.E4, Revision 2. In a letter dated October 10, 2011, the applicant responded that the sample will be 20 percent of the population with a maximum sample of 25 connections. The sample will be selected to include at least 1 connection in each section of the non-segregated phase bus, up to a maximum of 25 connections, and will include sections that are exposed to plant indoor air and atmosphere or weather (outdoors). The staff finds the applicant's response acceptable because the sample selection criterion is consistent with that in GALL Report AMP XI.E4. The staff's concern described in RAI B2.1.26-1 is resolved.

The "detection of aging effects" program element in GALL Report AMP XI.E4 recommends that a sample of accessible bolted connections will be checked for loose connections. However, during its audit, the staff found that the applicant's basis document, STP-AMP-B2.1.26, Revision 2, only requires a sample of the non-segregated phase bus bolted connections to be inspected, and the applicant was silent on the inspection of in-scope iso-phase bus connections. The iso-phase bus connections could be loose due to ohmic heating and could cause iso-phase bus failure. By letter dated August 15, 2011, the staff issued RAI B2.1.26-3 requesting that the applicant explain why iso-phase bus connections are not included in AMP B2.1.26. In a letter dated October 10, 2011, the applicant stated that the sections of the iso-phase bus are welded joints and do not contain bolted connections. The applicant further stated that there are bolted connections at the main transformers, the unit auxiliary transformer, and the main generator breaker. However, these connection points are managed as part of transformer or breaker active component maintenance. The staff finds the applicant's response acceptable because the in-scope iso-phase bus connections are at the active components, and these connections are maintained as part of periodic active component maintenance. There are no bolted connections between buses, and all of the bus sections are welded. Based on this information, the staff determined that bolted connections for iso-phase bus are not required to be included in the Metal Enclosed Bus Program. The staff's concern described in RAI B2.1.26-3 is resolved.

In the STP basis document, STP-AMP-B2.1.26, Revision 2, the applicant stated that a sample of the MEB accessible bolted connections in each bus section shall be inspected using thermography for evidence of overheating. The applicant also stated that acceptable criteria will be based on a temperature rise above the reference temperature, and the reference temperature will be the ambient temperature or the baseline temperature data from the same type of connections being tested. The applicant further stated that the inspections are performed on all accessible bus sections while the bus is energized. The staff noted that, in general, inspection windows are installed on the MEB for thermography inspections. The MEB cover may mask the heat created by loosening of bus connections and the temperature differences between bus connections, which may not be detected, if windows are not installed on MEBs. By letter dated August 15, 2011, the staff issued RAI B2.1.26-2 requesting that the applicant explain how the MEB connection inspections at STP are effective in detecting loosening of bus connections using external thermography measurements. In its response dated October 10, 2011, the applicant stated that at STP, the non-segregated phase bus bolted connections are covered with insulation material. Instead of thermography, a sample of the in-scope non-segregated phase bus accessible bolted connections covered by insulation material will be visually inspected to detect surface anomalies, such as embrittlement, cracking, melting, discoloration, swelling, or surface contamination. The staff finds the applicant's response acceptable because visual inspection of insulation materials for surface anomalies will detect the heat created by high resistance of the bus connections. The visual inspection of insulation materials to detect heat created by high resistance of bolted connections is consistent with that in GALL Report AMP XI.E4. The staff's concern described in RAI B2.1.26-2 is resolved.

The staff also reviewed the portions of the "scope of program," "preventive actions," "detection of aging effects," "acceptance criteria," and "corrective actions" program elements associated with the enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this enhancement follows.

<u>*Enhancement*</u>. LRA Section B2.1.26 states an enhancement to the "scope of program," "preventive actions," "detection of aging effects," "acceptance criteria," and "corrective actions" program elements. In this enhancement, the applicant stated that the existing bus inspection activities for inspection and testing of the MEBs will be proceduralized to identify license renewal scope, specific bus inspection requirements, and aging effects to be inspected for frequencies of inspections, acceptance criteria, and actions to be taken when acceptance criteria are not met. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.E4 and finds it acceptable because, when implemented, it will make the program consistent with GALL Report AMP XI.E4.

<u>*Summary*</u>. Based on its audit, and review of the applicant's responses to RAIs B2.1.26-1, B2.1.26-2, and B2.1.26-3, the staff finds that the program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding

program elements of GALL Report AMP XI.E4. In addition, the staff reviewed the enhancement associated with the “scope of program,” “preventive actions,” “detection of aging effects,” “acceptance criteria,” and “corrective actions” program elements and finds that, when implemented, it will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.26 summarizes operating experience related to the Metal Enclosed Bus Program. The applicant stated that a review of plant operating experience has determined that there has been no aging-related degradation that resulted in the loss of intended function of the MEBs. The iso-phase bus and sections of the MEBs are inspected every outage, and the non-segregated bus is inspected every third outage. The applicant also stated that thermography is performed on the non-segregated bus at the switchgear once a year. The inspection results for the MEB during the last 10 years have revealed only one instance of insulation that required rework and one instance where repairs to cracked Noryl sleeving have been made. The applicant further stated that no occurrences of corrosion, loss of material, hardening, foreign debris, excessive dust buildup, water intrusion, or overheating have been found.

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 evaluated and incorporated operating experience related to this program.

The staff reviewed a condition report (CR 04-12979) relating to Noryl cracking on a horizontal section of non-segregated bus section. The Noryl sleeve covering part of the B-phase bus was split (approximately 3 inches long) close to a bus support. The copper bus could be observed through the split. The applicant evaluated this CR in 2004 and concluded that insulation of the bus was not required if the separation distance is greater than 7 inches at the 15 kV voltage level and the crack was acceptable and no repair was needed. During the onsite audit, the staff questioned the applicant evaluation in light of industry operating experience with bus failures due to cracked Noryl insulation. The staff requested that the applicant explain why no action is taken to address the cracked Noryl insulation in the CR. In response to the staff request, the applicant indicated that the cracked insulation was resolved. The applicant provided a PMWO that clearly indicated that the cracked Noryl was replaced or repaired. The applicant also provided a PMWO that requires replacing cracked or defective Noryl.

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 applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A1.26 provides the UFSAR supplement for the Metal Enclosed Bus Program.

The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the applicant committed (Commitment No. 21) to enhance the existing Metal Enclosed Bus Program for managing aging of applicable components prior to entering the period of extended operation.

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Metal Enclosed Bus Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancement and confirmed that its implementation through Commitment No. 21 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. 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).

3.0.3.2.22 ASME Section XI, Subsection IWE

Summary of Technical Information in the Application. LRA Section B2.1.27 describes the existing ASME Section XI, Subsection IWE Program as consistent, with exceptions and an enhancement, with GALL Report AMP XI.S1, "ASME Section XI, Subsection IWE." The LRA states that the AMP manages cracking, loss of material, and loss of sealing of the containment steel liner plate and its integral attachments. The LRA further states that these aging effects are managed primarily through visual inspections augmented with surface and volumetric examinations, as required. The LRA also states that the current program complies with the 2004 edition of ASME Code Section XI, Subsection IWE.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.S1.

For the "preventive actions" and "detection of aging effects" program elements, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

The "preventive actions" program element in GALL Report AMP XI.S1 recommends following recommendations discussed in Section 2 of the Research Council on Structural Connections (RCSC) "Specification for Structural Joints Using ASTM A325 or A490 Bolts," if ASTM A325, ASTM F1852, or ASTM A490 bolts are used. During its audit, the staff confirmed that appropriate visual inspections are conducted on structural bolts; however, it found that the applicant's ASME Section XI, Subsection IWE Program does not discuss the GALL Report recommendations for ASTM A325, ASTM F1852, or ASTM A490 bolts and whether they are followed. Therefore, by letter dated August 15, 2011, the staff issued RAI B2.1.32-1 requesting that the applicant explain how the preventive actions discussed in Section 2 of "Specification for Structural Joints Using ASTM A325 or A490 Bolts" are addressed, or why they are unnecessary.

In its response dated October 10, 2011, the applicant stated that plant procedures require that "only new bolts, nuts, and washers shall be used in bolted connections. Bolts, nuts, and washers shall be in good condition and not corroded, damaged, or dirty." The applicant further stated that plant procedures will be enhanced to include the preventive actions recommended in Section 2 of the RCSC "Specification for Structural Joints Using ASTM A325 or A490 Bolts" for ASTM A325, ASTM F1852, or ASTM A490 bolts.

The staff finds the applicant's response acceptable because the applicant committed to enhance plant procedures to specify the preventive actions for storage, protection, and lubricants, recommended in Section 2 of the RCSC publication, "Specification for Structural Joints Using ASTM A325 or A490 Bolts," for ASTM A325, ASTM F1852, or ASTM A490 bolts, in accordance with the guidance in the GALL Report (Commitment No. 35). The staff's concern described in RAI B2.1.32-1 is resolved. Additional discussion of the applicant's use of high-strength structural bolts and whether appropriate surface or volumetric examinations are being conducted on the high-strength bolts is included in the staff's review of the applicant's Bolting Integrity Program (SER Section 3.0.3.2.5). In a conference call held on January 18, 2012, the staff confirmed that there are no high-strength structural bolts greater than 1-inch diameter within the scope of the ASME Section XI, Subsection IWE Program.

The "detection of aging effects" program element in GALL Report AMP XI.S1 recommends surface examinations to detect cracking for stainless steel penetration sleeves, dissimilar metal welds, bellows, and steel components that are subject to cyclic loading but have no CLB fatigue analysis. However, during its audit, the staff found that the applicant's LRA states that all containment penetrations whose design is supported by a cyclic load analysis are addressed as a TLAA, but it does not state whether there are containment penetrations that are subject to cyclic loads that are not covered by the analysis. Therefore, by letter dated August 15, 2011, the staff issued RAI B2.1.27-1 requesting that the applicant identify any containment stainless steel penetration sleeves, dissimilar metal welds, bellows, or steel components that are subject to cyclic loading but have no CLB fatigue analysis. If components meeting these criteria exist, the applicant should explain how they are monitored for cracking, and if surface examinations are not used, the applicant should explain why they are unnecessary.

In its response dated October 10, 2011, the applicant stated that the specification for containment penetrations identifies and requires a fatigue analysis for all penetrations experiencing significant transients. Review of the stress reports of containment penetrations did not reveal any other containment penetrations that would be subject to fatigue that are not included in LRA Section 4.6.2. The applicant further stated that, based on this review, there are no containment stainless steel penetration sleeves, dissimilar metal welds, bellows, or steel components subject to cyclic loading that do not have a CLB fatigue analysis.

The staff reviewed the UFSAR Section 3.8.2 and LRA Section 4.6.2 and confirmed that penetrations exposed to significant cyclic loading are subject to a TLAA and reviewed in LRA Section 4.6.2. Therefore, the staff finds the applicant's response acceptable because the applicant conducted a review and concluded that there are no containment stainless steel penetration sleeves, dissimilar metal welds, bellows, or steel components subject to cyclic loading that do not have a CLB fatigue analysis. Since there is a fatigue analysis for all containment penetrations subject to cyclic loading, the staff's concern described in RAI B2.1.27-1 is resolved.

The staff also reviewed the portions of the "scope of program," "parameters monitored or inspected," "monitoring and trending," "acceptance criteria," "corrective actions," and "confirmation process" program elements associated with exceptions to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these exceptions follows.

Exception 1. LRA Section B2.1.27 states an exception to the "scope of program" program element. In this exception, the applicant stated that the GALL Report, Revision 1, specifies that ASME Code Section XI, Subsection IWE inspections include pressure-retaining seals and gaskets. The applicant further stated that these components are not addressed by the 2004 edition of the ASME Code Section XI, Subsection IWE, which is the edition currently in place per 10 CFR 50.55a. The staff reviewed this exception against the corresponding program elements in GALL Report AMP XI.S1. The staff noted that using the requirements of the 2004 edition of the ASME Code is the appropriate approach and is captured in the GALL Report, Revision 2, which states that "except where noted and augmented in the GALL Report, the following ASME [Code] Section XI editions and addenda are acceptable and should be treated as consistent with the GALL Report: (1) from the 1995 edition to the 2004 edition, as modified and limited in 10 CFR 50.55a." The staff reviewed 10 CFR 50.55a and the GALL Report AMP and confirmed that no additional requirements or recommendations are made regarding the scope of the IWE Program and pressure-retaining seals and gaskets. Therefore, the staff finds the exception acceptable because the applicant is implementing an NRC-approved edition of the ASME Code, per the guidance in 10 CFR 50.55a and the GALL Report.

Exception 2. LRA Section B2.1.27 states an exception to the "parameters monitored or inspected" program element. In this exception, the applicant stated that the GALL Report, Revision 1, states that Table IWE-2500-1 specifies seven categories for examination. The applicant further stated that the 2004 edition of the ASME Code Section XI, Subsection IWE does not specify seven examination categories. The staff reviewed this exception against the corresponding program element(s) in GALL Report AMP XI.S1. The staff noted that using the requirements of the 2004 edition of the ASME Code is the appropriate approach and is captured in the GALL Report, Revision 2, which states that "except where noted and augmented in the GALL Report, the following ASME [Code] Section XI editions and addenda are acceptable and should be treated as consistent with the GALL Report: (1) from the 1995 edition to the 2004 edition, as modified and limited in 10 CFR 50.55a." The staff reviewed 10 CFR 50.55a and the GALL Report AMP and confirmed that the seven examination categories are no longer required and that the applicant is implementing the appropriate examination categories. Therefore, the staff finds the exception acceptable because the applicant is implementing an NRC-approved edition of the ASME Code, per the guidance in 10 CFR 50.55a and the GALL Report.

Exception 3. LRA Section B2.1.27 states an exception to the "monitoring and trending" program element. In this exception, the applicant stated that the GALL Report, Revision 1, recommends areas identified for augmented examination due to flaws or degradation be reexamined for three consecutive inspection periods and remain essentially unchanged. The applicant further stated that the 2004 edition of ASME Code Section XI, Subsection IWE only requires areas identified for augmented examination remain unchanged for the next inspection period. The staff reviewed this exception against the corresponding program element(s) in GALL Report AMP XI.S1. The staff noted that using the requirements of the 2004 edition of the ASME Code is the appropriate approach and is captured in the GALL Report, Revision 2, which states that "except where noted and augmented in the GALL Report, the following ASME [Code] Section XI editions and addenda are acceptable and should be treated as consistent with the GALL Report: (1) from the 1995 edition to the 2004 edition, as modified and limited in

10 CFR 50.55a." The staff reviewed 10 CFR 50.55a and the GALL Report AMP and confirmed that three consecutive inspection periods are no longer required for augmented inspections. Therefore, the staff finds the exception acceptable because the applicant is implementing an NRC-approved edition of the ASME Code, per the guidance in 10 CFR 50.55a and the GALL Report.

Exception 4. LRA Section B2.1.27 states an exception to the "acceptance criteria," "corrective actions," and "confirmation process" program elements. In this exception, the applicant stated that Table IWE-3410-1, which is referenced in the GALL Report, Revision 1, lists the acceptance criteria for the IWE Program. The applicant further stated that Table IWE-3410-1 was deleted, and in the 2004 edition of the ASME Code Section XI, Subsection IWE Code, the acceptance standards are given in Section IWE-3500. The staff reviewed this exception against the corresponding program element(s) in GALL Report AMP XI.S1. The staff noted that using the requirements of the 2004 edition of the ASME Code is the appropriate approach and is captured in the GALL Report, Revision 2, which states that "except where noted and augmented in the GALL Report, the following ASME [Code] Section XI editions and addenda are acceptable and should be treated as consistent with the GALL Report: (1) from the 1995 edition to the 2004 edition, as modified and limited in 10 CFR 50.55a." The staff reviewed 10 CFR 50.55a and the GALL Report AMP and confirmed that the applicant is implementing the appropriate acceptance criteria, as listed in the IWE-3500. Therefore, the staff finds the exception acceptable because the applicant is implementing an NRC-approved edition of the ASME Code, per the guidance in 10 CFR 50.55a and the GALL Report.

Enhancement. LRA Section B2.1.27 was amended by the applicant's letter dated August 15, 2011, which introduced an enhancement to the "preventive actions" program element. As discussed above, in this enhancement, the applicant stated that plant procedures require that "only new bolts, nuts, and washers shall be used in bolted connections. Bolts, nuts, and washers shall be in good condition and not corroded, damaged, or dirty." The applicant further stated that plant procedures will be enhanced to include the preventive actions recommended in Section 2 of the RCSC "Specification for Structural Joints Using ASTM A325 or A490 Bolts" for ASTM A325, ASTM F1852, or ASTM A490 bolts. The staff finds the applicant's response acceptable because the applicant committed to enhance plant procedures to specify the preventive actions for storage, protection, and lubricants, recommended in Section 2 of the RCSC publication, "Specification for Structural Joints Using ASTM A325 or A490 Bolts," for ASTM A325, ASTM F1852, or ASTM A490 bolts, in accordance with the guidance in the GALL Report (Commitment No. 35).

Summary. Based on its audit, and review of the applicant's responses to RAIs B2.1.32-1, B2.1-27-1, and B2.1-27-2 of the applicant's ASME Section XI, Subsection IWE Program, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.S1, "ASME Section XI, Subsection IWE." The staff also reviewed the exceptions associated with the "scope of program," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria" program elements, and their justifications, and finds that the AMP, with the exceptions, is adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.27 summarizes operating experience related to the ASME Section XI, Subsection IWE Program. The applicant stated that no significant degradation or corrosion of the components of the containment liner has been identified. In 2000, areas of minor surface corrosion were identified on the Unit 2 liner near the interface of the liner and the concrete basemat. The applicant stated that no pitting of the liner plate was noted and that the areas of corrosion have been repaired. The applicant also stated that the most recent examination results for the Unit 1 and 2 containment liners were found to be acceptable, and no indications were found that would result in loss of intended function.

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 evaluated and incorporated 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.

During the audit, the staff reviewed CR 00-6787, which identified minor corrosion around the containment moisture barrier. The applicant stated that the condition had been repaired and found acceptable; however, it was not clear to the staff that the appropriate followup inspections had been conducted per IWE-2420. It was also unclear to the staff if an analysis of the moisture barrier area had been conducted to demonstrate that the augmented inspections of IWE-1241 were not necessary. Therefore, by letter dated August 15, 2011, the staff issued RAI B2.1.27-2 requesting that the applicant state whether the moisture barrier is identified as an area requiring augmented examination per IWE-1241, and if it is not, to provide justification. The staff also asked the applicant to discuss any degradation that has been identified on the moisture barrier itself.

In its response dated October 10, 2011, the applicant stated that the area near the moisture barrier at the interface between the containment steel liner and the concrete is not identified as an area requiring augmented examination per IWE-1241. Previous inspections of accessible surfaces in this area have not identified any substantial corrosion and pitting. There has been no indication of significant absence of or repeated loss of protective coating. There are no areas exposed to standing water, repeated wetting and drying, persistent leakage, or those with geometries that permit water accumulation, condensation, or microbiological attack. The applicant further stated that there have been no aging effects identified on the actual moisture barrier. The most recent inspection of the containment steel liner and the moisture barrier were performed in 2008, and no relevant indications were found for these components.

The staff finds the applicant's response acceptable because plant-specific operating experience has shown that the area near the moisture barrier, at the interface between the containment steel liner and the concrete, is not exposed to standing water, repeated wetting and drying, persistent leakage, or is of a geometry that permits water accumulation, condensation, and microbiological attack. With no indication or significant absence of or repeated loss of protective coatings, the augmented examinations discussed in IWE-1241 are not required. The staff's concern described in RAI B2.1.27-2 is resolved.

Based on its audit and review of the application and review of the applicant's responses to RAI B2.1.27-2, the staff finds that the applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A1.27 provides the UFSAR supplement for the ASME Section XI, Subsection IWE Program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the applicant committed (Commitment No. 35) to enhance the ASME Section XI, Subsection IWE Program procedures to specify the preventive actions for storage, protection, and lubricants recommended in Section 2 of RCSC publication "Specification for Structural Joints Using ASTM A325 or A490 Bolts" for ASTM A325, ASTM F1852, or ASTM A490 bolts, prior to entering the period of extended operation. The staff finds that the information in the UFSAR supplement, including Commitment No. 35, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's ASME Section XI, Subsection IWE Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions, and their justifications, and determines that the AMP, with the exceptions, is adequate to manage the applicable aging effects. 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).

3.0.3.2.23 ASME Section XI, Subsection IWL

Summary of Technical Information in the Application. LRA Section B2.1.28 describes the existing ASME Section XI, Subsection IWL Program as consistent, with an enhancement, with GALL Report AMP XI.S2, "ASME Section XI, Subsection IWL." The LRA states that the IWL containment inservice inspections will be performed in accordance with the 2004 edition of ASME Code Section XI, Subsection IWL (no addenda) supplemented with the applicable requirements of 10 CFR 50.55a(b)(2). The LRA states that the AMP addresses the aging effects of cracking due to expansion and loss of bond, loss of material, increase in porosity, and increase in permeability of the concrete containment and post-tensioning systems exposed to atmosphere and weather, plant indoor air, and buried environment. The LRA also states that the program manages these aging effects through periodic general visual examinations of the concrete containment structure and post-tensioning system. The applicant further stated that the Containment Inservice Inspection Program will be updated during each successive 120-month inspection interval to comply with the requirements of the latest edition and addenda of the ASME Code specified 12 months before the start of the inspection interval to conform with the 10 CFR50.55a(g)(4)(ii).

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.S2, "ASME Section XI, Subsection IWL."

For the "parameters monitored" and "acceptance criteria" program elements, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

The "parameters monitored" program element in GALL Report AMP XI.S2 recommends that concrete surfaces be examined for conditions indicative of degradation, as defined in

ACI 349.3R, “Evaluation of Existing Nuclear Safety-Related Concrete Structures.” However, during its audit, the staff noted grease stains on the Unit 2 containment wall and accumulated grease on the tendon gallery floor and ceiling around the grease cans during scheduled audit walkdowns. By letter dated August 15, 2011, the staff issued RAI B2.1.28-1 requesting that the applicant provide information for the following identified issues: (a) long-term effect of grease leakage on the strength and durability of concrete, (b) effects of loss of corrosion protection of the prestressing tendons and anchorage components due to leakage of grease from grease cans and tendon sheathing, and (c) long-term effects on concrete-rebar bonding.

In its response to RAI B2.1.28-1 dated October 11, 2011, the applicant stated that:
(a) Oak Ridge National Laboratory report ORNL/CP-102334, “An Investigation of Tendon Corrosion-Inhibitor Leakage into Concrete,” July 1999, concludes there is no evidence of harmful interactions between concrete and the corrosion inhibiting grease used as tendon sheathing filler in commercial nuclear power plants; (b) the quantity of grease leakage that has been identified is minor and has not inhibited the tendons from remaining adequately coated with the corrosion inhibitor, and plant-specific operating experience has not identified any unacceptable corrosion of the tendons; and (c) there has been no plant-specific or industry operating experience that would indicate that leakage of corrosion-inhibitor grease could contribute to a reduction of bond strength after the bond has properly formed. Furthermore, bonding between the conventional reinforcing steel and the concrete begins during the early stages of hydration and is essentially completed before the grease is installed later in the construction process.

The staff finds the applicant’s responses acceptable because: (a) ORNL/CP-102334 and NUREG/CR-6598 (ORLN/TM-13554) “An Investigation of Tendon Sheathing Filler Migration into Concrete,” March 1998, conclude that the containment structural capacities were not adversely affected due to tendon sheathing filler leakage into the containment concrete, (b) plant-specific operating experience has not identified any unacceptable corrosion of tendons, and minor leakage has not inhibited the tendons from remaining adequately coated with the corrosion inhibitor, and (c) there has not been any plant-specific and industry operating experience that indicate a loss of bond between concrete and reinforcing bar due to the leakage of tendon sheathing filler material. The staff also noted that bond between the concrete and rebar is not only due to the adhesion; friction due to roughness of the reinforcing-bar as well as mechanical bearing due to ribs on the reinforcing-bar surface also contribute to the bond. Therefore, the staff’s concern described in RAI B2.1.28-1 is resolved.

The “acceptance criteria” program element in GALL Report AMP XI.S1 recommends performing quantitative acceptance criteria based on the requirements of ACI 349.3R. However, during the audit, the staff noted that the plant-specific procedure that was used in 2010 for concrete containment inspections does not reference ACI 349.3R. As a result, it was not clear to the staff if the quantitative acceptance criteria of ACI 349.3R has been established for the containment exterior concrete surface examination of Units 1 and 2. By letter dated August 15, 2011, the staff issued RAI B2.1.28-3 requesting that the applicant: (a) explain if a quantitative acceptance criteria for the containment exterior concrete surface examination has been used and (b) if a quantitative acceptance criteria will be added to the AMP as an enhancement, provide plans and schedule to conduct base line inspections in accordance with the quantitative acceptance criteria prior to the period of extended operations.

In its response to RAI B2.1.28-3 dated October 10, 2011, the applicant stated that: (a) as documented in LRA Appendix B2.1.28, acceptance criteria, when degradation exceeding the acceptance criteria is found, then corrective actions and expansion of inspection scope are in accordance with ASME Code Section XI, Subsection IWL, ACI 201.1, and ACI 349.3R; (b) IWL-2510 specifies that concrete surface areas shall be visually examined for evidence of conditions indicative of damage or degradation, such as described in ACI 201.1 and ACI 349.3R; and (c) ACI 349.3R acceptance criteria have been used in the past inspections, as described in the LRA Bases Document for AMP XI.S2, "ASME Section XI, Subsection IWL Program." The applicant concluded that a new baseline inspection is not required. The applicant also stated that the most recent inspections of the exterior concrete surfaces on the containment buildings did not find any concrete crack indications wider than 0.010 inch, whereas ACI 349.3R states that passive cracks less than 0.015-inch wide are acceptable without further evaluation.

The staff finds the applicant's response acceptable because: (a) the applicant stated that the containment exterior concrete surface examination was performed in accordance with the plant specifications of ASME Code Section XI, Subsection IWL code and applicable ACI standards including ACI 201.1 and ACI 349.3R, and (b) identified cracks during the most recent inspections of the exterior concrete surfaces on the containment buildings were less than the first-tier criterion of maximum passive crack width of 0.015 inch of ACI 349.3R; thus, they meet the "acceptance criteria" program element of GALL Report XI.S2. The staff's concern described in RAI B2.1.28-3 is resolved.

The staff also reviewed the portions of the "scope of program," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," "corrective action," "confirmation process," and "administrative controls" program elements associated with an enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this enhancement follows.

<u>*Enhancement*</u>. LRA Section B2.1.28 states an enhancement to the "scope of program," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," "corrective actions," "confirmation process," and "administrative controls" program elements. In this enhancement, the applicant stated that procedures will be enhanced to incorporate the 2004 edition of ASME Code Section XI, Subsection IWL (with no addenda). The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S2 and finds it acceptable because, when it is implemented, it will incorporate the 2004 edition of the ASME Code, as approved in 10 CFR 50.55a and recommended in the GALL Report.

<u>*Summary*</u>. Based on its audit and review of the applicant's ASME Section XI, Subsection IWL Program, and review of the applicant's responses to RAI B2.1.28-1 and RAI B2.1.28-3, the staff finds that elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.S2. In addition, the staff reviewed the enhancement associated with the "scope of program," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," "corrective actions," "confirmation process," and "administrative controls" program elements and finds that, when implemented, it will make the AMP adequate to manage the applicable aging effects.

<u>Operating Experience</u>. LRA Section B2.1.28 summarizes operating experience related to the ASME Section XI, Subsection IWL Program. The staff reviewed operating experience information, in the application and during the audit, to determine whether the applicant reviewed the applicable aging effects, and industry and site-specific operating experience. 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 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" program element in GALL Report AMP XI.S2 recommends that the applicant's AMP for concrete containments consider the degradation concerns described in the NRC's generic communications, including NRC IN 99-10, "Degradation of Pre-stressing Tendon Systems in Pre-stressed Concrete Containments." Based on information provided in the LRA, review of the applicable calculations during the audit, and interviews with the applicant, it was not clear to the staff whether the effect of high temperature on the tendon prestressing forces, as described in IN 99-10, had been considered by the applicant as part of its AMP. By letter dated August 15, 2011, the staff issued RAI B2.1.28-2 requesting that the applicant explain how the effects of high temperature on the pre-stressing forces in tendons has been considered so that the containment's intended functions are maintained consistent with the CLB throughout the licensing period.

In its response dated October 11, 2011, the applicant stated that the actual lift-off tests through the first 20 years of plant life have been at least 95 percent of predicted, except for two that were 94 percent of predicted, and that most of the lifetime losses would have occurred during the first 20 years and would have been seen in surveillances conducted during the first 20 years of plant life. On the logarithmic scale, these exceptions during the period of 40 to 60 years of the plant life are very small compared to the losses during the first 20 years. The surveillance data through the first 20 years closely matches predicted losses. This confirms the accuracy of the method used to predict losses. The applicant further stated that IN 99-10 includes the observation that the steel relaxation in containment tendons at some plants has been more rapid than predicted. This was attributed to elevated temperatures; therefore, actual lifetime (40 years) relaxation losses may be in the range of 15.5 to 20 percent at approximately 32 °C (90 °F). The applicant used tests at approximately 20 °C (68 °F) to validate the conservatism of the predicted losses. The applicant predicted relaxation loss over 40 years for the typical tendon as 10 percent of installed tendon stress. The applicant stated that, when compared to the 20 percent loss suggested by IN 99-10, this would imply an additional 10 percent loss is possible. Finally, the applicant stated that if this discrepancy existed, it would have been observed during the surveillance.

The staff noted that most of the lifetime tendon losses typically occur during the first 20 years and would have been seen in surveillances conducted during the first 20 years of plant life. The staff also recognizes that lifetime tendon losses are not short-lived phenomena; however, the loss in prestress should continue at a diminishing rate until the end of the period of extended operation. The staff finds the applicant's response to RAI B2.128-2 acceptable because the applicant conducts periodic tendon surveillances, and any discrepancy in total tendon relaxation loss (including loss due to temperature) would be observed during these surveillances. In addition, the surveillance data through the first 20 years closely matches predicted tendon losses. Furthermore, the applicant has a TLAA, "Concrete Containment Tendon Prestress Analysis," that compares the original design predictions and the regression analyses of the tendon surveillance data to predict the future performance of the post-tensioning system to ensure that tendons continue to maintain adequate prestress during the period of extended operation. Therefore, the staff determined that the intended functions of the containment structures will be maintained consistent with the CLB throughout the operating licensing period. The staff's concern described in RAI B2.1.28-2 is resolved.

Based on its audit and review of the application and the review of the applicant's response to RAI B2.1.28-2, the staff finds that the applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A1.28 provides the UFSAR supplement for the ASME Section XI, Subsection IWL Program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1.

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 ASME Section XI, Subsection IWL Program, the staff determines that the 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. 22 prior to the period of extended operation—will make the AMP adequate to manage the applicable aging effects. In a letter dated June 2, 2014, the applicant informed the NRC that all actions associated with Commitment No. 22 have been completed. 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 operations, as required by 10 CFR 54.21(a)(3). The staff reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.24 ASME Section XI, Subsection IWF

Summary of Technical Information in the Application. LRA Section B2.1.29 describes the existing ASME Section XI, Subsection IWF Program as consistent, with an enhancement, with GALL Report AMP XI.S3, "ASME Section XI, Subsection IWF." The LRA states that the AMP manages aging of supports for ASME Code Class 1, 2, and 3 piping and components for loss of material, cracking, and loss of mechanical function. The LRA states that visual inspections of Class 1, 2, and 3 piping and component supports will be performed in accordance with the ASME Code Section XI, 2004 edition with no addenda. The LRA also states that the ISI Program is updated during each successive 120-month inspection interval to comply with the requirements of the latest edition of the ASME Code, specified 12 months before the start of the inspection interval, in accordance with 10 CFR 50.55a.

The LRA states that selection of components for examination, acceptance standards, and scope of inspection for supports complies with the requirements of ASME Code Section XI, Subsection IWF. The LRA also states that the program meets the ASME Code for reexamination of component supports and extends the examination to include additional components when such actions are required by the code. The instructions and acceptance criteria for the visual examinations are included in plant procedures.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.S3.

For the “preventive actions” and “monitoring and trending” program elements, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

The “preventive actions” program element in GALL Report AMP XI.S3 recommends that for structural bolting consisting of ASTM A325, ASTM F1852, or ASTM A490 bolts, the preventive actions for storage, lubricants, and SCC potential—discussed in Section 2 of RCSC publication “Specification for Structural Joints Using ASTM A325 or A490 Bolts”—need to be used. During its audit, the staff confirmed that appropriate visual inspections are conducted on structural bolts; however, it found that the applicant’s ASME Section XI, Subsection IWF Program did not address the preventive actions discussed in Section 2 of RCSC “Specification for Structural Joints Using ASTM A325 or A490 Bolts” for ASTM A325, ASTM F1852, and ASTM A490 bolts. By letter dated August 15, 2011, the staff issued RAI B2.1.32-1 requesting that the applicant explain how, for ASTM A325, ASTM F1852, or ASTM A490 bolts, the actions discussed in Section 2 of “Specification for Structural Joints Using ASTM A325 or A490 Bolts” are addressed or why they are unnecessary.

In its response dated October 10, 2011, the applicant stated that plant procedures will be enhanced to include the preventive actions recommended in Section 2 of RCSC “Specification for Structural Joints Using ASTM A325 or A490 Bolts” for ASTM A325, ASTM F1852, or ASTM A490 bolts. The applicant stated that the LRA Section B2.1.29, the other Appendix B sections that apply to high-strength structural bolting (Sections B2.1.27, B2.1.32, and B2.1.33), and the applicable LRA basis documents will be revised to include an enhancement to specify the preventive actions for storage, protection, and lubricants recommended in Section 2 of RCSC “Specification for Structural Joints Using ASTM A324 or A490 Bolts.” The applicant also revised its commitments in LRA Table A4-1 (Commitment Nos. 23, 25, and 26) to include these preventive actions.

The staff finds the applicant’s response acceptable because the applicant will follow the preventive actions discussed in RCSC “Specification for Structural Joints Using ASTM A325 or A490 Bolts,” which is the guidance recommended in the GALL Report for use on ASTM A325, ASTM F1852, and ASTM A490 bolts. The staff’s concern in RAI B2.1.32-1 is resolved.

During its review of the “detection of aging effects” program element in the applicant’s Bolting Integrity Program, the staff identified that although GALL Report AMP XI.M18 recommends volumetric examination of high-strength structural bolting (actual measured yield strength greater than or equal to 150 ksi) in sizes greater than 1-inch nominal diameter, the applicant’s program included only visual examination. The staff issued RAIs B2.1.7-2 and B2.1.7-3 regarding this issue; the staff’s review and discussion is located in SER Section 3.0.3.2.5. As a result of the staff’s concerns, the applicant revised its ASME Section XI, Subsection IWF and Structures Monitoring programs to include volumetric examinations performed in accordance with ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, of a representative sample of high-strength bolts. The revised LRA Section B2.1.29 states that the representative sample size is 20 percent with a maximum of 25 per unit of high-strength bolts greater than 1-inch nominal diameter with actual yield strength greater than or equal to 150 ksi. The revised LRA also states that the bolts will be selected from areas most susceptible to SCC. Further, in a teleconference held January 18, 2012, the applicant stated that the frequency of volumetric inspections will be consistent with the frequency of the visual inspections performed by ASME Code IWF.

The staff finds this revision to the IWF Program acceptable because high-strength structural bolts will be volumetrically examined for SCC in accordance with ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, as recommended in the GALL Report, and the representative sample of bolts selected for volumetric testing will be based on bolts in the most susceptible areas.

The “monitoring and trending” program element in GALL Report AMP XI.S3 recommends that examinations of component supports that reveal indications that exceed the acceptance standards and require corrective measures be extended to include additional examinations in accordance with ASME Code Section XI, Subsection IWF-2430. During its onsite audit, the staff noted instances in which component supports that are part of the IWF Inspection Program sample have been inspected and showed signs of aging-related degradation significant enough to be entered into the applicant’s CAP but still not meeting the acceptance criteria threshold of “unacceptable for continued service,” as defined in ASME Code IWF-3400. In these cases, no additional inspections were performed and the scope of examination was not increased, since the ASME Code requires such only after the component support has exceeded the acceptance criteria. The IWF AMP is used to detect and monitor aging-related degradation of the same sample of components every 10-year interval to manage aging of the entire population of components with the same material and environment. When a component support that is part of the IWF inspection sample is re-worked to an “as-new” condition, it is no longer representative of the aging of the other supports in the population. Therefore, by letter dated August 15, 2011, the staff issued RAI B2.1.29-1 requesting that the applicant describe how repairing a component support outside of the ASME Code ISI Program criteria, resulting in an “as-new” ISI Program sample component, without an expansion of ISI Program sample population size, will be effective in managing similar and adjacent components that are not included in the ISI Program sample population.

In its response dated October 10, 2011, the applicant stated that it will modify its AMP procedure to incorporate the following guidance: When component support conditions are found to include minor aging-related degradation that does not meet the threshold of “unacceptable for continued service,” as defined in IWF-3400, an evaluation will be performed in accordance with the CAP. If this evaluation determines that the component, without repair, will continue to perform its intended function until the next scheduled inspection, the component support will not be repaired but will be monitored for increased degradation. The applicant also stated that the evaluation will also consider which inspections or repairs may be required for similar or adjacent components not included in the ISI Program sample population and assure that additional inspections are performed during the next scheduled inspection. The applicant finally stated that, as an alternative, it may choose to repair the degraded component and replace it in subsequent inspections by a randomly selected component that is more representative of the general population.

The staff finds the applicant’s response acceptable because the planned modifications to its ISI-IWF inspection procedures will ensure that aging-related degradation of the component, material, and environment total population will be identified and managed through the period of extended operation. The staff’s concern described in RAI B2.1.29-1 is resolved.

The staff also reviewed the portions of the “scope of program,” “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” “acceptance criteria,” and “corrective action” program elements associated with the enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff’s evaluation of this enhancement follows.

Enhancement. LRA Section B2.1.29 states an enhancement to the “scope of program,” “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” “acceptance criteria,” and “corrective actions” program elements. In this enhancement, the applicant stated that procedures will be enhanced to incorporate the 2004 edition of ASME Code Section XI, Subsection IWF (with no addenda). The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S3 and finds it acceptable because, when it is implemented, it will incorporate the 2004 edition of the ASME Code as approved in 10 CFR 50.55a and recommended in the GALL Report.

Summary. Based on its audit and review of the applicant’s ASME Section XI, Subsection IWF Program and the applicant’s response to RAI B2.1.29-1, the staff finds that program elements one through six, for which the applicant claimed consistency with the GALL Report, are consistent with the corresponding program elements of GALL Report AMP XI.S3. In addition, the staff reviewed the enhancement associated with the “scope of program,” “parameters monitored or inspected,” “detection of aging effects,” “monitoring and trending,” “acceptance criteria,” and “corrective actions” program elements and finds that, when implemented, it will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.29 summarizes operating experience related to the ASME Section XI, Subsection IWF Program. The LRA states that during the 2RE13 outage ISI-IWF inspections, two ASME Code Class 1 support spring cans were found with out-of-tolerance load readings and one with an out-of-plate reading. The LRA also states that there was one ASME Code Class 3 support found with corroded bolts. The applicant’s review of 10 years of plant-specific operating experience did not identify any program adequacy or implementation issues, and industry operating experience was evaluated for relevancy to the applicant’s program. During its audit, the staff reviewed the condition reports for the referenced operating experience and confirmed that the conditions were appropriately entered into the applicant’s CAP and addressed or dispositioned per the ASME Code.

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 evaluated and incorporated 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 applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A1.29 provides the UFSAR supplement for the ASME Section XI, Subsection IWF Program.

The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1.

The staff also noted that the applicant committed (Commitment No. 23) to enhance the existing ASME Section XI, Subsection IWF Program to incorporate the 2004 edition of ASME Code Section XI, Subsection IWF (with no addenda).

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's ASME Section XI, Subsection IWF Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that its implementation—through Commitment No. 23 prior to the period of extended operation—will make the AMP adequate to manage the applicable aging effects. 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).

3.0.3.2.25 10 CFR Part 50, Appendix J

Summary of Technical Information in the Application. LRA Section B2.1.30 describes the existing 10 CFR Part 50, Appendix J, Program as consistent, with exceptions and an enhancement, with GALL Report AMP XI.S4, "10 CFR Part 50, Appendix J." The LRA states that the 10 CFR Part 50, Appendix J, Program manages cracking, loss of material, and leakage to assure that loss of leak tightness and loss of sealing are within specified limits. The LRA also states that the program's focus is to provide measures to detect and identify degradation of the containment pressure boundary and its components, including seals and gaskets in support of the applicant's ASME Section XI, Subsection IWE Program, prior to loss of their intended functions, not (focused on) prevention of aging. The applicant stated that the program is in compliance with 10 CFR Part 50, Appendix J, and uses the performance-based approach (Option B) for the containment leak-rate testing frequency. Leak rate tests are performed in accordance with RG 1.163, "Performance-Based Containment Leak-Test Program," NEI 94-01, "Industry Guidance for Implementing Performance-Based Options of 10 CFR Part 50, Appendix J," and American National Standards Institute (ANSI)/American Nuclear Society (ANS) 56.8, "Containment System Leakage Testing Requirements." These standards provide assurance of acceptable leakage rates through the primary containment and systems and components penetrating the primary containment. The allowable leakage rate limits are specified in the TS. The applicant also stated that through periodic monitoring and testing of primary containment penetrations and isolation valves for leakage rates, proper maintenance and repairs are made to prevent loss of associated SC function(s).

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.

The staff also reviewed portions of the "corrective actions" program element to determine whether the program will be adequate to manage the aging effects for which it is credited for the period of extended operation. The staff's evaluation of this enhancement follows.

Enhancement. LRA Section B2.1.30 describes an enhancement to the "corrective actions" program element. In this enhancement, the applicant stated that its procedure will be enhanced to specify a surveillance frequency of 10 years following a successful Type A test. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S4 that states corrective actions are taken in accordance with 10 CFR Part 50, Appendix J, and NEI 94-01, with a particular focus on unacceptable leakage rates. The staff discussed with the applicant that, in accordance with the GALL Report, the enhancement should have been under the "monitoring and trending" program element, which deals with the frequency of testing over the licensing period. The staff, however, noted this enhancement as presented in the LRA, met the provision of aging management of the GALL Report AMP XI.S4. The staff, therefore, finds the enhancement acceptable because, when it is implemented, it will satisfy the criteria set by 10 CFR Part 50, Appendix J, and NEI 94-01 for Option B Type A tests.

Summary. Based on the audit, the staff finds that element one through six of the applicant's 10 CFR Part 50, Appendix J, Program are consistent with the corresponding program elements of GALL Report AMP XI.S4 and, therefore, are acceptable.

Operating Experience. LRA Section B2.1.30 summarizes operating experience related to the 10 CFR Part 50, Appendix J, Program. The applicant's latest Type A tests at pressure—and with a maximum allowable leakage rate of 0.3 percent—of the containment air volume for Unit 1, performed in late 2009, and for Unit 2, performed in mid-2007, resulted in as-found leakage rates of 0.1180 and 0.1423 percent containment air volume by weight per day, respectively. The allowable leakage rate for Types B and C tests is 455,050 standard cubic centimeters per minute (sccm). In addition, the applicant an administrative maintenance leakage rate of 200,000 sccm. The applicant tabulated the Unit 1 and Unit 2 Type B and C test results in the LRA for the maximum path and minimum path conditions of as-found and as-left conditions. The applicant stated that Type A leakage rates are less than half the maximum allowable leakage rate at test pressure, and Type B and C leakage rates are less than one fourth of maximum allowable and less than half of the administrative limit. The applicant also stated that the results of the containment leakage rate tests were well below the allowable rates for all tests.

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 evaluated and incorporated 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 RAIs, as discussed below. Specifically, during the audit, the staff found an exemption and relief related to the applicant's 10 CFR Part 50, Appendix J, Program.

The staff noted the exemption is related to components that the applicant identified as LSS and NRS containment isolation valves and related components, which in accordance with 10 CFR Part 50, Appendix J, Option B, are subject to Type C tests. The applicant requested and was granted an exemption for certain components from the 10 CFR Part 50, Appendix J, Option B for Type B and C Tests, for the life of each unit. The scope of the exemption includes containment isolation valves categorized as LSS or NRS. The staff determined that this exemption is for the life of the units; however, the exempted components could still be subject to failures. A search through the operating experience database indicated that containment isolation valves could be damaged by operating conditions. NRC issued IN 2006-15, “Vibration-Induced Degradation and Failure of Safety-Related Valves,” to inform applicants of possible vibration-induced degradations and failures of containment isolation valves. The staff noted that UFSAR Section 13.7, “Risk Informed Special Treatment Requirements,” states the LSS and NRS components, though exempted from the scope of the NRC regulations, are still subject to normal industrial and commercial practices. As described in the applicant’s letter to the NRC, dated August 31, 2000 (ADAMS Accession No. ML37490010), the alternate reliability strategy for their special treatment is to monitor and restore the affected functions either through corrective actions or a periodic feedback process. It was not clear to the staff, however, what actions the applicant has taken in regard to management of aging effects to which they may be subjected.

By letter dated August 15, 2011, the staff issued RAI B2.1.30-1 requesting that the applicant do the following:

(a) identify whether the containment boundary pressure-retaining components exempted from Type B and C testing have been included in the scope of license renewal

(b) describe if any modifications or corrective actions on the LSS/NRS valves/penetrations, including those in response to IN 2006-15, that have taken place and impacted these components to the extent they are now subject to 10 CFR Part 50, Appendix J, testing

(c) discuss whether the specific controls set to ensure the functionality of the valves and integrity of penetrations during CLB would also be applicable and adequate to manage such aging effects as cracking, loss of material, loss of leak tightness and sealing, during the period of extended operation

(d) indicate any other components that have been exempted under 10 CFR 50.12(a)(2)(vi), but subject to 10 CFR 54.4 and how did the applicant disposition these within the LRA

In its response to RAI B2.1.30-1 dated October 10, 2011, the applicant stated, for Part (a), that the isolation valves and penetrations that are elements of the containment boundary pressure-retaining components are within the scope of license renewal, and those exempted from Type B and C testing are still subject to Type A testing and visual examination, if required under the 10 CFR Part 50, Appendix J, Program. For Part (b), the applicant stated that there were no modifications to the plant’s LSS or NRS containment pressure boundary pressure-retaining components, including those in response to IN 2006-15. The applicant also stated that no SCs are exempt from the scope of license renewal based on risk significance and that the aging effects of any LSS or NRS SCs having an intended function will be managed for aging effects for the period of extended operation. The applicant described the management of aging LSS and NRS SCs in procedure OPSP1 1-ZA-0005, “Local Leakage Rate Test Calculations, Guidelines, and Program.” The applicant also stated that UFSAR Chapter 13.7, “Risk informed Special Treatment Requirements,” provides details of the process. Parts (a) and (b) of the applicant’s responses were repeated in Parts (c) and (d)—that the functionality of the LSS and NRS valves and integrity of penetrations are ensured by managing the aging of those components with the appropriate AMP, and no SSCs are exempt from the scope of license renewal based on risk significance. Those credited with performing an intended function will be managed for aging throughout the period of extended operation as discussed under Part (b).

The staff reviewed the applicant's response to Part (a) and confirmed that exempted LSS and NRS containment boundary pressure-retaining components have been scoped and screened based on 10 CFR 54.4 and 10 CFR 54.21(a)(1) because LRA Sections 3.1 through 3.6 contain relevant AMRs for families of SCs within the population of SSCs regardless of the components' special treatment classification. The staff also reviewed the exempted LSS and NRS containment boundary pressure-retaining components as part of its "Scoping and Screening Program Review," in Section 2.1.3.2 and, therefore, after evaluating the applicant's response to RAI 2.1-4 (i.e., no LSS or NRS SSCs were excluded from the population categories of 10 CFR 54.4), the staff found that the LSS and NRS components were appropriately scoped into the license renewal program. The staff noted that, in accordance with GALL Report AMP XI.S4, the applicant performs the integrated leak rate test (ILRT) to assure the overall leak tightness of the containment. For Parts (b), (c), and (d), the staff reviewed the UFSAR and confirmed that there were no entries related to IN 2006-15 and no changes to the original exemptions regarding Type B or C testing of LSS and NRS containment boundary pressure-retaining components. The staff also noted that UFSAR Section 13.7 describes the applicant's feedback and corrective action processes to ensure that equipment performance changes, application of special treatments, and other corrective actions are re-evaluated for determining the current risk significance of components—including those designated as LSS or NRS. Furthermore, the applicant performs a comprehensive review of appropriate databases, such as that of the Maintenance Rule Program and the Operating Experience Review, at least once every other refueling outage and takes corrective actions. The applicant stated that this maintenance process establishes the scope, frequency, and detailed activities necessary to determine functionality of the LSS and NRS SCs, including post-maintenance testing to provide assurance that the exempted LSS and NRS SCs are functional.

The staff also noted that, although UFSAR Section 13.7 provides measures so that the exempted LSS and NRS components maintain their functionality, it lacks the specifics of managing aging effects for these components. The staff was concerned as to how aging effects would be managed for these exempted components and which AMPs would be used. In two teleconferences held on April 9, 2012, and April 16, 2012, the staff discussed these concerns with the applicant. The applicant agreed to provide additional information that would consolidate its AMPs for the exempted components, in particular, that the components are within the scope of license renewal and that the applicant will manage the effects of aging by means of appropriate AMPs (e.g., Water Chemistry, One-Time Inspection, and Lubricating Oil Analysis). The applicant also agreed that the valves would be part of the pool of eligible components for sampling under those programs for the applicable material and environment combinations, and the valves' entries in the LRA AMR tables will be revised, as necessary, to reflect this approach. The staff and the applicant agreed that this information would be provided as a supplement to the applicant's response to RAI B2.1.30-1.

By letter dated April 26, 2012, the applicant provided its supplemental response to RAI B2.1.30-1, indicating that the containment isolation valves exempted from 10 CFR Part 50, Appendix J, testing, and their penetrations (denoted by M-xx in the list below) are managed for aging effects in accordance with the following:

- Carbon steel valves and associated penetrations will be managed as follows:
  - M-23 through M-28, M-34, M36, and M-38 through M-40, internally exposed to CCCW environment, will be managed with the Closed-Cycle Cooling Water Program. External surfaces exposed to plant indoor air will be managed with the External Surfaces Monitoring Program.
  - M-75, internally exposed to lubricating oil environment, will be managed with the Lubricating Oil Analysis and the One-Time Inspection programs. External surfaces exposed to plant indoor air will be managed with the External Surfaces Monitoring Program.
  - M-68A, M-57, and M-58, which are internally and externally exposed to plant indoor air environment, will be managed with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and the External Surfaces Monitoring programs.
- Stainless steel valves and associated penetrations will be managed as follows:
  - M-12, M-16, M-45, M-61, and M-79, internally exposed to demineralized water, will be managed with the Water Chemistry and the One-Time Inspection programs. For external surfaces exposed to plant indoor air external environment, the applicant did not propose any programs.
  - M-30, M-68C, M-80A, M-80D, M-80E, M-80F, M-82A, M-82D, M-82E, and M-88, internally exposed to plant indoor air environment, will be managed with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. For external surfaces exposed to plant indoor air external environment, the applicant did not propose any programs.
  - M-09, M-13, M-17, M-29, M-45, M-68E, M-85A, M-85B, M-85E, and M-86, internally exposed to treated borated water environment, will be managed with the Water Chemistry and the One-Time Inspection programs. For external surfaces exposed to plant indoor air external environment, the applicant did not propose any programs.
- Austenitic stainless steel valves and associated penetrations will be managed as follows:
  - M-82A exposed to plant indoor air environment is proposed to be managed with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. For plant indoor air external environment, the applicant did not propose any programs.
  - M-56 exposed to treated borated water environment is proposed to be managed with the Water Chemistry and the One-Time Inspection programs. For plant indoor air external environment, the applicant did not propose any programs.
- Valves exposed to an internal environment of nitrogen will be managed as follows:
  - These valves will be managed with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program.
  - The environment for these valves in LRA Tables 3.2.2-4 and 3.3.2-22 is revised from dry gas to plant indoor air to conservatively manage internal condensation since these valves are exempt from 10 CFR Part 50, Appendix J, Type B and C surveillance testing.

The staff's evaluations of the AMPs referred to above are located in this SER as follows:

- Closed-Cycle Cooling Water Program, SER Section 3.0.3.2.7
- External Surfaces Monitoring Program, SER Section 3.0.3.2.16
- Lubricating Oil Analysis Program, SER Section 3.0.3.2.19
- One-Time Inspection Program, SER Section 3.0.3.1.4
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, SER Section 3.0.3.2.18
- Water Chemistry Program, SER Section 3.0.3.2.1

The staff reviewed the applicant's supplemental response to RAI B2.1.30-1 for the LSS and NRS valves exempted from 10 CFR Part 50, Appendix J, Type B and C testing, dated April 26, 2012, and noted that the reported matrix of valves, penetrations, and applicable environments were in agreement with the exemption proposal, as stated in the letter to the NRC dated August 31, 2000. The staff also noted that additional proposed valves listed in the August 31, 2000, letter, although not included in the April 26, 2012, matrix of valves and penetrations, are still scoped and screened in the appropriate LRA tables. For example, valves associated with penetrations M-33, M-35, and M-37 are scoped and screened in Table 3.2.2-3, "Engineered Safety Features—Summary of Aging Management Evaluation—Residual Heat Removal System." A component can be excluded from 10 CFR Part 50, Appendix J, Type B or Type C testing, per ANSI/ANS-56.8-2002, under the following conditions:

- It does not constitute a potential primary containment atmospheric pathway during and following a design-basis accident.
- It has boundaries sealed with a qualified seal system.
- It includes test connections, vents, and drains between primary containment isolation barriers that are: (a) 1-inch nominal diameter or less in size; (b) administratively secured closed; and (c) a double barrier (e.g., two valves in series, one valve with a nipple and cap, one valve and a blind flange).

The staff's individual AMR item evaluations for the exempted components, yet still managed for aging within the scope of license renewal, are documented in the appropriate SER sections based on their listings in respective LRA Table 2 system sections and associated Table 1 references.

The staff determined that the applicant's plan—to manage the safety function of leak tightness and associated aging effects (e.g., cracking, loss of material, loss of sealing) of the exempted or excluded containment pressure boundary components through mechanical programs, consistent with the GALL Report—was acceptable because it will monitor age-related pressure boundary degradation such as cracking, loss of material, loss of sealing, and loss of leak tightness. The staff's concerns described in RAI B2.1.30-1 and its supplement are resolved.

During the audit, the staff also noted that the applicant requested and was granted a relief for Units 1 and 2 from the requirements of ASME Code Section XI, Article IWE-5000 to perform VT-2 visual examinations in connection with system pressure testing following repairs or modifications of pressure-retaining boundaries or replacement of Class MC and Class CC components. As an alternative to the VT-2 examination, the applicant proposed in the LRA to rely on Type B and Type C testing conducted pursuant to 10 CFR Part 50, Appendix J, to detect leakage from pressure-retaining components (the staff noted that the applicant currently performs its testing in this manner). In conjunction with the test, the applicant also proposed to perform a general visual examination of the accessible areas to further ensure the overall integrity of the repaired or replaced component(s). For deferred or unperformed tests, the applicant would perform a VT-1 or detailed visual examination test for repairs or replacements affecting the containment pressure boundary. The staff noted that the current license reliefs for STP, Units 1 and 2, are for the current licensing period. The staff noted, therefore, that the applicant did not clearly address how it would maintain an acceptable level of containment pressure boundary integrity during the period of extended operation. By letter dated August 15, 2011, the staff issued RAI B2.1.30-2, asking the applicant to identify a plan of action to satisfy ASME Code requirements, under Article IWE-5000 of Section XI, for VT-2 visual examinations in connection with the system pressure testing following repairs or modifications of pressure-retaining boundaries or replacement of Class MC and Class CC components.

In its response to RAI B2.1.30-2 dated October 10, 2011, the applicant stated that testing and visual examinations performed during the period of extended operation will be in accordance with the ASME Code edition applicable at that time, consistent with the provisions of 10 CFR 50.55a. The applicant also stated that any variances from these requirements will be submitted to the NRC for approval.

The staff finds the applicant’s response to RAI B2.1.30-2 acceptable because the applicant intends to use the *Code of Federal Regulations* regarding the requirements to perform visual examinations or other NRC-approved inspection procedures in connection with system pressure testing following repairs, modifications, or replacement of containment boundary pressure-retaining components.

Based on its audit and review of the LRA, and the applicant’s responses to RAI B2.1.30-1 and RAI B2.1.30-2, the staff finds that the applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

By letter dated June 28, 2016, the applicant revised LRA AMP B2.1.30, “10 CFR Part 50, Appendix J,” through its annual 2016 LRA update (see ADAMS Accession No. ML16190A135). Although the applicant previously claimed the LRA AMP B2.1.30 to be consistent with an enhancement, the revised AMP took an exception to RG 1.163, referenced in the GALL Report, Revision 1, as the implementing document to 10 CFR Part 50, Appendix J. The exception stated that the new implementing document for 10 CFR Part 50, Appendix J, is NEI 94-01, Revision 2-A, “Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J.” The applicant also revised the enhancement to the “corrective actions” program element. The revised “corrective actions” program element revised the program procedures for the performance-based surveillance frequency for Option B, following a successful completion of a Type A test, from 10 to 15 years (plus a grace period of up to 9 months with a basis provided), consistent with NEI 94-01, Revision 2-A. In addition, the applicant deleted from the LRA AMP B2.1.30 program description and UFSAR supplement compliance of the “10 CFR Part 50, Appendix J” program to the ANSI/ANS 56.8, “Containment System Leakage Testing Requirements.” The basis for the amended AMP is the NRC approval (ADAMS Accession No. ML16116A007) of a STP license amendment request (LAR) (ADAMS Accession Nos. ML15128A352 and ML15329A304) to adopt, subject to specific conditions, NEI 94-01, Revision 2-A, as the implementing document for Type A tests and extends the performance-based testing interval to 15 years on a routine basis following the one-time extension of 15 years approved in 2002 (ADAMS Accession No. ML022410163).

On August 11, 2016, the staff held a teleconference with the applicant (ADAMS Accession No. ML16236A304) and noted that the 2016 Annual Update did not identify the specific AMP XI.S4 program elements to which the revised LRA AMP B2.1.30 took exceptions. The applicant acknowledged this omission and agreed to provide a revised amended LRA AMP B2.1.30 identifying the program elements of GALL Report AMP XI.S4 to which the exception would apply.

By letter dated September 28, 2016 (ADAMS Accession No. ML16285A406), the applicant supplemented the amended LRA AMP B2.1.30 specifying that the exception taken to GALL Report AMP XI.S4 applies to “monitoring and trending” and “corrective actions” program elements. In this supplement, the applicant also provided an enhancement to the “monitoring and trending” program element of LRA AMP B2.1.30.

The staff considers the stated exceptions to “monitoring and trending” and “corrective actions” program elements as being portions of the GALL Report AMP XI.S4 that the applicant does not intend to implement. The SRP-LR, Revision 1 (and Revision 2), states that an applicant may take one or more exceptions to specific GALL Report AMP elements, and that any exception should be described and justified. Similarly, SRP-LR, Revision 1 (and Revision 2), considers enhancements to be revisions or additions to existing AMPs that the applicant commits to implement prior to the period of extended operation. 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.

The deletion of ANSI/ANS 56.8, “Containment System Leakage Testing Requirements,” from the AMP program description and UFSAR in the 2016 Annual Update is acceptable, because NEI 94-01, Revision 2-A, incorporates by reference ANSI/ANS 56.8. The staff reviewed the technical justifications for the exceptions and enhancements addressing portions of the “monitoring and trending” and “corrective actions” program elements, including associated operating experience from the NRC-approved LAR, to assess whether the amended LRA AMP B2.1.30 is adequate to manage the effects of aging for SSCs within the scope of the Containment Leak Rate program. The staff’s evaluation of these exceptions and enhancements follows.

Exceptions 1 and 2: LRA Section (AMP) B2.1.30, as amended by letter dated June 28, 2016, and supplemented by letter dated September 28, 2016, states the following exception to both the “monitoring and trending” and “corrective actions” program elements. In these identical exceptions, the applicant stated:

> The STP 10 CFR Part 50, Appendix J, program is revised to use the guidance provided in NEI 94-01 Revision 2-A. NUREG-1801 Rev 2 removed the revision number from NEI 94-01 which allows the use of the guidance provided in NEI 94-01, Revision 2-A. Additionally, STP Amendment Nos. 210 and 197 to the Unit 1 and 2 Facility Operating Licenses, respectively, revises Technical Specification Section 6.8.3.j to state this program shall be in accordance with the guidelines contained in NEI topical report NEI 94-01 Revision 2-A, dated October 2008.

The staff reviewed Exceptions 1 and 2 to “monitoring and trending” and “corrective actions” program elements and finds them acceptable because when applied they would continue to adequately manage aging effects by aligning the LRA AMPB2.1.30 with GALL Report (Revision 2) and NRC-approved Section 6.8.3.j, “Containment Leakage Rate Testing Program,” of the Technical Specifications which states: “A program shall be established to implement leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in NEI topical report NEI 94-01 Revision 2-A, dated October 2008.”

Enhancement 1 (as Revised). LRA AMP B2.1.30, as amended by letter dated June 28, 2016, and supplemented by letter dated September 28, 2016, revised the original enhancement to the “corrective actions” program element (see above). In the revised enhancement, the applicant commits to change the testing interval in the program procedures after the successful completion of a Type A test, from 10 to 15 years. The staff reviewed this revised enhancement against the corresponding program element in GALL Report, Revision 1, AMP XI.S4, which states that corrective actions are taken in accordance with 10 CFR Part 50, Appendix J and NEI 94-01. The staff finds the enhancement acceptable because when implemented the revised surveillance frequency does not reduce the scope of the “corrective actions” program element LRA AMP B2.1.30, as amended. Further, the revised input to the “corrective actions” program element is in accordance with NEI 94-01, Revision 2-A, incorporated in GALL Report (Revision 2), and as approved by NRC in the SE of the STP LAR, which affirms that STP Units 1 and 2 have in place a CAP to address poor performing Type C components that contribute to the performance leakage rate criterion as defined in NEI 94-01, Revision 2-A.

Enhancement 2. LRA Section B2.1.30, as supplemented by letter dated September 28, 2016, includes an enhancement to the “monitoring and trending” program element. In this enhancement, the applicant commits to revise the program procedures to specify a Type A test interval of 15 years following a successful Type A test. The staff reviewed this revised enhancement against the corresponding program element in GALL Report AMP XI.S4 that states the entire pressure boundary is monitored over time and that additional details for implementing Option B are provided in RG 1.163 and NEI 94-01, Rev. 0. The staff finds the enhancement acceptable because when implemented the revised surveillance frequency does not reduce the scope of the “monitoring and trending,” program element of the revised amended LRA AMP B2.1.30. Further, the revised input to the “monitoring and trending” program element is in accordance with NEI 94-01, Revision 2-A, as approved by NRC in the SE of the STP LAR (ADAMS Accession No. ML16116A007), which indicates examination schedules for monitoring for the purpose of trending STP Unit 1 and Unit 2 IWL concrete, tendon prestress, and IWE containment metal liners.

Based on the above review of the exceptions and enhancements associated with the “monitoring and trending” and “corrective actions” program elements and their justifications, the staff finds that the LRA AMP B2.1.30, with exceptions and enhancements, is consistent with GALL Report AMP XI.S4, and adequate to manage the applicable aging effects.

UFSAR Supplement. LRA Section A1.30, as amended by LRA update dated June 28, 2016, provides the UFSAR supplement for the 10 CFR Part 50, Appendix J, Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program, as described in SRP-LR Table 3.0-1.

The staff also notes that the applicant committed (Commitment No. 24, as amended by LRA update dated June 28, 2016) to enhance the 10 CFR Part 50, Appendix J, Program procedures no later than 6 months prior to the period of extended operation, to specify a surveillance frequency of 15 years following a successful ILRT. The updated commitment would revise program procedures that were in effect following a one-time extension approved in 2002 in the testing interval of Type A test (ILRT) from 10 years, consistent with the guidance in RG 1.163, to 15 years, consistent with the guidance of NEI 94-01, Revision 2-A..

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's 10 CFR Part 50, Appendix J, Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and determines that the AMP, with exceptions, is adequate to manage the applicable aging effects. Also, the staff reviewed the enhancement and confirmed that their implementation through Commitment No. 24 (as amended by LRA update dated June 28, 2016) prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d)..

3.0.3.2.26 Structures Monitoring Program

Summary of Technical Information in the Application. LRA Section B2.1.32 describes the existing Structures Monitoring Program as consistent, with enhancements, with GALL Report AMP XI.S6, "Structures Monitoring Program." The LRA states that the AMP monitors the condition of structures and structural supports that are within the scope of license renewal to manage for concrete cracking and spalling; cracking; cracking due to expansion; loss of bond and loss of material (spalling, scaling); cracks and distortion; increase in porosity and permeability; loss of strength; loss of mechanical function; loss of sealing; and reduction of concrete anchor capacity. The LRA also states that the AMP implements the requirements of 10 CFR 50.65 (Maintenance Rule) consistent with the guidance of NUMARC 93-01, Revision 2, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," and RG 1.160, Revision 2, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," and provides inspection guidelines and walkdown checklists for structural steel, roof systems, reinforced concrete, masonry walls, and metal siding. The LRA further states that electrical duct banks and manholes, valve pits, access vaults, and structural supports are inspected as part of the AMP. The scope of the AMP includes masonry walls and water-control structures, since STP has committed to RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants." Settlement and heave movements are monitored for each major structure using benchmarks, and geotechnical monitoring techniques monitor settlement of structures. Groundwater is monitored for pH, excessive chlorides, and sulfates with at least two samples obtained every 5 years.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.S6. For the "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

The "preventive actions" program element in GALL Report AMP XI.S6 recommends that if ASTM A325, ASTM F1852, or ASTM A490 bolts are used, preventive actions in Section 2 of RCSC "Specification for Structural Joints Using ASTM A325 or A490 Bolts" should be addressed. However, during its audit, the staff found that the applicant's Structures Monitoring Program is not consistent with these statements because the applicant did not address the use of ASTM A325, ASTM F1852, or ASTM A490 bolts in the LRA, and it did not state if preventive actions in Section 2 of "Specification for Structural Joints Using ASTM A325 or A490 Bolts" will be used if these bolts are present. By letter dated August 15, 2011, the staff issued RAI B2.1.32-1 requesting that the applicant explain how the preventive actions discussed in Section 2 of RCSC "Specification for Structural Joints Using ASTM A325 or A490 Bolts" are addressed or why preventive actions are unnecessary.

In its response dated October 10, 2011, the applicant stated that plant procedures require that "only new bolts, nuts, and washers shall be used in bolted connections. Bolts, nuts, and washers shall be in good condition and not corroded, damaged, or dirty." The applicant further stated that plant procedures will be enhanced to include the preventive actions recommended in Section 2 of RCSC "Specification for Structural Joints Using ASTM A325 or A490 Bolts" for ASTM A325, ASTM F1852, or ASTM A490 bolts.

The staff finds the applicant's response acceptable because the applicant has committed (Commitment No. 25) to enhance plant procedures to specify the preventive actions for storage, protection, and lubricants, recommended in Section 2 of the RCSC publication "Specification for Structural Joints Using ASTM A325 or A490 Bolts" for ASTM A325, ASTM F1852 or ASTM A490 bolts. The staff's concern described in RAI B2.1.32-1 is resolved.

In addition, by letter dated December 6, 2011, the staff issued RAI B2.1.7-3 requesting that the applicant provide additional information to demonstrate that all in-scope high-strength structural bolts with greater than 1-inch nominal diameter have been completely removed from a localized corrosive environment and are not at risk of being exposed to a corrosive environment during the period of extended operation or update the program to include volumetric examinations comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category BG-1.

In its response dated January 5, 2012, the applicant stated that LRA Appendix B2.1.29 provides requirements for inservice inspection of safety-related component support bolting, and Appendix B2.1.32 provides requirements for inspection of structural bolting. The applicant also stated that the Structures Monitoring Program has been revised to supplement the visual inspection of high-strength bolts with volumetric examinations, in accordance with ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, of a representative sample. The applicant further stated that a representative sample size is 20 percent, with a maximum of 25 per unit, of high-strength bolts greater than 1-inch nominal diameter and with actual yield strength greater than or equal to 150 ksi. The representative sample will be selected from bolts most susceptible to SCC based on bolts in a susceptible environment. The staff's evaluation of the response to RAI B2.1.7-3 is documented in Section 3.0.3.2.5.

The staff finds the applicant's supplement to the Structures Monitoring Program to perform volumetric examinations on 20 percent of high-strength bolts, with a maximum of 25 bolts per unit, to be an acceptable approach because the applicant does not use lubricants that contribute to SCC, the high-strength bolts are located in areas that are not generally corrosive (only localized corrosive environments may exist), volumetric testing will be done on bolts in the most susceptible areas, and STP does not have any plant-specific experience with SCC of high-strength bolts.

The "parameters monitored or inspected" program element in GALL Report AMP XI.S6 recommends that, for inaccessible, below-grade, concrete structural elements at plants with non-aggressive groundwater, the acceptability of inaccessible areas should be evaluated when conditions exist in accessible areas that could indicate the presence of degradation in the inaccessible areas, and representative samples of exposed portions of below-grade concrete should be examined when excavated for any reason. The GALL Report also notes that, for plants with aggressive groundwater, or where concrete elements have experienced degradation, a plant-specific AMP that accounts for the extent of degradation experienced should be implemented to manage concrete aging during the period of extended operation. However, during its audit, the staff found that the applicant's Structures Monitoring Program is not consistent with these statements because the AMP does not provide historical results (including seasonal variations) to demonstrate that the groundwater is either aggressive or non-aggressive or that when below-grade concrete is excavated for any reason, opportunistic inspections of the exposed portions of the below-grade concrete will be performed. By letter dated August 15, 2011, the staff issued RAI B2.1.32-4 requesting that the applicant do the following:

- provide historical results, including seasonal variations, for groundwater chemistry (i.e., pH, sulfates, and chlorides) to demonstrate that the groundwater is either aggressive or non-aggressive
- if historical results indicate that the groundwater is considered to be non-aggressive, demonstrate that opportunistic inspections of exposed portions of below-grade concrete, when excavated for any reason, will be performed under the Structures Monitoring Program, or explain why the inspections are not needed
- if historical results indicate that the groundwater is aggressive, or where accessible concrete structural elements have experienced degradation, identify the plant-specific program that will be used to manage aging of these structures, or explain why the existing programs are adequate

In its response dated October 18, 2011, the applicant stated that samples taken in 1989 and 1990 indicate the site groundwater is non-aggressive. Direct measurements of chloride and sulfate levels have not been routinely taken; therefore, seasonal variances and current groundwater insights cannot be determined. The applicant further stated that operating experience has not identified any degradation of structures that would be attributable to aggressive groundwater. The applicant also stated that to validate that groundwater remains non-aggressive, site groundwater will be analyzed for pH, sulfates, and chlorides in samples taken at multiple locations around the site every 3 months for at least 24 consecutive months, beginning no later than September 2012. If the results of the 24-month sampling plan identify that the groundwater is aggressive or it is identified that accessible concrete structural elements have experienced degradation, an evaluation will be performed to determine the appropriate actions necessary to assure that the affected structures will continue to perform their intended functions. This may include increased visual inspections or other examination techniques. The applicant further stated that opportunistic inspections of exposed portions of the below-grade concrete, when excavated for any reason, will be performed using AMP B2.1.32, Structures Monitoring Program, which includes water-control structures.

The staff finds the applicant's response acceptable because operating experience has not identified any degradation of structures that would be attributable to aggressive groundwater, and the applicant has committed to enhance the Structures Monitoring Program procedures to include opportunistic inspection of exposed portions of the below-grade concrete, when excavated for any reason. The procedures will also be enhanced to require an evaluation should groundwater be determined to be aggressive or inspections of accessible concrete structural elements identify degradation. The evaluation will be performed to determine the appropriate actions, which may include visual inspections or other examination techniques, to assure that the affected structures will continue to perform their intended function (Commitment No. 25). In addition, the applicant has made a new commitment (Commitment No. 37), in response to RAI B2.1.32-4, to take groundwater samples at multiple locations around the site every 3 months for at least 24 consecutive months. The samples will be analyzed for pH, sulfates, and chlorides, beginning no later than September 2012. By letter dated October 28, 2013, the applicant informed the NRC that Commitment No. 37 had been completed. After the initial samples, the applicant will continue to sample the groundwater on a 5-year frequency, per the recommendations in the GALL Report (see Enhancement 2 below). Therefore, the staff's concern described in RAI B2.1.32-4 is resolved.

The "detection of aging effects" program element in GALL Report AMP XI.S6 recommends that all structures within the scope of license renewal should be monitored on a frequency not to exceed 5 years. However, the GALL Report also recognizes that some structures of lower safety significance—which are also subjected to benign environmental conditions—may be monitored at an interval exceeding 5 years; however, they should be identified and listed, together with their operating experience. During its audit, the staff found that the applicant's Structures Monitoring Program is not consistent with this statement because the AMP states that inspection intervals are selected to ensure that aging degradation will be detected and quantified before there is a loss of intended functions and that inspections are scheduled so that all accessible areas of both units are inspected every 10 years. Therefore, by letter dated August 15, 2011, the staff issued RAI B2.1.32-2 requesting that the applicant identify the structures and masonry walls that will be inspected with an inspection interval greater than 5 years and provide a technical justification, including the environments the structures are exposed to and a summary of past degradation, for the longer inspection interval.

In its response dated October 10, 2011, the applicant stated that ACI 349.3R, Table 6.1, recommends inspection intervals of 5 years for some components and 10 years for other components. The applicant further stated that, prior to entering the period of extended operation, the program will be enhanced to fully comply with the recommended frequencies from ACI 349.3R, Table 6.1 (Commitment No. 25).

The staff finds the applicant's response acceptable because it aligns the applicant's inspection frequency with the guidance in the industry standard, ACI 349.3R. This document identifies a 5-year inspection interval, consistent with the GALL Report recommendation, except for structures in a controlled interior environment, which may be inspected on a 10-year frequency. The staff finds this acceptable because the applicant does not have any operating experience that would indicate a 10-year inspection interval is inadequate for benign interior environments, and all other locations will be inspected on the GALL Report recommended 5-year interval. The staff's concern described in RAI B2.1.32-2 is resolved.

The "acceptance criteria" program element in GALL Report AMP XI.S6 recommends that ACI 349.3R-96 provides an acceptable basis for developing acceptance criteria for concrete structures and that applicants who are not committed to ACI 349.3R-96 and elect to use plant-specific criteria for concrete structures should describe the criteria and provide a technical basis for deviations from those listed in ACI 349.3R-96. However, during its audit, the staff found that the applicant's Structures Monitoring Program is not consistent with these statements because the AMP states that if inspections identify any areas having significant aging effects, notifications are made to determine the appropriate corrective action using categories of "acceptable," "acceptable with degraded condition," and "unacceptable." It is unclear to the staff whether the applicant is using ACI 349.3R-96 as the basis to establish the aging classifications, or if some other basis is used, and what criteria are used to categorize an SSC as having an "acceptable," "acceptable with degraded condition," or "unacceptable" classification of aging. By letter dated August 15, 2011, the staff issued RAI B2.1.32-3 requesting that the applicant provide the quantitative acceptance criteria for the Structures Monitoring Program and, if the quantitative acceptance criteria deviate from those discussed in ACI 349.3R-96, provide technical justification for the differences. The staff also asked that if the applicant will add quantitative acceptance criteria to the AMP as an enhancement, the applicant should provide plans and a schedule to conduct a baseline inspection using the quantitative acceptance criteria prior to the period of extended operation.

In its response dated October 10, 2011, the applicant stated that the Structures Monitoring Program, which includes inspection of water-control structures, provides checklists that identify the parameters to be monitored. The procedure requires that structural deficiencies be quantitatively described. The applicant also stated that it has evaluated all deficiencies identified to date. None of the deficiencies identified were noted as being greater in size than a hairline crack, and all are determined to not have any impact on the capability of the structure to perform its intended function. Each identified deficiency falls into the first-tier categorization, as specified in ACI 349.3R-96. The applicant stated that plant procedures will be enhanced before the next inspection period to provide inspection criteria and reference both ACI 349.3R-96 and ACI 201.1R-68 (Commitment No. 25). The applicant further stated that since all deficiencies have been evaluated and found not to exceed the quantitative acceptance criteria for first-tier categorization, a new baseline inspection is not required.

The staff finds the applicant's response acceptable because the applicant committed to enhance the Structures Monitoring Program to specify ACI 349.3R-96 and ACI 201.1R-68 as the basis for defining quantitative acceptance criteria, per the recommendations in the GALL Report. The staff's concern described in RAI B2.1.32-3 is resolved.

The staff also reviewed the portions of the "parameters monitored or inspected" and "detection of aging effects" program elements associated with enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B2.1.32 states an enhancement to the "parameters monitored or inspected" program element. In this enhancement, the applicant stated that the AMP procedures will be enhanced to specify inspections of seismic gaps, caulking and sealants, duct banks and manholes, valve pits and access vaults, doors, electrical conduits, raceways, cable trays, electrical cabinets and enclosures, and associated anchorage. The staff reviewed this enhancement against the corresponding element in GALL Report AMP XI.S6 and finds it acceptable because, when implemented, it will add clarification to the component types to be monitored during the period of extended operation. This enhancement brings the "parameters monitored or inspected" program element into alignment with the "parameters monitored or inspected" program element provided in GALL Report AMP XI.S6.

Enhancement 2. LRA Section B2.1.32 states an enhancement to the “parameters monitored or inspected” program element. In this enhancement, the applicant stated that plant procedures will be enhanced to monitor at least two groundwater samples every 5 years for pH, sulfates, and chlorides. The staff reviewed this enhancement against the corresponding element in GALL Report AMP XI.S6 and finds it acceptable because, when implemented, it will bring the groundwater sampling interval into alignment with the “parameters monitored or inspected” program element provided in GALL Report AMP XI.S6.

Enhancement 3. LRA Section B2.1.32 states an enhancement to the “detection of aging effects” program element. In this enhancement, the applicant stated that the AMP procedure will be enhanced to specify inspection intervals so that all accessible areas of both units are inspected every 10 years. The staff reviewed this enhancement against the corresponding element in GALL Report AMP XI.S6 and finds it unacceptable because the GALL Report, Revision 2, recommends that all structures within the scope of license renewal should be monitored on a frequency not to exceed 5 years. To address this concern, the staff issued RAI B2.1.32-2, which was discussed and resolved above.

Enhancement 4. LRA Section B2.1.32 states an enhancement to the “detection of aging effects” program element. In this enhancement, the applicant stated that the AMP procedure will be enhanced to specify inspector qualifications in accordance with ACI 349.3R-96. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds it acceptable because, when it is implemented, it will bring the inspector qualification requirements into alignment with the “parameters monitored or inspected” program element provided in GALL Report AMP XI.S6.

Summary. Based on its audit, and review of the applicant’s Structures Monitoring Program and of the applicant’s responses to RAIs B2.1.32-1, B2.1.32-2, B2.1.32-3, and B2.1.32-4, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.S6. In addition, the staff reviewed the enhancements associated with “parameters monitored or inspected” and “detection of aging effects” program elements and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.32 summarizes operating experience related to the Structures Monitoring Program. A review of inspection documents shows that the Structures Monitoring Program uses the CAP module of the site Oracle database system to track industry technical issues with database entries in the form of condition reports. Any issue that potentially affects plant safety, design bases, or otherwise requires a documented response or potential corrective action is tracked in the database. A baseline walkdown inspection was initiated in 1997, with results indicating that all structures were found to be in an acceptable condition except the Unit 1 fuel handling building (room 011), which had significant water leakage resulting in corrosion of structural steel columns that were then recoated. This area has been periodically inspected to confirm that the water level was being adequately controlled, and structural coatings have been reapplied to control corrosion.

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 evaluated and incorporated 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 RAIs, as discussed below.

During its walkdown with plant personnel, the staff noted that there was essentially no leakage from the spent fuel pool leak chase channels, and visual examinations of the exterior wall of the spent fuel pool as well as the underside of the spent fuel pool indicated no signs of leakage from the spent fuel pool. It was unclear to the staff whether the absence of leakage from the leak chase channels is representative of no leakage occurring or if the leak chase channels are clogged. If the channels are clogged, leakage could accumulate behind the liner and eventually migrate through the concrete, possibly causing degradation of the reinforced concrete. By letter dated August 15, 2011, the staff issued RAI B2.1.32-5 requesting that the applicant discuss any actions taken to ensure that the leak chase drainage system remains free and clear; describe how it will be confirmed that the leak chase drainage system remains free and clear during the period of extended operation (e.g., boroscope inspections of leak chase channels); and if the confirmation involves actively inspecting or cleaning the system, provide the frequency of the action and a justification for the proposed frequency.

In its response dated October 10, 2011, the applicant stated that the spent fuel pool tell-tale drains are checked each shift by a Plant Operator, and results are logged in the Mechanical Auxiliary Building Logsheets. The spent fuel pool leak chase drainage system has been monitored since startup of both units, and none of the spent fuel pool tell-tale drains have a history of boric acid residue buildup; however, there has been some boric acid residue buildup at the tell-tale drains for the transfer canal in Unit 1.

The applicant further stated that to ensure the spent fuel pool and transfer canal tell-tale drains remain free and clear through the period of extended operation, preventive maintenance activities will be developed to inspect the leak chase drainage system. The periodic inspection will include internal visual inspection of the accessible sections of the tell-tale drain lines. Based on the current condition of the spent fuel pool tell-tale drains, inspections will be performed at an initial inspection frequency of every 5 years. The applicant stated that the Preventive Maintenance Program has a continuous optimization process. Adjustments to the inspection activity frequency may be made based on as-found conditions to ensure an optimum frequency is maintained.

The staff finds the applicant’s response acceptable because the plant-specific operating experience has shown no indications of spent fuel pool leakage outside the leak chase system (e.g., through-wall leakage on the walls or floor), and the applicant has committed (Commitment No. 25) to enhance the Structures Monitoring Program procedures to require the performance of a periodic visual inspection of the accessible sections of the spent fuel pool and transfer canal tell-tale drain lines for blockage every 5 years, with the first inspection being performed within the 5 years before entering the period of extended operation. This inspection, along with continued visual inspections of the spent fuel pool and the surrounding concrete, provides assurance that any future leakage will be captured within the leak chase system, or through-wall leakage will be identified before significant degradation occurs. The staff’s concern described in RAI B2.1.32-5 is resolved.

During its walkdown with plant personnel, the staff noted that groundwater had accumulated to a depth of a few feet in room 011 between the Unit 2 fuel handling building and the Unit 2 reactor containment building. The applicant noted that no criteria exist relative to when the water is removed and that the visible concrete surfaces in this area are not routinely inspected. Since it was noted in the LRA that the aggregate materials used in the concrete mixtures were potentially reactive, it was unclear to the staff whether the standing water has resulted in concrete degradation or would lead to degradation during the period of extended operation. By letter dated August 15, 2011, the staff issued RAI B2.1.32-6 requesting that the applicant do the following:

- explain where the water is coming from and provide justification for this conclusion
- discuss any actions taken to address the accumulation of standing water between the fuel handling building and the Unit 2 containment (e.g., increased visual inspections, crack mapping)
- provide any plans to develop criteria related to when the standing water is removed and how the surfaces exposed to the standing water will be managed for aging during the period of extended operation (e.g., visual inspections, crack mapping, concrete core bores) and provide technical justification that these actions will be adequate to manage aging
- if similar conditions exist in Unit 1, provide the above information for both units and a discussion of any differences in aging management approaches

In its response dated October 10, 2011, the applicant stated that the water between the Unit 2 fuel handling building and the Unit 2 reactor containment building in room 011 is located at the fuel handling building base mat, elevation −29 ft. Groundwater around the site is at approximately elevation +16 ft. Water stops are installed between the two buildings to prevent groundwater intrusion. However, groundwater imposes a head of approximately 40 ft and seeps into this area at a slow rate. Recent water samples of the wells, located due east between the two units, indicated a pH of 7.6. The applicant stated that recent groundwater samples in room 011 indicated a pH of 8.7, which is within the expected variability of other groundwater samples and confirms that the water in room 011 is from groundwater intrusion.

The applicant also discussed the actions taken to address the accumulation of standing water between the fuel handling building and reactor containment building. The applicant stated that a water sample from room 011 was tested on August 8, 2011, for pH, sulfates, and chlorides. Test results indicated a pH of 8.76, a sulfate concentration of 13.7 ppm, and a chloride concentration of 25.8 ppm, indicating that the water is non-aggressive to concrete. The applicant further stated that the water will be removed and the concrete surface will be inspected using the guidance in ACI 201.1R and ACI 349.3R and that the inspection will be documented in the CAP.

In regards to developing criteria related to when the standing water is removed and how surfaces exposed to the standing water will be managed for aging during the period of extended operation, the applicant stated that the areas exposed to standing groundwater meet the licensed Code requirements for exposure to water. The applicant further stated that the principal concern with standing water is the increased potential for corrosion of the embedded reinforcement. Rust stains would be visible at the surface if mild corrosion were to occur, and if more severe corrosion occurs, spalled concrete could result. The applicant stated that these symptoms would be observable during visual inspections and that the concrete surfaces would be inspected using the guidance in ACI 201.1R and ACI 349.3R.

The applicant stated that conditions similar to those described in Unit 2 do not exist in Unit 1. A drain installed in Unit 1 directs water in this area to the tendon gallery. The area was drained and visually inspected. No aging effects have been identified in this area. Both units will follow similar aging management approaches.

The staff reviewed the applicant's response and identified several issues that required clarification. Therefore, the staff participated in a teleconference with the applicant on November 17, 2011, to discuss the response. Based on the discussion, the applicant supplemented its response by letter dated December 7, 2011. In the supplement, the applicant stated that the Unit 2 area was scheduled to be drained in January 2012, with completion of the concrete surface inspection shortly thereafter. Any additional water that accumulates in that area on either unit will be removed before the ASME Code Section XI, Subsection IWL containment inspection, which is done every 5 years. The applicant further clarified that future inspections of the containment structure will follow the frequency and guidance of the ASME Code Section XI, Subsection IWL Program, while inspections of the fuel handling building will follow the frequency and guidance of the Structures Monitoring Program. These programs follow the guidance of ACI 349.3R and ACI 201.1R, which recommend a 5-year inspection frequency for structures continuously exposed to fluids.

The staff reviewed the applicant's response and the associated supplement, and noted that the groundwater is not aggressive to concrete. On August 8, 2011, a water sample from room 011 was tested for pH, sulfates, and chlorides with results of 8.76, 13.7 ppm, and 25.8 ppm, respectively. In accordance with the GALL Report, water that has a pH less than 5.5, sulfates greater than 1,500 ppm, and chlorides greater than 500 ppm is considered aggressive. In addition, the staff noted that the applicant will drain this area before conducting appropriate visual inspections in accordance with the proper AMPs. The staff finds the applicant's response acceptable because the sample results do not indicate aggressive groundwater, the applicant has committed to monitor at least two groundwater samples every 5 years to confirm the water remains non-aggressive, the applicant will drain the water in Unit 2 every 5 years to conduct the appropriate GALL Report recommended visual inspections; and although the applicant used potentially reactive aggregates, no aging effects were identified during the visual inspections conducted in the equivalent area of Unit 1 after it was drained. The staff's concern described in RAI B2.1.32-6 is resolved.

Based on its audit and review of the application and review of the applicant's responses to RAIs B2.1.32-5 and RAI B2.1.32-6, the staff finds that the applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Appendix A provides the UFSAR supplement for the Structures Monitoring Program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the applicant committed (Commitment No. 25) to ongoing implementation of the existing Structures Monitoring Program for managing aging of applicable components during the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Structures Monitoring Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancement and confirmed that their implementation—through Commitment No. 25 prior to the period of extended operation—will make the AMP adequate to manage the applicable aging effects. 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).

3.0.3.2.27 RG 1.127, Inspection of Water-Control Structures with Nuclear Power Plants

Summary of Technical Information in the Application. LRA Section B2.1.33, as amended by Annual Updates, including supplements of 2011 and 2016, describes the existing RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants Program," as consistent, with an exception and enhancements, with GALL Report AMP XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants." The LRA states that the AMP manages cracking, loss of bond, loss of material (spalling, scaling), cracking due to expansion, increase in porosity and permeability, loss of strength, and loss of form by performing inspection and surveillance activities for all water control structures associated with the ECW systems. The AMP is committed to conform to the intent of RG 1.127 with respect to the essential cooling water pond (ECP), the ECP intake structure, and the ECP discharge structure. The AMP performs periodic monitoring of the ECP (ultimate heat sink) hydraulic and structural condition, which includes evaluation of erosion-inhibiting structures, conditions of benchmarks and piezometers, and measuring the ECP volume as indicative of any sediment accumulation. In addition, the AMP conducts a seepage rate evaluation of the ECP every 5 years.

In annual updates, submitted by letters dated November 30, 2011 (ADAMS Accession No. ML11335A140), and September 28, 2016 (supplement to 2016 Annual Update (ADAMS Accession No. ML16285A406)), the applicant amended its program with enhancements to the "parameters monitored or inspected" program element, and enhancements and an exception to the "detection of aging effects" program element.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.S7. For the "preventive actions," "parameters monitored or inspected," and "acceptance criteria" program elements, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

Preventive Actions. The "preventive actions" program element in GALL Report AMP XI.S7 recommends that if ASTM A325, ASTM F1852, or ASTM A490 bolts are used, preventive actions in Section 2 of "Specification for Structural Joints Using ASTM A325 or A490 Bolts" should be addressed. However, during its audit, the staff found that the applicant's AMP is not consistent with these statements because the applicant did not address the use of ASTM A325, ASTM F1852, or ASTM A490 bolts in the LRA, and it did not state if preventive actions in Section 2 of "Specification for Structural Joints Using ASTM A325 or A490 Bolts" will be used if these bolts are present. By letter dated August 15, 2011, the staff issued RAI B2.1.32-1 requesting that the applicant explain how the preventive actions discussed in Section 2 of "Specification for Structural Joints Using ASTM A325 or A490 Bolts" are addressed or why preventive actions are unnecessary.

In its response dated October 10, 2011, the applicant stated that plant procedures require that "only new bolts, nuts, and washers shall be used in bolted connections. Bolts, nuts, and washers shall be in good condition and not corroded, damaged, or dirty." The applicant further stated that plant procedures will be enhanced to include the preventive actions recommended in Section 2 of the RCSC "Specification for Structural Joints Using ASTM A325 or A490 Bolts" for ASTM A325, ASTM F1852, or ASTM A490 bolts.

The staff finds the applicant's response acceptable because the applicant committed (Commitment No. 26) to enhance plant procedures to specify the preventive actions for storage, protection, and lubricants, recommended in Section 2 of the RCSC publication "Specification for Structural Joints Using ASTM A325 or A490 Bolts" for ASTM A325, ASTM F1852, and ASTM A490 bolts. The staff's concern described in RAI B2.1.32-1 is resolved.

Parameters Monitored or Inspected. The "parameters monitored or inspected" program element in GALL Report AMP XI.S7 recommends that for inaccessible, below-grade, concrete structural elements at plants with non-aggressive groundwater, the acceptability of inaccessible areas should be evaluated when conditions exist in accessible areas that could indicate the presence of degradation in the inaccessible areas, and representative samples of exposed portions of below-grade concrete should be examined when excavated for any reason. The GALL Report also notes that for plants with aggressive groundwater, or where concrete elements have experienced degradation, a plant-specific AMP that accounts for the extent of degradation experienced should be implemented to manage concrete aging during the period of extended operation. However, during its audit, the staff found that the applicant's AMP is not consistent with these statements because the AMP does not provide historical results (including seasonal variations) to demonstrate that the groundwater is either aggressive or non-aggressive or that when below-grade concrete is excavated for any reason, opportunistic inspections of the exposed portions of the below-grade concrete will be performed. By letter dated August 15, 2011, the staff issued RAI B2.1.32-4 requesting that the applicant do the following:

- provide historical results, including seasonal variations, for groundwater chemistry (i.e., pH, sulfates, and chlorides) to demonstrate that the groundwater is either aggressive or non-aggressive
- if historical results indicate that the groundwater is considered to be non-aggressive, demonstrate that opportunistic inspections of exposed portions of below-grade concrete, when excavated for any reason, will be performed under both the Structures Monitoring Program and the RG 1.127, or explain why the inspections are not needed
- if historical results indicate that the groundwater is aggressive, or where accessible concrete structural elements have experienced degradation, identify the plant-specific program that will be used to manage aging of these structures, or explain why the existing programs are adequate

In its response dated October 18, 2011, the applicant stated that samples taken in 1989 and 1990 indicate the site groundwater is non-aggressive. Direct measurements of chloride and sulfate levels have not been routinely taken; therefore, seasonal variances and current groundwater insights cannot be determined. The applicant further stated that operating experience has not identified any degradation of structures that would be attributable to aggressive groundwater. The applicant also stated that to validate that groundwater remains non-aggressive, site groundwater will be analyzed for pH, sulfates, and chlorides in samples taken at multiple locations around the site every 3 months for at least 24 consecutive months, beginning no later than September 2012. If the results of the 24-month sampling plan identify that the groundwater is aggressive or it is identified that accessible concrete structural elements have experienced degradation, an evaluation will be performed to determine the appropriate actions necessary to assure that the affected structures will continue to perform their intended functions. This may include increased visual inspections or other examination techniques. The applicant further stated that opportunistic inspections of exposed portions of the below-grade concrete, when excavated for any reason, will be performed using AMP B2.1.32, Structures Monitoring Program, which includes water-control structures.

The staff finds the applicant’s response acceptable because operating experience has not identified any degradation of structures that would be attributable to aggressive groundwater, and the applicant committed to enhance the Structures Monitoring Program procedures to include opportunistic inspection of exposed portions of the below-grade concrete, when excavated for any reason. The procedures will also be enhanced to require an evaluation should groundwater be determined to be aggressive or inspections of accessible concrete structural elements identify degradation. The evaluation will be performed to determine the appropriate actions, which may include visual inspections or other examination techniques, to assure that the affected structures will continue to perform their intended function (Commitment No. 25). In addition, the applicant made a new commitment (Commitment No. 37), in response to RAI B2.1.32-4, to take groundwater samples at multiple locations around the site every 3 months for at least 24 consecutive months. The samples will be analyzed for pH, sulfates, and chlorides, beginning no later than September 2012. After the initial samples, the applicant will continue to sample the groundwater on a 5-year frequency, per the recommendations in the GALL Report. Therefore, the staff’s concern described in RAI B2.1.32-4 is resolved.

The staff also reviewed the portions of the “parameters monitored or inspected” program element associated with enhancements included in the supplement to the 2016 Annual Update, dated September 28, 2016, to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff’s evaluation of this enhancement follows.

Acceptance Criteria. The “acceptance criteria” program element in GALL Report AMP XI.S7 recommends that ACI 349.3R-96 provides an acceptable basis for developing acceptance criteria for concrete structures and that applicants who are not committed to ACI 349.3R-96 and elect to use plant-specific criteria for concrete structures should describe the criteria and provide a technical basis for deviations from those listed in ACI 349.3R-96. However, during its audit, the staff found that the applicant’s RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants AMP is not consistent with these statements because the AMP states that if inspections identify any areas having significant aging effects, notifications are made to determine the appropriate corrective action using categories of “acceptable,” “acceptable with degraded condition,” and “unacceptable.” It was unclear to the staff whether the applicant is using ACI 349.3R-96 as the basis to establish the aging classifications or if some other basis is used, and it is unclear what criteria are used to categorize an SSC as having an “acceptable,” “acceptable with degraded condition,” or “unacceptable” classification of aging. By letter dated August 15, 2011, the staff issued RAI B2.1.32-3 requesting that the applicant provide the quantitative acceptance criteria for the RG 1.127 Inspection of Water-Control Structures Inspection Program, and if the quantitative acceptance criteria deviate from those discussed in ACI 349.3R-96, provide technical justification for the differences. The staff also asked that, if quantitative acceptance criteria will be added to the AMP as an enhancement, the applicant provide plans and a schedule to conduct a baseline inspection using the quantitative acceptance criteria prior to the period of extended operation.

In its response dated October 10, 2011, the applicant stated that the Structures Monitoring Program, which includes inspection of water-control structures, provides checklists that identify the parameters to be monitored. The procedure requires structural deficiencies be quantitatively described. All deficiencies identified to date have been evaluated. None of the deficiencies identified were noted as being greater in size than a hairline crack, and all are determined to not have any impact on the capability of the structure to perform its intended function. Each identified deficiency falls into the first-tier categorization, as specified in ACI 349.3R-96. Plant procedures will be enhanced before the next inspection period to provide inspection criteria and reference both ACI 349.3R-96 and ACI 201.1R-68 (Commitment No. 26). The applicant further stated that since all deficiencies have been evaluated and found not to exceed the quantitative acceptance criteria for first-tier categorization, a new baseline inspection is not required.

The staff finds the applicant's response acceptable because the applicant committed to enhance the Structures Monitoring Program, which includes the RG 1.127 Program, to specify ACI 349.3R-96 and ACI 201.1R-68 as the basis for defining quantitative acceptance criteria. The staff's concern described in RAI B2.1.32-3 is resolved.

Enhancement 1. LRA Section B2.1.33, as amended by supplemental letter to the 2016 Annual Update, dated September 28, 2016, states an enhancement to the "parameters monitored or inspected" program element. In this enhancement, the applicant stated that procedures will be enhanced to (1) require monitoring of the essential cooling pond (ECP) for sediment accumulation, (2) require evaluation of essential cooling pond seepage rate, and (3) require visual inspection of the essential cooling pond, including checking the embankment lining for signs of erosion or loss of form of slope protection features.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and found it acceptable because, when implemented under Commitment No. 26, it will align the "parameters monitored or inspected" program element for the ECP with that of the GALL Report AMP XI.S7 and RG 1.127. The guidance in RG 1.127 discusses monitoring sediment accumulation and seepage, and using visual inspections to monitor embankments for signs of distress.

Detection of Aging Effects. The staff also reviewed the portions of the "detection of aging effects" program element associated with the exception and enhancements included in the annual updates to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of the exception and enhancements follows.

Exception. LRA Section B2.1.33, as amended by the 2011 Annual Update, dated November 30, 2011, states an exception to the "detection of aging effects" program element. In this exception, the applicant stated that the interval for sediment monitoring of the ECP was 10 years. The applicant explained that the makeup sources (a well water system – primary, and the Main Cooling Reservoir – secondary) for the ECP are relatively free of sediment and that sediment levels were measured yearly from 1987 to 1997 with no measurable accumulation of sediment. The sediment levels were also measured in 2002 and 2009 with the same results. Finally, the applicant stated that extending the interval for sediment surveys from 5 to 10 years will have no effect on the ECP design function.

The staff reviewed this exception against the corresponding program element in the GALL Report AMP XI.S7 and noted that RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," which the plant conforms to, limits inspection intervals to 5 years if the results of previous inspections justify the extension. The staff noted that, in the case of sedimentation, the RG states: "the reservoir and drainage area should be examined for excessive sedimentation or recent developments in the drainage basin that could cause a sudden increase in sediment load, thereby reducing the reservoir capacity with attendant increase in maximum outflow and maximum pool elevation."

The staff then reviewed Section 9.2.5.4, "Tests and Inspections," of the UFSAR and verified that the change in frequency of soundings (inspections to measure depth of water and, therefore, the change in sedimentation) to not less than once every 10 years was based on historical sounding records terminating in 2009. Furthermore, the staff verified that the ECP is a robust man-made pond having no canal ingress that potentially could transport sediment to the pond and is capable of withstanding seismic and hydraulic forces as detailed in Sections 2.4.8, "Cooling Water Canals and Reservoirs," 2.5.6.1.2, "Essential Cooling Pond," and 9.2.5, "Ultimate Heat Sink," respectively, of the UFSAR. The review of the UFSAR also indicates when the sediment accumulation in the pond is such that it appears the level of accumulation will exceed 5 percent of the impoundment volume before that allowable limit is reached, corrective actions will be initiated to remove the sediment deposition during the life of the plant.

Therefore, the staff finds that increasing the interval of soundings from 5 to 10 years acceptable because the applicant experienced no sediment collection in the ECP, as witnessed in applicant documents examined (ADAMS Accession No. ML112800109), because the makeup sources to the ECP do not provide a likely path for sediment to enter the pond, because of the robustness of the pond in case of local accumulation of sedimentation, and because the existence of a corrective action to remove any accumulated sedimentation up to 5 percent of the impoundment volume for the life of the plant, including the period of extended operation. Therefore, the 10-year sounding inspection interval is acceptable for monitoring sediment in the ECP pond.

Enhancement 2. LRA Section B2.1.33, as stated in the application and as amended by letter, dated September 28, 2016, supplementing the 2016 Annual Update, states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that procedures will be enhanced to specify inspections of the ECP and ECW intake and discharge structures at intervals not to exceed 5 years, or immediately following significant natural phenomena, and to require a seepage rate evaluation to be performed every 5 years.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and found it acceptable, because when it is implemented it will align the AMP inspection interval with the 5-year inspection interval recommended in GALL Report AMP XI.S7.

Enhancement 3. LRA Section B2.1.33, as updated by letter, dated September 28, 2016, supplementing the 2016 Annual Update, states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that procedures will be enhanced to specify that sediment monitoring will be performed using soundings.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and finds it acceptable because specific updates to plant procedures are essential for proper implementation of the GALL Report AMP XI.S7 recommendations for sediment monitoring through soundings. This method of data collection to assess storage capacities in reservoirs, drawdown, and volume of sediment accumulation is an industry standard and therefore acceptable.

Summary. Based on its audit of the applicant's RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, and review of the applicant's responses to RAIs B2.1.32-1, B2.1.32-3, and B2.1.32-4, and the applicant's annual updates of November 30, 2011, and a supplement to the 2016 Annual Update, dated September 28, 2016, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.S7. The staff also reviewed the exception associated with the "detection of aging effects" program element and its justification, and finds that the AMP with the exception is adequate to manage the applicable aging effects. In addition, the staff reviewed the enhancements associated with the "parameters monitored or inspected" and "detection of aging effects" program elements and finds that, when implemented, Commitment No. 26 will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.33 summarizes operating experience related to RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. A review of the inspection documents shows that the water control structures at STP, including the ECP and ECW intake and discharge structures have been subject to relatively few aging effects. All structures have been found to be in an acceptable condition and meet engineering functional requirements including performance, maintainability, and safety. The 1997 ECP inspection report indicated virtually no accumulation of sediment, and differential settlements of the intake and discharge structures were well within the allowable limit of ¾ inch. The report also indicated that deflections measured using benchmark elevations along buried ECW pipe routes were found to be within the allowable 1.5 inch, all ECP benchmarks and piezometers were found to be functional, and measurements were being taken as specified in the UFSAR. The report notes occurrences of shrinkage cracks running longitudinally along the soil cement and concrete paved exterior slopes of embankments. The report attributes the cracks to fluctuating moisture contents of the soil within and, therefore, did not indicate any signs of erosion. Finally, the LRA states that there were two minor instances of growing vegetation around the ECP slopes.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, 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 evaluated and incorporated 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" program element of the AMP states that the ECW intake and discharge structures have been subjected to relatively few aging effects, and inspections of these structures are conducted under the Structures Monitoring Program. The LRA includes an enhancement to the "detection of aging effects" program element, which states that the program will be enhanced to specify inspection at intervals not to exceed 5 years (except for the sounding inspections as discussed above). However, it does not clearly state that concrete structures below the water-line will be inspected on this frequency. It was unclear to the staff what procedures are used to conduct the visual inspections of these structures and at what frequency these inspections are performed. By letter dated August 15, 2011, the staff issued RAI B2.1.32-7 requesting that the applicant describe the procedure (e.g., drain the areas, use divers) and acceptance criteria for visual inspections of the ECW intake and discharge structures that are below the water-line and provide the frequency of inspection for these structures. If the frequency does not meet the recommendations in the GALL Report, the applicant was asked to provide justification for the inspection frequency.

In its response dated October 10, 2011, the applicant stated that the Structures Monitoring Program (B2.1.32) requires the inspection of submerged concrete structures. The ECW intake and discharge structures are dewatered and visually examined or, alternatively, inspected by divers, every third cycle. The inspection frequency of every third cycle is consistent with the 5-year interval recommended in the GALL Report. The applicant also stated that the Structures Monitoring Program, which includes the inspection of water-control structures, requires structural deficiencies to be quantitatively described. All deficiencies identified to date have been evaluated, and none were noted as being greater in size than a hairline crack, which fall into the first-tier categorization specified in ACI 349.3R-96.

The staff finds the applicant's response acceptable because the applicant's procedure to dewater and visually inspect the ECW intake and discharge structures or visually inspect using divers every third cycle (a cycle is 1.5 years), complies with the inspection method and 5-year frequency recommended in the GALL Report. The staff's concern described in RAI B2.1.32-7 is resolved.

Based on its audit and review of the application and review of the applicant's response to RAI B2.1.32-7, the staff finds that the applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Appendix A provides the UFSAR supplement for RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the applicant committed (Commitment No. 26) to ongoing implementation of the existing RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants Program for managing aging of applicable components during the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancement and confirmed that its implementation—through Commitment No. 26 prior to the period of extended operation—will make the AMP adequate to manage the applicable aging effects. 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).

3.0.3.2.28 Metal Fatigue of Reactor Coolant Pressure Boundary

Summary of Technical Information in the Application. LRA Section B.3.1 describes the existing Metal Fatigue of Reactor Coolant Pressure Boundary Program as consistent, with enhancements, with GALL Report AMP X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary."

The applicant stated that its program manages fatigue cracking caused by anticipated cyclic strains in metal components of the RCPB, and the program will ensure that actual plant experience remains bounded by the number of transients assumed in the design calculations or appropriate corrective measures maintain the design and licensing basis by other acceptable means. The applicant also stated that it will use the cycle-counting method and the cycle-based fatigue management method to monitor transient cycles and fatigue usage, and the program will review calculated usage factors and cycle counts to determine if corrective actions are required. The effects of the reactor coolant environment on component fatigue life will be assessed by the environmental impact on a sample of critical components identified in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," in accordance with guidance from NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," for carbon and low-alloy steels and NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels," for austenitic stainless steels.

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 found that, for the "scope of program" program element, sufficient information was not available for the staff to determine whether it was consistent with the corresponding program element of the GALL Report AMP. For the "corrective actions" program element, the staff also determined that additional clarification was needed, which resulted in the issuance of RAIs.

GALL Report AMP X.M1 recommends the evaluation of reactor water environment on fatigue life for a sample set of components, which should include the locations identified in NUREG/CR-6260 and additional plant-specific component locations in the RCPB if they may be more limiting. When reviewing the "scope of program" program element of applicant's program, the staff noted that the applicant did not address any additional component locations other than those from NUREG/CR-6260 for the evaluation of the effects of reactor water environment, as recommended in GALL Report AMP X.M1.

By letter dated August 15, 2011, the staff issued RAI B.3.1-5 requesting that the applicant justify that the plant-specific locations listed in LRA Table 4.3-8 for environmentally-assisted fatigue (EAF) analyses are 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 staff asked the applicant to clarify the locations that require an EAF analysis and explain the actions that will be taken for these additional locations.

In its response dated September 15, 2011, the applicant stated that no additional RCPB components were considered for inclusion in the EAF analyses beyond those assessed in LRA Table 4.3-8. The applicant also provided Commitment No. 34, which states that, prior to the period of extended operation, it will perform a review of design basis ASME Code Class 1 component fatigue evaluations to determine whether the NUREG/CR-6260-based components that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting components for the STP configuration. The applicant also stated that if it identifies more limiting components, it will evaluate the most limiting component for the effects of the reactor coolant environment on fatigue usage. If the limiting location consists of nickel alloy, the methodology for nickel alloy in NUREG/CR-6909, "Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials," will be used to perform the EAF calculation. Finally, the applicant stated that additional evaluations will be performed and managed through the Metal Fatigue of Reactor Coolant Pressure Boundary Program, in accordance with 10 CFR 54.21(c)(1)(iii).

The staff noted that the applicant's new commitment will be implemented as part of its Metal Fatigue of Reactor Coolant Pressure Boundary Program; however, the applicant did not include this as an enhancement to its program in LRA Section B3.1 and did not revise the UFSAR supplement in LRA Section A2.1. By letter dated October 11, 2011, the staff issued RAI B3.1-5a (followup) requesting that the applicant revise LRA Section B3.1 and LRA Section A2.1, consistent with the additional commitment discussed in the response to RAI B3.1-5.

In its response to RAI B3.1-5a (followup) dated November 21, 2011, the applicant revised LRA Sections A2.1 and B3.1 to be consistent with Commitment No. 34, as discussed in the response to RAI B3.1-5. The staff's review of this additional enhancement and of RAIs B3.1-5 and B3.1-5a (followup) are documented below in Enhancement 6.

The applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program is based on GALL Report AMP X.M1, which is limited to the use of cycle counting for cumulative usage factor (CUF) analyses. The staff noted that the use of cycle counting (tracking total cycles—such as thermal or transient cycles—experienced by a component against a limit or design total number of cycles) to manage crack growth of postulated or existing macroscopic flaws is not covered by GALL Report AMP X.M1. However, the applicant's LRA Section 4.3.2.11 credits its Metal Fatigue Program to manage the aging effects associated with the leak-before-break (LBB) TLAA and dispositioned it in accordance with 10 CFR 54.21(c)(1)(iii). The applicant expanded the use of cycle counting to the LBB TLAA, which is a non-CUF analysis, without including enhancements in the AMP or including them in the applicable licensing basis documents. By letters dated August 15, 2011, and October 11, 2011, the staff issued RAI B3.1-3 and RAI B3.1-3a (followup), asking the applicant to justify the use of cycle counting in the Metal Fatigue of Reactor Coolant Pressure Boundary Program for the LBB TLAA without an update to the applicable documents (e.g., TS, UFSAR, and cycle-counting procedure) and without the inclusion of enhancements to the Metal Fatigue of Reactor Coolant Pressure Boundary Program.

In its responses dated September 15, 2011; November 4, 2011; and November 21, 2011, the applicant stated that Commitment No. 30 in LRA Appendix A was updated to include the use of cycle-counting activities to ensure the fatigue crack growth analyses for LBB remain valid and associated corrective actions to be invoked if a component approaches the cycle-counting action limit. In addition, the "scope of program" program element of LRA Section B3.1 was revised to identify the increase in the scope of the program to ensure the fatigue crack growth analyses that support the LBB analyses remain valid by counting the transients used in the analyses. The applicant stated that LRA Section A2.1 was also revised to state that any reanalysis of a fatigue crack growth analysis will be consistent with or reconciled to the originally submitted analysis and will receive the same level of regulatory review as the original analysis.

The staff noted that this means that if a fatigue crack growth analysis previously required NRC review and approval then any revisions to that analysis would also require NRC review and approval. The applicant confirmed that the changes to the plant's cycle-counting procedure will be made consistent with enhancements provided in response to RAI B3.1-3, regarding the use of cycle-counting activities to ensure the fatigue crack growth analyses for LBB remain valid and associated corrective actions to be invoked if a component approaches the cycle-counting action limit. The staff's evaluation and resolution of RAI B3.1-3 and RAI B3.1-3a (followup) are documented below in Enhancement 7.

The staff also reviewed the portions of the "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria," and "corrective action" program elements associated with enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B3.1 states an enhancement to the "scope of program," and "monitoring and trending" program elements. The applicant stated that the scope of locations monitored by the Metal Fatigue of Reactor Coolant Pressure Boundary Program will be enhanced prior to the period of extended operation to include additional locations identified by the evaluation of ASME Code Section III fatigue analyses, locations necessary to ensure accurate calculations of fatigue, and the NUREG/CR-6260 locations for a newer-vintage Westinghouse Plant.

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP X.M1. The staff confirmed that LRA Section 4.3.4 provides the applicant's EAF evaluations for those RCPB components that correspond to the locations recommended for analysis in NUREG/CR-6260. These evaluations are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii). SER Section 4.3 documents the staff's evaluation of EAF.

Based on its review, the staff finds this enhancement acceptable because the inclusion of these sample locations from NUREG/CR-6260 to be evaluated for EAF, and locations identified by the applicant's ASME Code Section III fatigue analyses are consistent with the recommendations in GALL Report AMP X.M1.

Enhancement 2. LRA Section B3.1 states an enhancement to the "scope of program" and "parameters monitored or inspected" program elements. The applicant stated that it will enhance the scope of transients monitored by its Metal Fatigue of Reactor Coolant Pressure Boundary Program to include additional transients that contribute to fatigue usage factors identified by the evaluation of ASME Code Section III fatigue analyses.

The staff noted that the "parameters monitored or inspected" program element of GALL Report AMP X.M1 recommends monitoring all plant transients that cause cyclic strains, which are significant contributors to the fatigue usage factor. It also states that the number of plant transients that cause significant fatigue usage for each critical RCPB component is to be monitored. LRA Section 4.3.1 describes the assessment of the design basis transients that are applicable and that would need to be monitored during the period of extended operation. The staff noted that the applicant's enhancement will include those transients that were determined to be significant contributors to the fatigue usage factor that were not currently included in its program. The staff noted that the applicant's TLAA appropriately noted that there were additional transients that were determined to be significant contributors to the calculation of CUFs that are currently beyond the scope of design basis transients. SER Section 4.3.1

documents the staff's evaluation of the design basis transients that are applicable to the applicant's metal fatigue TLAAs that need to be monitored under the Metal Fatigue of Reactor Coolant Pressure Boundary Program.

Based on its review, the staff finds this enhancement acceptable because it will ensure that the applicant's cycle-counting activities are applied to all transients that cause cyclic strains that are significant contributors to the fatigue usage factors, consistent with the recommendations of the "scope of program" and "parameters monitored or inspected" program elements.

Enhancement 3. LRA Section B3.1 states an enhancement to the "detection of aging effects" program element. The applicant stated that it will enhance the procedures governing its Metal Fatigue of Reactor Coolant Pressure Boundary Program to determine the frequency of periodic reviews examining the results of the monitored cycle count and CUF data at least once per fuel cycle.

The "detection of aging effects" program element of GALL Report AMP X.M1 states that the program should provide for updates of the fatigue usage calculation on an as-needed basis if an allowable cycle limit is approached. The staff noted that the applicant's enhancement ensures that the program will be capable of identifying when the accrued number of cycles approaches the allowable limit or if the cumulative fatigue usage approaches the design limit of 1.0.

Based on its review, the staff finds the enhancement acceptable because the applicant's program, consistent with the recommendations of GALL Report AMP X.M1, has measures to ensure that fatigue usage calculations are updated, as needed, before the accrued cycles exceeding the allowable cycle limit; therefore, the design limit of 1.0 will not be exceeded or the analysis will not become invalid.

Enhancement 4. LRA Section B3.1 states an enhancement to the "preventive actions" and "acceptance criteria" program elements. The applicant stated that it will enhance the procedures for governing this program to include additional cycle count and fatigue usage action limits that will invoke appropriate corrective actions when a component approaches a cycle-count action limit or a fatigue usage factor action limit. Furthermore, the applicant stated that the action limits will permit completion of corrective actions before the design limits are exceeded. The applicant explained this by stating that corrective actions are initiated if the cycle count for any of the critical thermal or pressure transients is projected to reach the action limit defined in the program or the calculated CUF for any monitored location is projected to reach 1.0 within the following three fuel cycles. The staff reviewed this enhancement against the corresponding program elements in the GALL Report AMP X.M1.

The "acceptance criteria" program element of GALL Report AMP X.M1 states that the acceptance criterion is maintaining the cumulative fatigue usage below the design limit through the period of extended operation, with consideration of the reactor water environmental fatigue effects. The "preventive actions" program element of GALL Report AMP X.M1 states that the program prevents the analyses from becoming invalid by assuring that the fatigue usage resulting from actual operational transients does not exceed the design limit of 1.0, including environmental effects. The staff noted that the applicant's enhancement ensures that action limits will be established for those design transients used in the applicant's analyses, such that corrective actions will be taken to maintain the fatigue usage factors (including the effects of reactor water environment if applicable) below the design limit of 1.0 and ensure that the analyses remain valid.

Based on its review, the staff finds this enhancement acceptable because, consistent with the recommendation of GALL Report AMP X.M1, establishing action limits would allow corrective actions to be taken to maintain the fatigue usage factors, including environmental effect if applicable, below the design limit of 1.0 and ensures that the analyses remain valid during the period of extended operation.

Enhancement 5. LRA Section B3.1 contains an enhancement to the “corrective actions” program element. The applicant stated that it will enhance the procedures governing its Metal Fatigue of Reactor Coolant Pressure Boundary Program to include appropriate corrective actions to be invoked if a component approaches a cycle count or CUF action limit.

The “corrective actions” program element of GALL Report AMP 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 limit will not be exceeded during the period of extended operation. The enhancement of the applicant’s program indicates that if the CUF approaches 1.0, the program will have seven options as acceptable corrective actions to be taken to keep the CUF below its design limit of. The staff noted that Enhancement 4 discusses the applicant’s CUF action limits, which ensure that corrective actions are taken if the design limit of 1.0 is projected to be reached within the next three fuel cycles. The staff noted that four of the seven proposed corrective actions are in addition to the recommendations in GALL Report AMP X.M1.

It was not clear to the staff if these four additional options for corrective actions to prevent CUF or environmentally correct cumulative usage factor (CUF_{en}) from exceeding the design limit would be taken when the applicant’s action limit is reached or when the fatigue usage has approached 1.0. On April 4, 2011, the staff issued RAI 4.3.2.11-3 to clarify the "appropriate corrective actions" and "other acceptable means" statements.

In response to RAI 4.3.2.11-3, by letter dated May 12, 2011, the applicant amended this enhancement to include the following corrective action if a cycle-count action limit is reached:

> Review of fatigue crack growth and stability analyses support the leak before break exemptions and relief from the ASME [Code] Section XI flaw removal or inspection requirements to ensure that the analytical bases remain valid. Reanalysis of a fatigue crack growth analysis must be consistent with or reconciled to the originally submitted analysis and receive the same level of regulatory review as the original analysis.

The staff noted that the applicant is using its Metal Fatigue of Reactor Coolant Pressure Boundary Program to count the number of accrued cycles to ensure that these fatigue crack growth and stability analyses remain valid, as described below in Enhancement 7. Based on its review, the staff finds the applicant’s amendment to its enhancement of the “corrective actions” program element acceptable because the applicant’s program ensures these analyses remain valid; otherwise, appropriate corrective actions for reanalysis would be taken.

The staff noted that LRA Section A2.1, which provides the UFSAR supplement for the Metal Fatigue of Reactor Coolant Pressure Boundary Program, did not describe this proposed enhancement. Commitment No. 30 in LRA Table A4-1 provided a summary statement for each enhancement. However, for the enhancement to the “corrective actions” program element, the applicant did not provide sufficient details in Commitment No. 30 to describe the corrective actions to be invoked if a component approaches a cycle-counting action limit or a fatigue usage action limit.

By letter dated August 15, 2011, the staff issued RAI B.3.1-1, Request 1, for the applicant to clarify if the four corrective actions, as described above, are applicable when CUF or CUF_{en} has approached the applicant's action limits or the design limit of 1.0. If these corrective actions are applicable to the latter, the staff asked the applicant to describe and justify how the use of these four options for corrective actions will prevent the CUF or CUF_{en} from exceeding the design limit during the period of extended operation. In RAI B.3.1-1, Request 2, the applicant was asked to provide clarification for Commitment No. 30 and to describe the corrective actions to be invoked if a component approaches a cycle-counting action limit, a fatigue usage action limit, and when CUF or CUF_{en} has approached 1.0.

In its response dated September 15, 2011, the applicant stated that corrective actions are initiated when an action limit is reached. Action limits are established to ensure that corrective actions are completed before exceeding the design limit of 1.0. The applicant also stated that LRA Section B3.1, Table A4-1, Commitment No. 30, and the applicant's program basis document will be revised to clarify the corrective actions to be invoked if a component cycle-counting action limit is reached and the corrective actions to be invoked if a CUF or CUF_{en} action limit is reached. In addition, these corrective actions will include repair of the component, replacement of the component, or a more rigorous analysis for the component to demonstrate that the design limit will not be exceeded during the period of extended operation.

The staff noted that the applicant did not provide the applicable revisions to LRA Section B3.1 and Commitment No. 30; therefore, by letter dated October 11, 2011, the staff issued RAI B3.1-1a (followup) requesting that the applicant revise LRA Section A2.1 to describe the corrective actions to be invoked if a component approaches a cycle-counting action limit and a fatigue usage action limit and to provide the revisions of LRA Appendix B3.1 and Table A4-1, Commitment No. 30, consistent with the changes discussed in the response to RAI B3.1-1.

By letter dated November 4, 2011, the applicant supplemented its response to provide the revisions to LRA Section B3.1 that described the corrective actions if a CUF action limit is reached. In its response to RAI B3.1-1a (followup), by letter dated November 21, 2011, the applicant also revised LRA Section A2.1 and Commitment No. 30 to described the corrective actions taken if a CUF action limit is reached (repair or replacement of the component or a more rigorous analysis for the component to demonstrate that the design limit will not be exceeded during the period of extended operation). The staff reviewed these revisions to the LRA and confirmed that they adequately address the corrective actions taken if a CUF action limit is reached and are consistent with the recommendations of the "corrective action" program element of GALL Report AMP X.M1.

Based on its review, the staff finds the applicant's responses to RAI B.3.1-1 and RAI B3.1-1a (followup) acceptable and the concerns resolved because the applicant clarified that corrective actions are taken when an action limit is reached. The applicant will take and complete corrective actions before reaching the design limit of 1.0. The applicant's proposed corrective actions—to repair or replace the component or perform a more rigorous analysis for the component to demonstrate that the design limit will not be exceeded—are consistent with the recommendations in GALL Report AMP X.M1, and the staff confirmed that LRA Sections B.3.1 and A2.1 and Commitment No. 30 were revised accordingly.

The enhancement to the “corrective actions” program element states that the cycle-counting action limits are based on a somewhat arbitrary cycle count that does not accurately indicate approach to the CUF 1.0 fatigue limit. It was not clear to the staff what the “somewhat-arbitrary cycle count” in the applicant’s program references and how it impacts the effectiveness of the program to ensure the design limit on fatigue usage will not be exceeded. In addition, this enhancement states that one acceptable corrective action if a CUF action limit is reached is to enhance fatigue managing to confirm continued conformance to the design limit. It was not clear to the staff how the applicant will “enhance fatigue managing” and whether this action will prevent the CUF from exceeding the design limit during the period of extended operation.

By letter dated August 15, 2011, the staff issued RAI B.3.1-4 requesting that the applicant identify the “somewhat-arbitrary cycle count” and the proposed actions to “enhance fatigue managing.” The applicant was also requested to justify that such proposed actions will be effective to prevent the usage factor from exceeding the design limit during the period of extended operation.

In its response dated September 15, 2011, the applicant stated that the statement of a “somewhat-arbitrary cycle count” is in reference to the fact that the fatigue analyses are based on the number of design transients specified in UFSAR Table 3.9-8. In addition, these are not values that result in a CUF equal to 1.0; therefore, when the design number of a transient is reached, there is inherent margin for measures to be taken to prevent the usage factor from exceeding the design limit of 1.0. The staff noted that the applicant removed this statement and finds it acceptable because it eliminates the confusion as to how the applicant is managing fatigue. In addition, so long as the calculated CUF value is less than 1.0, managing the accumulated cycle counts to be less than the assumed number of cycles in the fatigue evaluation ensures that the design limit of 1.0 is not exceeded.

The applicant also revised this enhancement to state that the corrective action, when a CUF limit is reached, is to do one of the following:

- repair the component
- replace the component (If a limiting component is replaced, assess the effect on locations monitored by the program. If a limiting component is replaced, resetting its cumulative fatigue usage factor to zero, a component which was previously bounded by the replaced component will become the limiting component and may need to be monitored.)
- perform a more rigorous analysis of the component to demonstrate that the design limit will not be exceeded during the period of extended operation

Based on its review, the staff finds the applicant’s response to RAI B.3.1-4 acceptable because the applicant is managing the accumulated number of cycles and CUF to ensure that the design limit of 1.0 is not exceeded, and the applicant’s proposed corrective actions when a CUF limit is reached is consistent with the “corrective actions” program element of GALL Report AMP X.M1. The staff’s concern in RAI B.3.1-4 is resolved.

Based on its review, the staff finds Enhancement 5 acceptable because the applicant’s program, consistent with the recommendations of GALL Report AMP X.M1, ensures that fatigue usage factors will not exceed the design limit of 1.0 during the period of extended operation, and the applicant ensures that the fatigue crack growth and stability analyses remain valid. Otherwise, corrective actions will be taken in accordance with the program.

Enhancement 6. LRA Section B3.1, as amended by letter dated November 21, 2011, states an enhancement to the "monitoring and trending" program element. The applicant stated it will perform a review of design basis fatigue evaluations for ASME Code Class 1 components to confirm whether the NUREG/CR-6260-based locations that have been evaluated for EAF, as documented in LRA Table 4.3-8, are the most limiting components for the STP configuration. If more limiting components are identified, they will be evaluated for effects of the reactor coolant environment on fatigue usage. If the limiting location consists of nickel alloy, the methodology for nickel alloy in NUREG/CR-6909 will be used to perform the EAF calculation. The staff noted that the program description in LRA Section B3.1 indicates that, consistent with GALL Report AMP X.M1, the environmental adjustment factor ($F_{en)}$ factor will be calculated based on NUREG/CR-6583 for carbon and low-alloy steels and based on NUREG/CR-6909 for austenitic stainless steels. The staff noted that the applicant's use of NUREG/CR-6909 for nickel alloys is also consistent with GALL Report AMP X.M1.

The staff noted that the scope of the evaluations is well-defined in Enhancement 6 as the design basis fatigue evaluations for ASME Code Class 1 components. Furthermore, the objective of Enhancement 6 is to manage the most limiting locations of the RCPB for EAF. To achieve this objective, the applicant can (1) re-evaluate the entire RCPB for EAF, or (2) use a method of binning systems and components and then determine the bounding locations from each bin. Any additional locations determined as a result of Enhancement 6 will be managed by the Metal Fatigue of Reactor Coolant Pressure Boundary Program.

Based on its review, the staff finds the applicant's response to previously mentioned RAI B.3.1-5 and RAI B.3.1-5a (followup) and this enhancement acceptable for the following reasons:

- The applicant will evaluate its plant-specific location to determine whether the NUREG/CR-6260 locations are the limiting locations for its plant.
- If more limiting locations are identified, the applicant will evaluate the effects of the reactor coolant environment for the most limiting location.
- The applicant will use the methodology consistent with NUREG/CR-6909 in the evaluation of limiting component consisting of nickel alloy.
- The applicant's enhancement and Commitment No. 34 are consistent with the recommendations in SRP-LR Section 4.3.2.1.3 and GALL Report AMP X.M1 to consider environmental effects for additional plant-specific locations, if applicable.

The staff's concerns in RAI B.3.1-5 and RAI B.3.1-5a (followup) are resolved. The staff also noted that the applicant's evaluation to consider other plant-specific bounding EAF locations is captured in the UFSAR supplement in LRA Section A2.1.

Enhancement 7. LRA Section B3.1, as amended by letter dated November 4, 2011, states an enhancement to the "scope of program" program element. The applicant stated that procedures will be enhanced to ensure the fatigue crack growth analyses, which support the LBB analyses and ASME Code Section XI evaluations, remain valid by counting the transients used in the analyses.

In its response to RAI B3.1-3, the applicant stated that the cycle-counting activity of the Metal Fatigue of Reactor Coolant Pressure Boundary Program is appropriate for management of the LBB analyses because the transients used are consistent with those used in the fatigue design basis. The applicant provided a table that identifies the transients used in LBB analyses and explained that the presented values were used to determine the program limiting values in LRA Table 4.3-2 with the exception of two transients that are not listed in LRA Table 4.3-2. The staff noted that the two exceptions are the “Accumulator Actuation, Accident Operation” and “Reduce Temperature Return to Power” transients. The applicant described the “Accumulator Actuation, Accident Operation” transient as a combination of the “Inadvertent RCS Depressurization” transient, which is monitored, and the “loss-of-coolant accident,” which is a faulted event. The staff finds it acceptable that faulted events are not monitored because the ASME Code does not require faulted events to be considered in fatigue evaluations.

The applicant also stated that the “Reduce Temperature Return to Power” transient was included in pressurizer surge line fatigue crack growth analysis. This transient is designed to improve capabilities of the plant during load follow operations. However, the staff noted that this transient was not incorporated into the applicant’s design basis since the applicant does not practice load follow operations. The staff finds it acceptable that this transient was included as part of the LBB analysis, even though the transient does not occur at the applicant’s site because its inclusion increases the fatigue crack growth and is conservative. In addition, the staff finds it acceptable that the applicant does not monitor this transient because it is not applicable to operation of the plant since the applicant does not operate in a load-following mode.

The applicant stated that the action limits are set at 80 percent of the design value, consistent with the action limits associated with the management of fatigue usage, and that corrective actions include a review the fatigue crack growth analyses that support the LBB exemptions to ensure that the analytical bases remain valid. In addition, reanalysis of a fatigue crack growth analysis must be consistent with, or reconciled to, the originally submitted analysis and receive the same level of regulatory review as the original analysis. By letter dated May 12, 2011, in response to RAI 4.3.2.11-3, the applicant amended the enhancement to the “corrective actions” program element in LRA Section B3.1 to include the corrective actions described above. The staff’s evaluation of this amended enhancement is documented in Enhancement 5.

Based on its review, the staff finds the applicant’s response to RAI B.3.1-3 and RAI B.3.1-3a (followup) and this enhancement acceptable for the following reasons:

- The applicant’s UFSAR and cycle-counting procedures will be updated, consistent with this enhancement, to include the effect of fatigue crack growth.
- The applicant’s program is managing the cycle counts for the transients that were used in these fatigue crack growth analyses, which are the same as those used in the fatigue usage calculations.
- The applicant’s program action limits are set at 80 percent of the design limit to allow for corrective actions to be taken that are specific to these fatigue crack growth analyses.

The staff’s concerns in RAI B.3.1-3 and RAI B.3.1-3a (followup) are resolved.

<u>*Summary*</u>. Based on its audit, and review of the applicant’s responses to RAIs B.3.1-1, B.3.1-1a (followup), B3.1-3, B.3.1-3a (followup), B3.1-4, B3.1-5, and B.3.1-5a (followup), the staff finds that elements one through six of the applicant’s Metal Fatigue of Reactor Coolant Pressure Boundary Program, as enhanced, are consistent with the corresponding program elements of GALL Report AMP X.M1; therefore, they are acceptable.

Operating Experience. LRA Section B3.1 summarizes operating experience related to the Metal Fatigue of Reactor Coolant Pressure Boundary Program. The applicant stated that, in response to Bulletin 88-11, it conducted a plant-specific evaluation of the pressurizer surge lines. From this analysis, the applicant determined that thermal stratification would not affect the integrity of the pressurizer surge lines. Finally, as identified in Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems," dated April 1989, regarding thermal fatigue cracking in normally isolated piping, the applicant stated that it performed a complete analysis of systems connected to the RCS. The review concluded that the potential for the described thermal condition existed only in the normal charging, alternate charging, and auxiliary spray lines. However, these systems are separated, and only hot water can leak through the charging and auxiliary spray lines, which reduces the potential for thermal cycling.

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-specific operating experience information to determine if the applicant had adequately incorporated and evaluated the operating experience related to this program. During its audit, the staff reviewed the applicant's operating experience and condition reports and noted that fatigue issues related to cycle counting had occurred, such as when certain transient cycle counts (loss of charging with prompt restoration without loss of letdown flow and cold over-pressurization mitigation systems actuation) approached their respective action limits. The staff noted that LRA Section B3.1 did not discuss these fatigue-related issues and the actions taken by the applicant.

By letter dated August 15, 2011, the staff issued RAI B.3.1-2 requesting that the applicant justify that objective evidence, with examples and sufficient details from plant-specific experience, has been included in the "operating experience" program element to support the conclusion that the effects of aging will be adequately managed during the period of extended operation.

In its response dated September 15, 2011, the applicant stated that 11 occurrences of loss of charging (also known as charging flow shutoff with prompt return-to-service) are documented in its corrective action database and that the baseline count currently referenced in the LRA accounts for all but one of these occurrences. Furthermore, after a review of the plant instrument data, the applicant concluded that a loss of charging did not occur for this 11th occurrence because the perturbations of charging flow are more characteristic of the charging flow step decrease and return to normal transient that assumes 24,000 occurrences for the design number of cycles. Another example the applicant provided was related to cold over-pressurization mitigation systems activation transient, in which the corrective action database documents three occurrences. The staff noted that this is consistent with the baseline count currently referenced in the LRA and that 10 occurrences were assumed for the design number of cycles. The staff noted that, in both instances, the applicant took corrective actions because the alert limit of 30 percent of the design cycles, which was set to ensure that the transients accumulate at a rate less than that assumed in the design basis, was exceeded.

Based on its review, the staff finds the applicant's response to RAI B.3.1-2 acceptable because it demonstrated that the program was effective in taking corrective actions when pre-set alert limits were reached, and the program ensures that transient events are categorized properly based on the transient definitions. The staff's concern described in RAI B.3.1-2 is resolved.

Based on its audit and review of the application and the applicant's response to RAI B.3.1-2, the staff finds that the applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A2.1 provides the UFSAR supplement for the Fatigue Monitoring Program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program, as described in SRP-LR Table 4.3-2. The staff noted that LRA Section A2.1, as amended by letters dated November 21, 2011, and December 17, 2015, states that this program will also consider the effects of the reactor water environment for a set of locations that includes the NUREG/CR-6260 sample locations for a newer-vintage Westinghouse Plant and plant-specific bounding EAF locations. The staff noted that this is consistent with the recommendations of GALL Report AMP X.M1.

The staff also notes that the applicant committed (Commitment No. 30), as amended by letter dated November 21, 2011, to enhance the Metal Fatigue of Reactor Coolant Pressure Boundary Program prior to entering the period of extended operation. Specifically, the applicant committed to enhance the Metal Fatigue of Reactor Coolant Pressure Boundary Program, which is also captured in the UFSAR supplement, to:

- Include additional locations necessary to ensure accurate calculations of fatigue.
- Include additional transients that contribute significantly to fatigue usage.
- Include counting of the transients used in the fatigue crack growth analyses, which support the LBB analyses and ASME Code Section XI evaluations to ensure the analyses remain valid.
- Include additional transients necessary to ensure accurate calculations of fatigue and fatigue usage monitoring at specified locations and specify the frequency and process of periodic reviews of the results of the monitored cycle count and CUF data at least once per fuel cycle.
- Include additional cycle-count and fatigue usage action limits, which will invoke appropriate corrective actions if a component approaches a cycle-count action limit or a fatigue usage action limit. The acceptance criteria associated with the NUREG/CR-6260 sample locations for a newer vintage Westinghouse plant will account for environmental effects on fatigue, locations in the reactor coolant pressure boundary, and reactor vessel internals locations with fatigue usage calculations.
- Include appropriate corrective actions to be invoked if a component approaches a cycle-count action limit or a fatigue usage action limit (acceptable corrective actions include fatigue reanalysis, repair, or replacement. Reanalysis of a fatigue crack growth analysis must be consistent with or reconciled to the originally submitted analysis and receive the same level of regulatory review as the original analysis.)

The staff also determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirms that its implementation through Commitment Nos. 30

and 34, as amended by letter dated November 21, 2011, prior to the period of extended operation, will make the AMP adequate to manage the applicable aging effects. 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).

3.0.3.2.29 Masonry Wall Program

Summary of Technical Information in the Application. LRA Section B2.1.31 describes the existing Masonry Wall Program as consistent, with an enhancement, with GALL Report AMP XI.S5, “Masonry Wall Program.” The LRA states that the AMP manages cracking of masonry walls and the structural steel restraint systems of the masonry walls. The LRA further states that the program is administered as part of the Structures Monitoring Program and is based on guidance provided in NRC Bulletin 80-11, “Masonry Wall Design,” dated May 1980, and IN 87-67, “Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11,” dated December 1987. The program includes reinforced concrete masonry unit (CMU), removable CMU walls built with restrained masonry or concrete units and stacked without any grouting or reinforcing. The LRA also states that no safety-related piping systems or equipment are attached to the CMU walls. The AMP was amended by the applicant’s letter dated October 10, 2011, to add an enhancement as discussed below.

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 program elements one through six of the applicant’s program to the corresponding program elements of GALL Report AMP XI.S5. As discussed in the audit report, the staff confirmed that each element of the applicant’s program is consistent with the corresponding element of GALL Report AMP XI.S5, with the exception of the “detection of aging effects” program element. For the “detection of aging effects” program element, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The “detection of aging effects” program element in GALL Report AMP XI.S5 recommends masonry walls be inspected every 5 years, with provisions for more frequent inspections in areas where significant loss of material or cracking is observed. However, during its audit, the staff found that the applicant’s Masonry Wall Program inspects an “equivalent unit” at a frequency of no more than 5 years, as opposed to all accessible masonry walls within the scope of the program, which are inspected on a 10-year frequency. Therefore, by letter dated August 15, 2011, the staff issued RAI B2.1.32-2 requesting that the applicant identify the masonry walls that will be inspected on an interval greater than 5 years and to include a justification for the longer interval.

In its response dated October 10, 2011, the applicant stated that “prior to entering the period of extended operation, the program will be enhanced to fully comply with the recommended frequencies from American Concrete Institute (ACI) 349.3R, Table 6.1.” The applicant also committed, through Commitment No. 36, to enhance procedures to increase the frequency of inspection for all structures within the scope of license renewal (i.e., structures built with CMUs) to 5 years, except those that are below grade and in a controlled interior environment. CMU built structures within the primary containment, if any, will also be inspected at 5-year intervals.

The staff reviewed the applicant's response to RAI B2.1.32-2 and finds it acceptable because it aligns the applicant's inspection frequency with the guidance in the industry standard, ACI 349.3R. This document identifies a 5-year inspection interval, similar to the GALL Report recommendation, except for structures in a controlled interior environment, which may be inspected on a 10-year frequency. The staff finds this acceptable because the applicant does not have any operating experience that would indicate a 10-year inspection interval is inadequate for benign interior environments, and all other locations will be inspected on the GALL Report recommended 5-year interval. In addition, the applicant indicated that STP does not have safety-related piping systems or equipment attached to the CMU walls that would otherwise require more frequent inspections. The staff's concern in RAI B2.1.32-2, therefore, is resolved.

Enhancement. LRA Section B2.1.31 was amended by the applicant's letter dated October 10, 2011, which introduces an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that procedures will be enhanced to specify that the inspection frequency for structures within the scope of license renewal will be in accordance with ACI 349.3R, Table 6.1. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S5 and finds it acceptable because, when it is implemented, it will bring the program into alignment with acceptable industry standards, as discussed above under the "Staff Evaluation" section and in response to RAI B2.1.32-2.

Summary. Based on its audit of the applicant's Masonry Wall Program, and review of the applicant's response to RAI B2.1.32-2, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.S5. The staff finds the program acceptable because it will align the applicant's program with the industry standard and render it consistent with that of the GALL Report.

Operating Experience. LRA Section B2.1.31 summarizes operating experience related to the Masonry Wall Program. The LRA states that walkdowns conducted as part of the Structures Monitoring Program have been effective in ensuring that the intended functions of the masonry walls have been maintained. The applicant stated that a review of past inspection results showed instances of minor degradation, such as missing partial blocks and minor cracking, which have resulted in work orders to repair the degradation. The applicant also stated that all areas of degradation identified are documented in condition reports and repaired prior to any loss of intended function.

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 evaluated and incorporated 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 applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which the corresponding GALL Report AMP was evaluated.

UFSAR Supplement. LRA Section A1.31 provides the UFSAR supplement for the Masonry Wall Program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1.

The staff also notes that by letter dated October 10, 2011, the applicant committed (Commitment No. 36) to enhance the Masonry Wall Program prior to entering the period of extended operation. Specifically, the applicant committed to increase the frequency of inspection for all CMU structures to 5 years, except those that are below grade and in a controlled interior environment.

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Masonry Wall Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancement and confirmed that its implementation, through Commitment No. 36, prior to the period of extended operation will make the AMP adequate to manage cracking of masonry walls and the relevant structural steel restraint systems. 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).

3.0.3.3 AMPs That Are Not Consistent with or Not Addressed in the GALL Report

In LRA Appendix B, the applicant identified the following AMPs as plant-specific programs:

- Nickel-Alloy Aging Management Program
- PWR Reactor Internals
- Selective Leaching of Aluminum Bronze
- Protective Coating Monitoring and Maintenance Program
- Managing Loss of Coating Integrity for Internal Coatings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

The fourth listed AMP, "Protective Coating Monitoring and Maintenance Program," corresponding to GALL Report AMP XI.S8, was initially listed as "Not credited" in the original issue of the LRA. Subsequent to this, however, in its letter dated November 30, 2011, the applicant submitted the first annual update to the LRA, and included this new AMP as Section B2.1.39. This is discussed in SER Section 3.0.3.3.4.

For the AMPs that are not consistent with or not addressed by the GALL Report, the staff performed a complete review of the AMPs to determine whether they were adequate to monitor or manage aging. The staff's review of these plant-specific AMPs is documented in this SER section.

3.0.3.3.1 Nickel-Alloy Aging Management Program

Summary of Technical Information in the Application. LRA Section B2.1.34 describes the existing Nickel-Alloy Program as plant-specific. The applicant stated that the Nickel-Alloy Program manages cracking due to PWSCC in RCS locations (RCPB components) that contain Alloy 600. The applicant further defined that for the purposes of the AMP the term “Alloy 600” includes both nickel alloy 600 material and nickel alloy 82/182 weld metal.

Staff Evaluation. In conducting its review of this AMP, the staff notes that Revision 1 of the GALL Report addresses the aging management of nickel alloy components in a unique manner. Rather than recommending an AMP, applicable AMR items (i.e., GALL Report Table 3.1-1, items 31, 34, and their subordinate items) contain specific recommendations for managing the aging of these components. For nickel alloy materials addressed by these AMR items, the recommended aging management activities consist of: (a) use of Inservice Inspection (IWB, IWC, and IWD) AMP, (b) use of Water Chemistry AMP, (c) compliance with all NRC orders, (d) implementing applicable bulletins and GLs, and (e) implementing staff-accepted industry guidelines.

Additionally, in conducting its review, the staff also notes that items (a) and (b) above (inservice inspection and water chemistry) remain valid parts of an overall program to manage aging of nickel alloy components. These programs are, however, independent of this AMP and are reviewed elsewhere in this SER, and are not considered further here. Due to changes in both the GALL Report and the regulations, items (c), (d), and (e), above, are no longer applicable. In Revision 2 of the GALL Report, these recommendations have been replaced by recommendations to use ASME Code Case N-722-1 and MRP-139. Revision 2 of the GALL Report further recommends that the guidance in MRP-139 be replaced by ASME Code Case N-770 when that Code Case is incorporated into 10 CFR 50.55a. Currently, 10 CFR 50.55a(g)(6)(ii)(E)(1) mandates the use of ASME Code Case N-722-1, as modified by paragraphs (g)(6)(ii)(E)(2) through (g)(6)(ii)(E)(4). Additionally, 10 CFR 50.55a(g)(6)(ii)(F)(1) currently mandates the use of ASME Code Case N-770-1, as modified by paragraphs (g)(6)(ii)(F)(2) through (g)(6)(ii)(F)(10).

Based on the acceptability of the applicant’s AMPs to manage water chemistry and inservice inspection (evaluated elsewhere in this SER), its compliance with existing regulations concerning augmented inspections (10 CFR 50.55a(g)(6)(ii)(E)(1) and 10 CFR 50.55a(g)(6)(ii)(F)(1)) and the fact that Revision 2 of the GALL Report does not recommend any further aging management activities, the staff finds elements one through six of the applicant’s AMP acceptable.

Operating Experience. LRA Section B2.1.34 summarizes operating experience related to the Nickel-Alloy Program. In this program element, the applicant described how it has responded to various NRC bulletins and GLs. Additionally, the applicant describes components that have been removed from the Nickel-Alloy Program due to mitigation by component replacement or weld overlay using Alloy 690. Finally, the applicant described an event in which PWSCC was observed in a bottom-mounted instrument (BMI) nozzle. Operating experience such as this often indicates the need for enhancements to an AMP beyond that recommended by the GALL Report. However, in this case, the operating experience reported by the applicant was specifically considered in developing the inspection guidelines contained in Code Case N-722-1. Since the use of this Code Case is recommended by Revision 2 of the GALL Report and required by 10 CFR 50.55a, additional aging management actions on the part of the applicant are not considered necessary in response to this operating experience.

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 functions 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 required by 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 mitigation conducted by the applicant, the staff concluded that the applicant was appropriately addressing the issue of PWSCC.

Based on its review of the application, the staff finds that the applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those as described and recommended by the GALL Report, Revision 2.

<u>UFSAR Supplement</u>. LRA Section A1.34 provides the UFSAR supplement for the Nickel-Alloy AMP.

The staff reviewed this UFSAR supplement description of the program and notes that it—in conjunction with the regulatory requirements associated with this program, which are contained in 10 CFR 50.55a—provides an adequate description of the program.

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); therefore, it is acceptable.

<u>Conclusion</u>. On the basis of its technical review of the applicant's Nickel-Alloy Program, the staff concludes that the applicant demonstrated that, through the use of this AMP, the effects of aging of nickel alloys will be adequately managed so that the intended functions 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).

3.0.3.3.2 PWR Reactor Internals

<u>Summary of Technical Information in the Application</u>. LRA Section B2.1.35 describes the PWR Reactor Internals Program. The applicant defines the PWR Reactor Internals Program as a new, plant-specific AMP that will be used to manage the aging effects that are applicable to the reactor vessel internals (RVIs) components at the facilities. The applicant also stated that this program includes the following commitments:

- The PWR Reactor Internals Program, as described in LRA Section B2.1.35, will be implemented within 24 months after the issuance of EPRI 1016596, "PWR Internals Inspection and Evaluation Guideline MRP-227-A" (Commitment No. 27).
- As additional industry and plant-specific applicable operating experience becomes available, it will be evaluated and incorporated into each new program through the STP condition reporting and operating experience programs (Commitment No. 29).

The applicant states that the PWR Reactor Internals Program manages cracking, loss of material, loss of fracture toughness, dimensional changes, and loss of preload for RVI components that provide a core structural support intended function through implementation of the guidance in EPRI 1016596, "PWR Internals Inspection and Evaluation Guideline (MRP-227, Revision 0)" and EPRI 1016609, "Inspection Standard for PWR Internals (MRP-228, Revision 0)." By letters dated February 27, 2012, and March 28, 2012, the applicant revised the LRA to reflect commitment to the updated guidance in EPRI 1022863 (MRP-227-A, dated January 9, 2012).

The applicant concludes that "[t]he implementation of the PWR Reactor Internals Program provides reasonable assurance that aging effects will be adequately managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the CLB for the period of extended operation."

By letter dated June 30, 2015 (ADAMS Accession No. ML15197A029), the applicant amended the LRA to provide its updated version of the PWR Reactor Internals Program for staff review. The applicant submitted this letter to respond to the requests in RAI B2.1.35-1, Parts 1 and 2, and to bring the program elements for the AMP into alignment with the criteria in ERPI MRP Technical Report (TR) No. 1022863, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A)," dated January 2012[2] and the EPRI MRP background reports used to develop MRP-227-A. The applicant also submitted the reactor vessel internals inspection plan (RVIIP) and updated AMR items for the components, and the applicant's responses to those applicant/licensee action items (A/LAIs) that were issued in the NRC SE for MRP-227-A, dated December 16, 2011 (ADAMS Accession No. ML11308A770). Details of the updated PWR Reactor Internals Program, RVIIP, and ALAI responses are provided in the letter of June 30, 2015.

Staff Evaluation. The staff reviewed program elements 1 through 10 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. RVIIP criteria that differ from the inspection and evaluation (I&E) guidelines in MRP-227-A are either evaluated in the respective program element that is impacted by those criteria or in the staff's evaluation of A/LAI No. 2, which follows later in this evaluation.

By letter dated July 16, 2014 (ADAMS Accession No. ML14183B719), the staff issued RAI B.2.1.35-1, Parts 1 and 2, to the applicant to address criteria in NRC Regulatory Issue Summary (RIS) No. 2011-07, "License Renewal Submittal Information for Pressurized Water Reactor Internals Aging Management" (ADAMS Accession No. ML111990086), and to ensure that the applicant's AMP would be consistent with the latest augmented inspection criteria for Westinghouse-design RVI components in the MRP-227-A report. In Part 1 of this RAI, the staff asked the applicant to provide either an LRA amendment or update that includes an updated AMP, updated AMR items, and any applicable inspection plan(s) for the RVI components at STP, Units 1 and 2, that are based on the guidance in LR-ISG-201104, including responses to those A/LAIs that were identified in the staff's SE for MRP-227, dated December 16, 2011. In

[2] This report was collectively submitted in ADAMS Accession Nos. ML12017A191, ML12017A192, ML12017A193, ML12017A194, ML12017A195, ML12017A196, ML12017A197, and ML12017A199, and are referred to as MRP-227-A.

RAI B.2.1.35-1, Part 2, staff also asked the applicant to address how cracking of the clevis insert bolts would be managed during the period of extended operation.

The applicant responded to RAI B.2.1.35-1, Parts 1 and 2, in a letter dated June 30, 2015 (ADAMS Accession No. ML15197A029), and provided all of the requested information. The information in the letter of June 30, 2015, includes the applicant's updated version of the PWR Reactor Internals Program, the RVIIP for the RVI components, the applicant's evaluation of the impact that generic operating experience with clevis insert bolt cracking would have on the protocols for implementing the applicant's AMP and RVIIP, and the applicant's responses to those A/LAIs that were issued in the NRC SE for MRP-227-A dated December 16, 2011. The submittal of the information in the letter of June 30, 2015, conforms to the information requested in the RAI B.2.1.35-1, Parts 1 and 2; therefore, RAI B.2.1.35-1, Parts 1 and 2 are resolved.

The staff's evaluation of each of the program elements for the PWR Reactor Internals Program are given in the subsections that follow. Aspects of the RVIIP that may impact the program element criteria are evaluated in the applicable subsection for the program element. The staff's evaluation of the applicant's bases for responding to applicable A/LAIs follows after the staff's evaluation of the "operating experience" program element.

Scope of Program. The applicant's current "scope of program" program element for the PWR Reactor Internals Program is documented in the letter of June 30, 2015. The applicant stated that the scope of the AMP is based on the augmented I&E criteria in MRP-227-A and includes those components that provide a core support structure intended function and that are identified as Westinghouse-defined "Primary" and "Expansion" components, as designated in Tables 4-3 and 4-6 of MRP-227-A, respectively. The applicant also stated that the program includes those components that are managed by other "Expansion Programs," as identified in Table 4.9 of MRP-227-A. Specific components that are within the scope of these inspection categories are given in the "scope of program" program element for the PWR Reactor Internals Program, as provided in the letter of June 30, 2015.

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.1, which states that the specific program necessary for license renewal should be identified and should include the specific SCs that the program manages. The staff also compared the applicant's "scope of program" program element to the analogous element in GALL Report AMP XI.M16A, "PWR Vessel Internals."

The staff noted that, with the exception of those components that the applicant identified as constituting deviations from the generic Westinghouse design assessed in the MRP-227-A or MRP-191 reports, the "scope of program" program element for the AMP was consistent with that provided in GALL Report AMP XI.M16A and MRP-227-A, and appropriately identified those RVI components that were included as "Primary" category, "Expansion" category, or ASME Section XI "Expansion Program" components for the AMP. The staff noted that the "scope of program" was consistent with the criteria in SRP-LR Section A.1.2.3.1 for condition monitoring programs. Therefore, with the exception of these stated deviations for components in the plant design and those components for which the staff needed additional information, the staff finds the components in the "scope of program" program element to be acceptable because they are consistent with these identified in MRP-227-A, as referenced in GALL Report AMP XI.M16A and with the criteria in SRP-LR Section A.1.2.3.1.

The staff noted that the MRP-227-A report includes "No Additional Measures" components, which are RVI components that are within the scope of the MRP-227-A report but are not within the scope of any “Primary,” “Expansion,” or “Expansion Program” category protocols in the report. The staff also noted that the PWR Reactor Internals Program did not include “No Additional Measures” components in the scope of the AMP. The staff also noted that some “No Additional Measures” components could be within the scope of ASME Section XI Examination Category B-N-2 or B-N-3 requirements in the CLB even though they are not categorized as “Primary,” “Expansion,” or “Expansion Program” components in MRP-227-A.

By letter dated November 30, 2015, the staff issued RAI 3.0.3.3.6-1 to address these issues. Specifically, the staff asked the applicant to justify the basis for omitting “No Additional Measures” components from the scope and population of components in the PWR Reactor Internals Program. The staff further asked the applicant to identify all components in the PWR Reactor Internals Program that are defined as “No Additional Measures” components in the AMP and RVIIP but constitute ASME Section XI Examination Category B-N-3 removable core support structure components or non-welded Examination B-N-2 interior attachments in the CLB. For components that fall into this category, the staff asked the applicant to identify the AMP that will be used to implement the applicable inservice inspection (ISI) requirements for the components during the period of extended operation.

By letter dated December 17, 2015 (ADAMS Accession No. ML16005A093), the applicant responded to RAI 3.0.3.3.6-1. The applicant stated that it identified a fourth group of components that consists of PWR internal components that have been classified as “No Additional Measures.” In its response, the applicant provided its update to the PWR Reactor Internals Program and License Renewal Basis Document to represent that “No Additional Measures” components are included in the scope of the AMP. The applicant also clarified that none of the “No Additional Measures” components are core support structures and, therefore, are not within the scope of ASME Section XI Examination Category B-N-2 or B-N-3 requirements. The staff reviewed the amended LRA Section B2.1.35, PWR Reactor Internals Program, and noted that the updated sections reflect the RAI response. The staff further noted that the LRA includes all of the component categories that are addressed in MRP-227-A. The staff finds the applicant’s response acceptable because: (a) the scope of the applicant’s PWR Reactor Internals Program is consistent with the scope of component categories of MRP-227-A and (b) the applicant clarified that it does not have any “No Additional Measures” components that are within the scope of ASME Section XI Examination Category B-N-2 or B-N-3 requirements. The staff’s concerns in RAI 3.0.3.3.6-1 are resolved.

In the MRP-227-A report, the EPRI MRP identifies that the extra-long (XL) lower core plates in Westinghouse units with XL core designs are ASME Section XI “Expansion Program” components for the AMP. The staff noted that the designation of the inspection category for the XL lower core plates in the RVIIP was consistent with the categorization of these components in the MRP-227-A report. However, the staff also noted that, in the “scope of program” program element for the AMP, the applicant identified that XL lower core plates at STP are “Expansion” category components for the AMP.

By letter dated November 30, 2015, the staff issued RAI 3.0.3.3.6-2 requesting that the applicant address apparent inconsistencies between the inspection categories for the XL lower core plates at Unit 1 and 2. Specifically, the staff asked the applicant to clarify whether the XL lower core plates (one plate in each unit) are “Expansion” components or “Existing Program” components for the PWR Reactor Internals Program, or both. If the plates are “Expansion” components, the applicant was asked to identify and justify the basis for selecting the “Primary” components that are linked to the XL lower core plates as “Expansion” components for the AMP and the RVIIP.

By letter dated December 17, 2015, the applicant responded to RAI 3.0.3.3.6-2. The applicant stated that the XL lower core plates are “Existing Program” components. The applicant amended its LRA to change the classification from “Expansion” component to “Existing Program.” The staff reviewed the amended LRA and noted that XL lower core plate classification is consistent with MRP-227-A; therefore, the staff finds the applicant’s response acceptable. The staff’s concerns in RAI 3.0.3.3.6-2 are resolved.

In the letter of June 30, 2015, the applicant identified a number of component-specific deviations from the generic Westinghouse RVI design that were evaluated in MRP-191 and MRP-227-A reports for lower internal assembly and lower core support assembly components. The staff evaluates the impact of these deviations on the program element criteria for this AMP and the inspection criteria for the RVIIP in the evaluation of the applicant’s response to A/LAI No. 2, which follows later in this evaluation.

The staff finds the applicant’s “scope of program” program element acceptable because the staff confirmed that the program includes the components of its RVIs design consistent with the design assumptions of MRP-227-A and, therefore, demonstrates conformance with the “scope of program” program element of SRP-LR Section A.1.2.3.1.

Preventive Actions. The applicant’s current “preventive actions” program element for the PWR Reactor Internals Program is documented in the letter of June 30, 2015. The applicant stated that the PWR Reactor Internals Program does not prevent aging degradation effects but monitors the RVI components to detect degradation prior to loss of function. Preventive measures to mitigate aging effects, such as loss of material and cracking, include monitoring and maintaining the reactor coolant chemistry. The staff noted that the applicant controls the reactor coolant chemistry by following the guidelines of EPRI 101986, “PWR Primary Water Chemistry Guidelines,” Volume 1, through its Water Chemistry Program.

The staff reviewed the applicant’s program element criteria in accordance with 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 that these actions should mitigate or prevent aging degradation. The SRP-LR also states that some condition or performance monitoring programs do not rely on preventive actions; therefore, this information need not be provided.

The staff noted that the augmented methodology in MRP-227-A does not rely on preventive or mitigative activities and instead defers implementation of such activities to the application of an applicant’s Water Chemistry Program. Therefore, the staff finds the applicant’s “preventive actions” element to be acceptable because the staff confirmed that: (a) the PWR Reactor Internals Program is a sampling-based condition monitoring program that does not rely on preventive actions, and (b) instead, such preventive actions will be implemented in accordance with the applicant’s Water Chemistry Program for the LRA, which the staff determined is consistent with the recommendations in GALL Report AMP XI.M2, Water Chemistry. The staff’s evaluation of the Water Chemistry Program is provided in SER Section 3.0.3.2.1.

Parameters Monitored or Inspected. The applicant’s current “parameters monitored or inspected” program element for the PWR Reactor Internals Program is documented in the letter of June 30, 2015. The applicant stated that the PWR Reactor Internals Program uses visual inspection or volumetric (ultrasonic testing or UT) to monitor for the occurrence of the aging effects of cracking, loss of material, loss of fracture toughness, changes in dimension, and loss of preload. The applicant stated that the inspections are performed in accordance with the guidance of MRP-227-A or, for "Existing Program" components, with the ISI requirements specified in the ASME Code Section XI for Examination Category B-N-3 components.

The staff reviewed the applicant's program element criteria in accordance with the criteria in SRP-LR Section A.1.2.3.3, which states that, for condition monitoring programs, the parameter monitored or inspected should be capable of detecting the presence and extent of aging effects.

The staff noted that the visual examination and volumetric examination (i.e., UT) used to reveal the presence of parameters indicative of the applicable aging effects were reviewed as part of the NRC's review and endorsement of the MRP-227-A report and were approved in the NRC's SE for MRP-227-A, dated December 16, 2011. Therefore, the staff finds the applicant's "parameters monitored or inspected" program element to be acceptable because the staff confirmed that: (a) the criteria are consistent with the guidelines in MRP-227-A or the ISI requirements in the ASME Code Section XI for Examination Category B-N-3 components, and (b) this demonstrates conformance with the criteria of condition monitoring programs in SRP-LR Section A.1.2.3.3.

Detection of Aging Effects. The applicant's current "detection of aging effects" program element for the PWR Reactor Internals Program is documented in the letter of June 30, 2015. The applicant stated that the PWR Reactor Internals Program detects aging effects through the implementation of the parameters monitored or inspected criteria and bases for primary components, expansion components, and existing program components in MRP-227-A, Tables 4-3, 4-6, and 4-9, respectively. The applicant also stated that 100 percent of the accessible volume/area of each component in the "Primary" and "Expansion" categories will be examined. The minimum examination coverage for primary and expansion inspection categories is 75 percent of the component's total (accessible plus inaccessible) population. When addressing a set of like components (e.g., bolting), the minimum examination coverage for "Primary" and "Expansion" categories is 75 percent of the component's total (accessible plus inaccessible) population.

The staff performed its review in accordance with the criteria for "monitoring and trending" elements in SRP-LR Section A.1.2.3.4, which states that the method or technique (such as visual, volumetric, or surface inspection techniques), frequency, and timing of inspections may be linked to plant-specific or industry-wide operating experience. For condition monitoring programs that are based on sampling-based inspection processes, the SRP-LR also states that the applicants should provide the basis for the inspection population and sample size, including sample expansion.

The staff noted that, for the PWR Reactor Internals Program, the details of the components for inspection, inspection techniques, program population of components, and inspection coverage and sample size (including components expansion) were reviewed and approved as part of the staff's review of the MRP-227-A report, as documented in the NRC's SE of December 16, 2011. The staff also noted that the applicant's "detection of aging effects" element for the AMP and RVIIP refers to these criteria, as referenced in the approved MRP-227-A report, and therefore demonstrates conformance with the "detection of aging effects" criteria in SRP-LR Section A.1.2.3.4. Therefore, the staff finds the criteria in the "detection of aging effects" program element to be acceptable because: (a) they are consistent with those approved in the NRC's SE for MRP-227-A report, and (b) they have been demonstrated to be consistent with the criteria for sampling-based condition monitoring programs in SRP-LR Section A.1.2.3.4.

Monitoring and Trending. The applicant's current "monitoring and trending" program element for the PWR Reactor Internals Program is documented in the letter of June 30, 2015. The applicant stated that the PWR Reactor Internals Program provides examination acceptance criteria (element 6) for conditions detected as a result of monitoring the primary components (element 4), as well as criteria for expanding the inspections to the expansion components when warranted by the level of degradation detected in the primary components. Based on the identified aging effect and supplemental examinations, if required, the disposition process results in an evaluation and determination of whether to accept the condition until the next examination or to implement corrective actions. The applicant stated that detected conditions that do not satisfy the examination acceptance criteria (element 6) are required to be dispositioned through a CAP (element 7), which may require repair, replacement, or analytical evaluation for continued service until the next inspection. The applicant states (in the "detection of aging effects" program element) that the evaluation of defects will be performed in accordance with engineering evaluation methods in WCAP-17096-NP.

The staff performed its review in accordance with the criteria for "monitoring and trending" program elements in SRP-LR Section A.1.2.3.4, which states that the monitoring and trending activities should be described and should provide a prediction of the extent of degradation and thus effect timely corrective or mitigative actions. The SRP-LR also indicates that plant-specific and/or industry-wide operating experience may be considered in evaluating the appropriateness of the technique and frequency.

The staff noted that the applicant's "monitoring and trending" criteria in the AMP and for the RVIIP were in accordance with those criteria specified in Tables 4-3, 4-6, and 4-9 of the MRP-227-A report, with the exception of those deviations that relate to the lack of a lower core support structure assembly in the plant designs. The staff evaluates these deviations later in this SER section. The staff also confirmed that the NRC approved the use of WCAP-17096-NP for the evaluation of defects in an SE dated September 10, 2015 (ADAMS Accession No. ML15222A936). Therefore, with the exception of these deviations, the staff finds the criteria in the "monitoring and trending" program element are acceptable because: (a) they are consistent with those approved in the NRC's SEs for the MRP-227-A and WCAP-17096-NP reports, and (b) they are consistent with the monitoring and trending criteria for condition monitoring programs in SRP-LR Section A.1.2.3.5.

Acceptance Criteria. The applicant's current "parameters monitored or inspected" program element for the PWR Reactor Internals Program is documented in the letter of June 30, 2015. The staff reviewed the applicant's program element information against the criteria in SRP-LR Section A.1.2.3.6, which states that the quantitative or qualitative acceptance criteria of the program and its basis should be described against the need for which corrective actions are evaluated. The SRP-LR states that the acceptance criteria may be quantitative or qualitative, but it clarifies that it is not necessary to justify further acceptance criteria established in either the final safety analysis report (FSAR), plant TS, or other codes and standards incorporated by reference into NRC regulations because they are a part of the CLB. Nor is it necessary to justify the acceptance criteria that have been established in either NRC-accepted or NRC-endorsed methodologies, such as those that may be given in NRC-approved or NRC-endorsed topical reports or NRC-endorsed codes and standards, because the acceptance criteria referenced in these types of documents have been subject to an NRC review process and have been approved or endorsed for their applications.

The staff noted that the applicant provided acceptance criteria for "Primary" and "Expansion" component examinations that are consistent with those specified in Section 5 of MRP-227-A, and for “Expansion Program” components, in Article IWB-3500 of the ASME Code Section XI. The staff also noted that the applicant’s acceptance criteria, as stated in the MRP-227-A report for “Primary” and “Expansion” components or in the ASME Code Section XI for “Expansion Program” components, conform to criteria in SRP-LR Section A.1.2.3.6 because they are defined in accordance with NRC-required or NRC-endorsed programs that have been confirmed to meet the objectives stated in SRP-LR Section A.1.2.3.6. Therefore, the staff finds that the applicant’s “acceptance criteria” program element acceptable because: (a) the “acceptance criteria” program element is consistent with those approved in the NRC’s SEs for the MRP-227-A report, and (b) the “acceptance criteria” program element is consistent with the acceptance criteria for condition monitoring programs in SRP-LR Section A.1.2.3.6.

Corrective Actions. The applicant’s current “corrective actions” program element for the PWR Reactor Internals Program is documented in the letter of June 30, 2015. The applicant stated that the following corrective actions are available for the disposition of detected conditions that exceed the examination acceptance criteria:

(1) supplemental examinations to further characterize and potentially dispose of a detected condition (Section 5.0 of MRP-227-A)

(2) engineering evaluation that demonstrates the acceptability of a detected condition (Section 6.0 of MRP-227)-A

(3) repair in order to restore a component with a detected condition to acceptable status (ASME Code Section XI)

(4) replacement of a component with an unacceptable detected condition (ASME Code Section XI)

(5) other alternative corrective action bases if previously approved or endorsed by the NRC

The applicant also stated that relevant indications failing to meet applicable acceptance criteria are repaired or replaced in accordance with plant procedures or appropriate codes and standards.

The staff reviewed the applicant’s program element information against the criteria in SRP-LR Section A.1.2.3.7. The SRP-LR states that corrective actions should be taken when the acceptance criteria are not met and should be described in appropriate detail or reference source documents. The SRP-LR states that if corrective actions permit analysis without repair or replacement, the analysis should ensure that the structure- and component-intended function(s) are maintained consistent with the CLB.

The staff noted that the corrective actions described by the applicant conform to those stated in Section 6 of MRP-227-A, with the exception that alternatives to those corrective actions could be proposed if approved or endorsed for acceptance by the NRC.

The staff also noted the applicant’s corrective action bases conform to the recommended criteria in SRP-LR Section A.1.2.3.7 because the applicant will be using either: (a) the corrective actions in the approved MRP-227-A methodology, (b) NRC-endorsed corrective actions in the applicable ASME Code Section XI rules, or (c) alternative corrective action bases if endorsed or approved by the staff.

Therefore, the staff finds the applicant’s “acceptance criteria” program elements acceptable because: (a) “acceptance criteria” are consistent with those approved in the MRP-227-A report or NRC-endorsed codes or standards, and (b) “acceptance criteria” are demonstrated to be consistent with the acceptance criteria for condition monitoring programs in SRP-LR Section A.1.2.3.7.

Confirmation Process and Administrative Controls. The applicant’s current “confirmation process” and “administrative controls” program element for the PWR Reactor Internals Program are documented in the letter of June 30, 2015. The applicant stated that the QA requirements for repair and replacement activities are also included in its Operations QA Plan.

The staff reviewed the applicant’s program element information against the criteria in SRP-LR Sections A.1.2.3.8 and A.1.2.3.9, which state that the confirmation process and administrative controls of the AMP should be described. The SRP-LR states that the confirmation process should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective, and that the administrative controls should provide a formal review and approval process.

The staff noted that the applicant implements the confirmation process and administrative controls aspects of the PWR Reactor Internals Program in accordance with the criteria in Section 7 of the MRP-227-A reports and the applicant’s 10 CFR Part 50, Appendix B, program. The staff also noted that this demonstrates that the applicant will take appropriate corrective actions if age-related degradation exceeding the acceptance standards in the RVI components. The staff also noted that this demonstrates conformance with the criteria for “confirmation process” and “administrative controls” program elements in SRP-LR Sections A.1.2.3.8 and A.1.2.3.9. Therefore, the staff finds the applicant’s “confirmation process” and “administrative controls” program elements acceptable because: (a) they are consistent with those approved in the MRP-227-A report, and (b) they are consistent with the acceptance criteria in SRP-LR Sections A.1.2.3.8 and A.1.2.3.9.

Review of License Renewal Applicant Action Items. In the staff’s SE (ADAMS Accession No. ML11308A770) of TR No. MRP-227-A, the staff issued the following A/LAIs on the report that apply to Westinghouse-designed RVI components:

A/LAI No. 1. In this action item, the staff requested demonstration that the assumptions and criteria for evaluating PWR reactor internal components in the MRP-227-A report are bounding for the design of the components at the applicant’s nuclear plant. In the applicant’s letter of June 30, 2015, the applicant stated that its RVI components are reasonably represented by the design and operating history assumptions regarding neutron fluence, temperature, materials, and stress values in the MRP-191 FMECA and in the MRP-232 functionality analysis.

The staff noted that the assessments performed by the industry addressed the broad set of assumptions about plant operation for the U.S. domestic fleet of PWRs. Because a number of industry licensees were developing their efforts to address the actions the staff requested in A/LAI No. 1, the staff held a series of meetings, some non-public due to proprietary information discussed and others public, with members of Westinghouse Electric Company, LLC, the EPRI MRP, and NRC-licensed utilities to: (a) address the staff’s action plan, (b) encourage the development of a generic approach that could be used to resolve the requests in A/LAI No. 1, and (c) establish a path for receiving comprehensive and consistent utility responses that would address the applicability of the MRP-227-A methodology for PWRs with either Westinghouse or CE RVI designs. As a result of these discussions, a PWR license renewal applicant may conclude that the design of its RVI components are bounded by the assumptions in MRP-227-A if it can demonstrate that the reactor design is consistent with the following design assumptions:

- The plant has 30 years of operation with high leakage core loading patterns (fresh fuel assemblies loaded in peripheral locations) followed by implementation of a low-leakage fuel management strategy for the remaining 30 years of operation.

- The plant operates using base load operations, (i.e., typically operates at fixed power levels and does not usually vary power on a calendar or load demand schedule).

- The plant has not implemented any design changes beyond those identified in general industry guidance or recommended by the original vendors.

Additional criteria for resolving the request in A/LAI No. 1 are given in EPRI MPR non-proprietary Class 3 Letter 2013-025, "MRP-227-A Applicability Template Guideline," which was issued by the EPRI MRP on October 14, 2013 (ADAMS Accession No. ML13322A454). In this letter, ERPI provided additional criteria for resolving the request in A/LAI No. 1, as related to the plant-specific RVI stress level and neutron fluence assessments for Westinghouse-designed PWR RVI components:

(1) Question 1 Cold-worked Materials: Does the plant have non-weld or bolting austenitic stainless steel (SS) components with 20 percent cold work or greater, and if so, do the affected components have operating stresses greater than 30 ksi? (If both conditions are true, additional components may need to be screened in for stress corrosion cracking, SCC)?

(2) Question 2 Fuel Design or Fuel Management: Does the plant have atypical fuel design or fuel management that could render the assumptions of MRP-227-A, regarding core loading/core design, non-representative for that plant?"

The NRC staff reviewed EPRI MPR non-proprietary Class 3 Letter 2013-025 and documented its conclusion in the SE, "Evaluation of WCAP-17780-P, 'Reactor Internals Aging Management MRP-227-A Applicability for Combustion Engineering and Westinghouse Pressurized Water Reactor Designs,' and MRP-227-A, Applicability Guidelines for CE and Westinghouse Pressurized Water Reactor Designs," dated November 7, 2014 (ADAMS Accession No. ML14309A484). The staff concluded that if an applicant or licensee demonstrates that its plant(s) comply with the guidance in MRP Letter 2013-025, there is reasonable assurance that the I&E guidance of MRP-227-A will be applicable to the specific plant(s). The guidance in MRP Letter 2013-025 provides an acceptable basis for licensees to prepare responses to the generic RAI questions.

During the week of March 21–25, 2016, the staff performed a supplemental audit of the LRA for STP Units 1 and 2. As part of this audit, the staff audited the applicant's basis for demonstrating conformance with the design assumptions stated in Section 2.4 of the MRP-227-A report and for resolving the "cold-worked materials" question in EPRI Letter No. 2013-025.

As stated in the staff Audit Report, dated August 30, 2016 (ADAMS Accession No. ML16218A256), the staff found that the "scope of program" element for the AMP provides an acceptable basis for demonstrating that the MRP-227-A report is bounding for the RVI design at STP Units 1 and 2. Specifically, the staff noted that the applicant's "scope of program" element basis identifies that:

(1) The STP reactor units have operated for less than 30 years with high leakage fuel loading patterns.

(2) The STP reactor units operate at fixed load and do not normally vary power based on calendar or load demand schedules.

(3) The applicant has not implemented design changes at STP Units 1 or 2 not recommended by applicable industry vendors or organizations.

The staff confirmed that the “scope of program” element provides sufficient demonstration that: (a) the reactor units have operated for more than 30 years of operations using a low leakage fuel management strategy, (b) the reactors operate using base-load operations, and (c) the applicant has not implemented any design modifications outside of those recommended by Westinghouse Electric Company, the EPRI MRP, or other applicable industry organizations. Therefore, the staff concludes that the applicant provided sufficient demonstration that the designs of the RVI components at Units 1 and 2 are consistent with the design criteria and assumptions stated in Section 2.4 of the MRP-227-A report.

As to Question 1 associated with cold-worked components, the staff found that the supporting plant documents for this AMP provide an acceptable basis for demonstrating that the design stresses for the RVI components at STP Units 1 and 2 are within the bounding design stress assumptions for these components in the MRP-227-A and MRP-191 reports. Specifically, the staff confirmed that the applicant’s documents provide sufficient demonstration that the RVI components either were not sufficiently cold-worked during component or plant fabrication practices, or that the additional residual stress loads of the components were appropriately accounted for in the EPRI MRP design assumptions for the components in the MRP-191 report. Specifically, based on the review of the applicable plant records, the staff noted that the design documents provide sufficient demonstration that the applicant had restricted the procured yield strengths of the component materials to acceptable levels, such that any amounts of strain hardening imparted to the components during the fabrication process would be minimized. Based on this review, the staff finds that the applicant provided sufficient demonstration that the levels of cold work and stress loads for the RVI components are within the design assumptions for these parameters in either the MRP-227-A or MRP-191 reports. Therefore, the staff finds the applicant’s response to Question 1 as related to screening of RVI components for cold work acceptable.

- With respect to Question 2, the EPRI MRP developed the criteria in EPRI MRP Letter No. 2013-025 to assist applicants of Westinghouse-designed PWRs in addressing the A/LAI request. In this letter, the EPRI MRP recommended that applicants owning Westinghouse-designed PWRs should provide their assessments of the following parameters: demonstrate that the distance between the top of the active fuel and the upper core plate is greater than 12.2 inches
- demonstrate that the average core power density is less than 124 watts/cm^3
- demonstrate that the heat generation figure of merit, F, is less than or equal to 68 watts/cm^3

In its SE related to the EPRI MRP (ADAMS Accession No. ML14309A484), the staff agreed that demonstration of conformance with the acceptance criteria for these plant parameters would serve as a valid basis for concluding that the assumptions used in MRP-227-A are bounding for the design of the RVI at their facilities. However, the staff noted that STPNOC’s letter of June 30, 2015, did not include an assessment of the parameters listed above, as recommended in MRP Letter No. 2013-025. By letter dated November 30, 2015, the staff issued RAI 3.0.3.3.6-3, which asked the applicant to explain why the June 30, 2015, letter for resolving A/LAI No. 1, did not include an assessment of the three parameters listed above, as recommended in EPRI MRP Letter 2013-025. The staff also asked the applicant to justify why such an assessment would not be needed as part of the basis for concluding that the assumptions used to develop MRP-227-A are bounding for the design of the RVI components at Units 1 and 2.

By letter dated December 17, 2015, the applicant responded to RAI 3.0.3.3.6-3. The applicant stated that Westinghouse evaluated the reactor internals components at STP with regard to fuel design and fuel management in accordance with the industry guidelines provided in MRP 2013-025. The applicant stated that for STP Unit 1, based on the average of the first 19 fuel cycles of operation, the nominal distance between the top of the active fuel and the bottom of the upper core plate was not less than 12.2 inches. Also, the applicant stated that STP Unit 1 has operated at a rated power level of 3,853 MWt for the last eight operating fuel cycles, which corresponds to a core power density of 101.2 W/cm^3. The applicant also stated that, based on the last eight operating fuel cycles, the heat generation figure of merit was kept under 68 W/cm^3.

For STP Unit 2, the applicant stated that, based on the average of the first 17 fuel cycles of operation, the nominal distance between the top of the active fuel and the bottom of the upper core plate was not less than 12.2 inches. Also, the applicant stated that STP Unit 2 has operated at a rated power level of 3,853 MWt for the last eight operating fuel cycles, which corresponds to a core power density of 101.2 W/cm^3. The applicant also stated that, based on the last eight operating fuel cycles, the heat generation figure of merit was kept under 68 W/cm^3.

Based on its review of the application and RAI responses, the staff finds that the applicant provided adequate demonstration that the fuel loading patterns assumed in MRP-227-A will be representative of plant operations at STP Units 1 and 2 because the applicant demonstrated that the three fuel load parameters are within the thresholds set for these parameters in EPRI MRP Letter No. MRP-2013-25. Therefore, the staff finds the applicant’s response to Question 2 acceptable because the applicant demonstrated that the core loading patterns for the reactor unit are bounded by the fuel loading assumptions for Westinghouse-designed internals in the MRP-227-A report. A/LAI No. 1 and concerns in RAI 3.0.3.3.6-3 are resolved.

A/LAI No. 2. In this action item, the staff requested that PWR applicants perform a review of the CLBs against the information in the MRP-191 report and identify any missing component(s) from those evaluated in the MRP report. The staff also requested that the applicant identify and propose any necessary modifications of the program defined in MRP-227-A, when applied to the design of the RVI components at its facility.

In its response to A/LAI No. 2, the applicant stated that the generic scoping and screening of the RVI, as summarized in the MRP-191 and MRP-232 reports (in order to support the inspection criteria in MRP-227-A), are applicable to STP Units 1 and 2 with no modifications for the components. The applicant also stated that the RVI components are consistent with the augmented inspection criteria in MRP-227-A for all components and that the protocols in MRP-227-A do not need to be modified under the criteria in A/LAI No. 2.

The staff noted, however, UFSAR Section 4.1 identifies that some of the RVI components were modified at the plants. Thus, the staff determined that it needed confirmation that any RVI design modifications at STP Unit 1 or Unit 2 would not result in a deviation from the generic

Westinghouse design evaluated in the MRP-191 and MRP-227-A reports. By letter dated November 30, 2015, the staff issued RAI 3.0.3.3.6-4 to the applicant. In this RAI, the staff asked the applicant to identify all RVI design assembly component configurations (other than those for the deviations on lower core support structure assembly components) that have not been evaluated by or differ from those generically evaluated in the MRP-191, MRP-232, and MRP-227-A reports, other than those for lower core support assembly components (which are the topic of RAI 3.0.3.3.6-5). For components that have corresponding components in the generic MRP evaluations but differ from the configurations in the generic evaluation, the staff asked the applicant to clarify how the stress levels and neutron fluences for these components compare to those assessed for corresponding components in the generic MRP design evaluations. Based on this comparison, the staff asked the applicant to justify why augmented inspection protocols for the components would not need to be proposed for the components on a plant-specific basis for the AMP. For components that were not analyzed in the MRP reports, the staff asked the applicant to justify why plant-specific aging management criteria would not need to be proposed for the components on a plant-specific basis for the AMP.

By letter dated December 17, 2015, the applicant responded to RAI 3.0.3.3.6-4. The applicant stated that it reviewed its reactor internals plant design and concluded that all of its RVI design assembly component configurations are accounted for in MRP-191. The applicant stated that this provides the basis for meeting the requirements for application of MRP-227-A to manage age-related material degradation for reactor internal components. In its response, the applicant provided PWROG-15001-NP, "South Texas Project Unit 1 and Unit 2 Summary Report for Applicant/Licensee Action Items 1, 2, and 7." The staff reviewed the report and noted that the applicant identified several components that were made from different materials than those specified in MRP-191. However, the applicant evaluated the material differences and concluded that there were no effects on the aging management strategy or the aging effect is already being managed by an alternate program. The staff noted that the applicant's conclusions justify that the applicant's RVI design is bounded by the MRP-191, MRP-232, and MRP-227-A reports. The staff finds the applicant's response acceptable because the applicant identified the plant-specific design differences from the MRP reports and provided sufficient demonstration that the EPRI MRP's protocols for inspecting the components do not need to be altered or augmented beyond those recommended for the components in MRP-227-A. The staff's concerns in RAI 3.0.3.3.6-4 are resolved.

In MRP-27-A, the EPRI MRP identifies that the column bodies and column bolts in lower core support assemblies of Westinghouse-design PWRs are "Expansion" components for Westinghouse-design RVI management programs. The staff noted that, although the applicant identified that the design of the RVI assemblies at STP do not include these types of components, the applicant did not identify these departures as deviations from the generic design evaluated in MRP-191 and MRP-227-A reports. The staff also noted that these departures would change a number of generic "Primary" to "Expansion" category relationships for the RVIIP from those defined in the MRP-227-A report for these Westinghouse-design internals.

By letter dated November 30, 2015, the staff issued RAI 3.0.3.3.6-5 to the applicant. In this RAI, the staff asked the applicant to justify why the response to A/LAI No. 2 had not identified the lack of a lower core support structure assembly and lower core support column bodies and bolts (MRP-227-A "Expansion" components) as a deviation from the generic Westinghouse design that was evaluated in the MRP-191 and MRP-227-A reports.

By letter dated December 17, 2015, the applicant responded to RAI 3.0.3.3.6-5. The applicant stated that the lower core support structure assembly identified in MRP-227-A accounts for the XL lower core plate design at STP, Units 1 and 2. The applicant stated that there are no other alternate component substitutions within MRP-227-A at its site, and, therefore, it meets the requirements for application of MRP-227-A to manage age-related material degradation for reactor internal components. In its RVIIP, the applicant states that the lower support column bolts and lower support column bodies are not applicable to its XL lower core plate design. The staff noted that these are "Expansion" components. The staff also noted that the applicant has other "Expansion" components in its design that correspond to the "Primary" components for the lower support column bolts and lower support column bodies. Therefore, the applicant has additional "Expansion" components to inspect if aging degradation is found in the applicable "Primary" components. The staff finds the applicant's response to RAI 3.0.3.3.6-5 acceptable because the applicant justified that its lower core support assembly is consistent and bounded by the design assumptions in MRP-227-A. The staff's concerns in RAI 3.0.3.3.6-5 are resolved.

The staff finds the applicant's response to A/LAI No. 2 acceptable because the applicant identified the plant-specific design differences from the MRP reports and provided sufficient demonstration that the EPRI MRP's protocols for inspecting the components do not need to be altered or augmented beyond those recommended for the components in MRP-227-A. A/LAI No. 2 is resolved.

A/LAI No. 3. In this action item, the staff recommended that applicants applying the MRP-227-A methodology should perform a plant-specific analysis either to justify the acceptability of an applicant's or licensee's existing programs for its control rod guide tube (CRGT) support pins (split pins), or else identify changes to the programs that should be implemented to manage the aging of these components for the period of extended operation. The staff requested that the results of this plant-specific analysis and a description of the plant-specific program being relied upon to manage aging of the CRGT split pins should be submitted as part of the applicant's RVI AMP.

In its response to A/LAI No. 3, the applicant stated that the CRGT split pins (which were made from Alloy X-750 nickel-based alloy materials) were replaced during RFOs 1RE12 and 2RE11 (2005) with pins made from cold-worked 316 stainless steel materials and were qualified for a 60-year design life. The applicant concluded that additional inspection requirements are not currently needed for the replaced split pins because: (a) CRGT split pins made from cold-worked 316 stainless steel materials have been installed at other plants since 1997 and they have not exhibited any signs or indications of failure, and (b) since other plants replaced their pins sooner than STP, the inspections performed at the other plants will provide a leading indicator for managing crack-induced degradation in the CRGT spilt pins at STP.

The staff determined that some additional information was needed to clarify how the applicant would implement its process for collecting and assessing CRGT split pin inspection data in accordance with the PWR Reactor Internals Program. The staff noted that the applicant would also need to address inspections of the CRGT split pins if the components were defined as ASME Section XI Examination Category B-N-3 removable core support structure components.

By letter dated November 30, 2015, the staff issued RAI 3.0.3.3.6-6, Parts 1 and 2, to the applicant. In RAI 3.0.3.3.6-6, Part 1, the staff asked the applicant to identify the plants that will be performing inspections of their replaced Type 316 cold-worked CRGT split pins that the applicant will use as the lead operating experience for managing aging in the CRGT split pins at STP Units 1 and 2. The staff also asked the applicant to identify: (a) the process or processes that will be used in accordance with the "administrative controls" or "confirmation process" elements of the PWR Reactor Internals Program to collect and compile the inspection data from these plants, (b) the monitoring criteria that will be applied to the inspection data and implemented in accordance with the "monitoring and trending" program element of the AMP, and (c) the plant-specific "acceptance criteria" that will be used to assess such data and the "corrective actions" that will be taken if these acceptance criteria are not met.

In RAI 3.0.3.3.6-6, Part 2, the staff asked the applicant to clarify whether the replaced CRGT split pins at STP are categorized as ASME Section XI Examination Category B-N-3 components (i.e., ASME removable core support structure components). If the split pins are defined as ASME removable core support structure components, the staff asked the applicant to justify why the components would not need to be inspected and managed for aging using either the "Existing Program" criteria in the PWR Reactor Internals Program (LRA B.2.1.35) or the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program (i.e., the ISI Program in LRA Section B2.1.1).

By letter dated December 17, 2015, the applicant responded to RAI 3.0.3.3.6-6. The applicant stated that the replacement split pins were installed in accordance with the original equipment manufacturer recommendation, and therefore are dispositioned consistent with the recommendations in MRP-227-A. The applicant further stated that STP considers the industry operating experience through the MRP and the PWR Owners Group and will update its inspection plan for the split pins as needed and appropriate. The staff noted that the applicant's evaluation of the split pins is consistent with the basis in MRP-227-A and that the applicant provided an acceptable basis to not require plant-specific, augmented inspections. The staff further noted that the applicant will participate in current and future industry recommendations to manage these split pins for aging that will provide reasonable assurance that STP will update its AMP and aging management activities for the split pins based on future applicable operating experience. Also in its response, the applicant clarified that the CRGT split pins are defined as ASME Section XI, Examination B-N-3 components as part of the upper internals assembly. The applicant reviewed the implementation of MRP-227-A on its plant-specific ASME Section XI inspection requirements and determined there were no effects. The staff noted that the applicant's ASME Section XI inspection requirements are adequate to manage the effects of loss of material due to wear for the split pins. The staff finds the applicant's response to RAI 3.0.3.3.6-6 acceptable because: (1) the applicant justified its determination that the replacement Type 316 stainless steel split pins do not require augmented inspection, (2) the applicant reiterated that its aging management program considers industry operating experience and will incorporate appropriate updates to the aging management activities, and (3) the split pins are within the scope of the applicant's ASME Section XI inspection programs and will manage the effects of loss of material due to wear. Therefore, the staff accepts the staff's basis that the CRGT split pins will be managed for aging throughout the period of extended operation. The staff's concerns in RAI 3.0.3.3.6-6 and A/LAI No. 3 are resolved.

A/LAI No. 4. The action item request in A/LAI No. 4 is only applicable to the design of RVI components in Babcock and Wilcox-designed PWRs and does not apply to the design of the RVI components at STP. Because the RVI components at STP were designed by Westinghouse Electric Company, this item need not be addressed.

A/LAI No. 5. In this action item, the staff recommended that Westinghouse-design applicants for renewal should identify the plant-specific acceptance criteria to be applied to evaluations of the results of physical measurement techniques that will be applied to the RVI hold-down spring for the facility, as recommended in Table 5-3 of the MRP-227-A report. The staff recommended that the applicant include its proposed acceptance criteria and explain how the proposed acceptance criteria are consistent with both the plant's licensing basis and the need for maintaining the intended function of the hold-down spring under all licensing basis conditions of operation.

The applicant stated that the RVI hold-down springs at STP Units 1 and 2 are fabricated from Type 403 stainless steel materials and that hold-down springs made from this material were screened out as "No Additional Measures" components based on their inclusion as FMECA Group 1, Category A "low probability of failure" components in Table 7-2 of the MRP-191 report.

The staff noted that stress relaxation is the unloading of preloaded components due to long-term exposure to elevated temperatures (i.e., loss of preload is a thermally activated process). Thus, the staff finds it reasonable that at PWR operating temperatures, which are less than 400 °C, the stress relaxation of Type 403 stainless steel would also be lower than the stress relaxation of Type 304 stainless steel. The staff also noted that stress relaxation in springs fabricated from Type 403 stainless steel is not as likely to occur when compared to springs fabricated from Type 304 stainless steel because the higher yield stress in Type 403 stainless steel, which imparts improved resistance to loss of preload, may result from stress relaxation or irradiation assisted creep aging mechanisms. The staff confirmed that MRP-191 evaluated Type 403 hold-down springs and classified them as "No Additional Measures" components.

The staff finds that the applicant adequately addressed A/LAI No. 5 because the applicant demonstrated, and the staff confirmed, that the hold-down springs at STP are not fabricated from Type 304 stainless steel and because the applicant demonstrated that corresponding physical measurements do not need to be performed on the Type 403 martensitic stainless steel hold-down spring. Therefore, the staff's concerns in A/LAI No. 5 are resolved.

A/LAI No. 6. The action item request in A/LAI No. 6 is only applicable to the design of RVI components in Babcock and Wilcox-designed PWRs and does not apply to the design of the RVI components at STP. Because the RVI components at STP were designed by Westinghouse Electric Company, this item need not be addressed.

A/LAI No. 7. In A/LAI No. 7, the staff recommended that license renewal applicants for Westinghouse reactors should develop plant-specific analyses to demonstrate that lower support column bodies made from cast austenitic stainless steel (CASS), martensitic stainless steel, or precipitation hardened stainless steel materials will remain functional during the period of extended operation. The staff also recommended that these analyses should consider the possibility of loss of fracture toughness occurring in these components as a result of thermal aging and neutron irradiation embrittlement and should consider any limitations on accessibility of the components to inspection and the resolution and sensitivity of the inspection techniques that would be applied to these components. The staff recommended that: (a) the plant-specific analysis should be consistent with the plant's licensing basis and the need to maintain the functionality of the components being evaluated under all licensing basis conditions of operation, and (b) the applicant should include the plant-specific analysis as part of the PWR Reactor Internals Program that would be submitted in accordance with A/LAI No. 8, item (1) or the inspection plan that would be submitted in accordance with A/LAI No. 8, item (2).

The applicant stated that the upper support columns and column bases in the upper internals assemblies are comprised of CASS, Grade CF8 materials. The applicant stated that, based on chemistry data from the certified material test report (CMTRs) for the CF8 materials and the use of this data to calculate the percentage of delta ferrite in the materials, the potential for inducing loss of material due to thermal embrittlement is low for the CF8 CASS materials used to fabricate these components. Based on this data, the applicant concluded that the MRP-227-A basis for inspecting these components continues to remain valid without the need for adjustment.

The staff noted that the applicant's basis for resolving A/LAI No. 7 uses the criteria in NRC License Renewal Issue 08-0030 (dated May 19, 2000) as the basis for concluding that thermal aging embrittlement will not be an aging management issue for RVI upper internals assembly support columns or column bases. However, the staff determined that additional data were necessary to verify that thermal aging embrittlement will not be an aging issue of concern for these components during the period of extended operation. Therefore, by letter dated November 30, 2015, the staff issued RAI 3.0.3.3.6-8 to the applicant. In this RAI, the staff asked the applicant to provide the plant-specific delta-ferrite contents for the CASS CF8 materials used to fabricate upper internals assembly support columns or column bases, and the equational criteria and plant-specific chemistry alloy content data used to calculate the delta-ferrite contents of these components. As an alternative basis for resolving this issue (if applicable), the applicant may choose to demonstrate that these components were appropriately evaluated in MRP-227-A or the background reports for MRP-227-A and were placed into FMECA Category A and "No Additional Measures" categories based on the conclusions that there are no consequences on RVI component intended functions if these components fail to maintain their structural integrity.

By letter dated December 17, 2015, the applicant responded to RAI 3.0.3.3.6-8. In its response, the applicant stated that STP Unit 1 has 50 upper internals assembly – upper support columns, column bases that are comprised of CASS. The applicant stated that it reviewed the CMTRs to calculate the delta ferrite content of the CASS material. The applicant stated that when the element percentages of nitrogen and molybdenum were not found, 0.4 percent was used for nitrogen, per NUREG/CR-4513, and 0.5 percent for molybdenum was used, which is the maximum value as an input for Hull's formula. Based on these calculations, the applicant determined that 48 of the 50 components did not meet the ≤ 20% delta ferrite content acceptance criteria for susceptibility for thermal embrittlement. The applicant identified that 2 of the 50 components are potentially susceptible to thermal embrittlement. For STP Unit 2, the applicant applied the same analysis for the 50 upper internals assembly – upper support columns, column bases that are comprised of CASS. The applicant determined that all 50 of the components did not meet the ≤ 20% delta ferrite content acceptance criteria for susceptibility for thermal embrittlement. The applicant stated that the two CASS components that are potentially susceptible to thermal embrittlement at STP Unit 1 were screened in for the material degradation effects of thermal embrittlement. However, with the consideration of thermal embrittlement, the MRP-227-A ranked the upper internals assembly – upper support columns, column bases that are comprised of CASS, Grade CF8 material into the "No Additional Measures" category. The staff noted that the applicant used a conservative approach when calculating the delta ferrite content of the CASS components by using conservative values of nitrogen and molybdenum when the actual values could not be determined. The staff noted that the STP's disposition of the upper internals assembly – upper support columns, column bases as "No Additional Measures" components is consistent with the basis in MRP-227-A. The staff finds the applicant's response acceptable because: (a) the applicant provided its methodology for calculating the delta ferrite contents of the CASS upper internals components and used conservative values when appropriate, and (b) the applicant provided its basis for dispositioning the CASS upper internals components as "No Additional Measures" components consistent with MRP-191 and MRP-227-A. The staff's concerns in RAI 3.0.3.3.6-8 and A/LAI No. 7 are resolved.

A/LAI No. 8, Subitem (1). In this A/LAI, the staff recommended that that PWR applicants for renewal submit an AMP in the LRAs that addresses the 10 AMP program elements for aging management of PWR RVI components in GALL Report AMP XI.M16A, "PWR Vessel Internals."

The applicant updated LRA AMP B2.1.35, "PWR Reactor Internals," to be consistent with the program elements in GALL Report AMP XI.M16A, "PWR Vessel Internals," as given in LR-ISG-2011-04 and submitted this plant-specific AMP in the letter of June 30, 2015. Based on submittal of this AMP, the staff finds that the applicant meets the recommended request in A/LAI No. 8, subitem (1). The staff's concerns in A/LAI No. 8, subitem (1) are resolved.

A/LAI No. 8, Subitem (2). In this A/LAI, the staff recommended that, to ensure the MRP-227-A program and the plant-specific action items will be carried out by PWR license renewal applicants, the applicant should submit an inspection plan that addresses the identified plant-specific action items for staff review and approval consistent with the licensing basis for the plant.

The applicant stated that the PWR Reactor Internals Program (B2.1.35) is described in LRA Section A1.35 and LRA Section B2.1.35 and that the RVIIP is included in LRA Appendix C and addresses plant-specific action items and does not identify any deviations to MRP-227-A. The staff confirmed that the applicant submitted its RVIIP for staff review in the letter of June 30, 2015. Based on submittal of this AMP, the staff finds that the applicant met the recommended request in A/LAI No. 8, subitem (2). The staff's concerns in A/LAI No. 8, subitem (2) are resolved.

A/LAI No. 8, Subitem (3). In this A/LAI, the staff stated that 10 CFR 54.21(d) requires that an FSAR supplement for the facility contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation.

The applicant included its UFSAR supplement for the PWR Reactor Internals Program in LRA Appendix A, Section A1.35. Based on submittal of this AMP, the staff finds that the applicant met the recommended request in A/LAI No. 8, subitem (3). A/LAI No. 8, subitem (3) is resolved. The staff's evaluation of the UFSAR supplement for the PWR Reactor Internals Program is given later in this SER section.

A/LAI No. 8, Subitem (4). The regulation in 10 CFR 54.22 requires each license renewal applicant to submit any TS changes (and the justification for the changes) that are necessary to manage the effects of aging during the period of extended operation as part of its LRA. In A/LAI No. 8, subitem (4) the staff recommended that, for those plant CLBs that include mandated inspection or analysis requirements for the RVI components either in the operating license for the facility or in the facility TS, the applicant should perform a comparison of the mandated licensing requirements to the inspection criteria defined in the MRP-227-A report. The staff stated that, if the mandated requirements differ from the recommended criteria in MRP-227-A report, the applicable license conditions or TS requirements take precedence over the MRP recommendations and must be complied with.

In response to this A/LAI, the applicant stated that no changes of the TS are necessary. The staff reviewed the operating licenses for STP Units 1 and 2 and the plant TS for operating license conditions or TS requirements that relate to aging management bases for the RVI components in the plant design. The staff did not note any specific operating license or TS requirements related to design or integrity of the RVI components at STP. The staff also did not find any operating license or TS requirements for the STP that would need to be amended as a result of the applicant's plans to implement the augmented inspection criteria in the MRP-227-A report or the inservice inspections that are required by 10 CFR 50.55a and the ASME Code Section XI to be performed on those RVI components that are defined in the CLB as ASME Section XI, Examination Category B-N-3 core support structure components or Examination Category B-N-2 interior attachment components such as the clevis insert bolts.

Based on this review, the staff finds that the applicant addressed the request in A/LAI No. 8, subitem (4) because the staff has confirmed that: (a) the CLB does not include any operating license conditions or TS requirements that relate to the design or structural integrity of the applicant's RVI components, and (b) the CLB does not include any operating license conditions or TS requirements that would need to be amended as a result of the applicant's plans to implement the augmented inspection criteria in the MRP-227-A report. The staff's concerns in A/LAI No. 8, subitem (4) are resolved.

A/LAI No. 8, Subitem (5). The regulation in 10 CFR 54.21(c)(1) requires applicants to identify all analyses in the CLB for their RVI components that conform to the definition of a TLAA in 10 CFR 54.3. The MRP-227-A report does not specifically address the resolution of TLAAs that may apply to a PWR license renewal applicant's RVI components. Therefore, in A/LAI No. 8, subitem (5), the staff recommended that PWR license renewal applicants that reference and will be implementing the recommendations in the MRP-227-A report should evaluate the CLB for their facilities to determine if they have any plant-specific TLAAs for the RVI components that need be addressed. If so, the staff recommended that the applicants submit the applicable TLAAs for NRC review along with the AMPs that will be used to implement the MRP-227-A report recommended activities for RVI components at their facilities.

The staff also stated that, for those CUF analyses on RVI components that are TLAAs, the applicant may use the PWR Reactor Internals Program as the basis for accepting these TLAAs in accordance with 10 CFR 54.21(c)(1)(iii) only if the RVI components within the scope of the CUF analyses are periodically inspected for fatigue-induced cracking in the components during the period of extended operation. The staff stated that the periodicity of the inspections of these components requires adequate justification to resolve the TLAA. Otherwise, the staff recommended that the acceptance of these TLAAs shall be done in accordance with either 10 CFR 54.21(c)(1)(i) or (ii), or in accordance with 10 CFR 54.21(c)(1)(iii) using the applicant's program that corresponds to GALL Report AMP X.M1, "Fatigue Monitoring." The staff also stated that the evaluation requirements of ASME Code Section III, Subsection NG-2160 and NG-3121, require the existing fatigue CUF analyses to include the effects of the RCS water environment.

In its response to A/LAI No. 8, subitem (5), the applicant stated that the applicable TLAAs for the RVI components are the metal fatigue analyses that have been identified in LRA Section 4.3.3. The applicant stated that it does not credit the PWR Reactor Internals Program as the basis for accepting these TLAAs in accordance with the criteria in 10 CFR 54.21(c)(1)(iii) or for managing the effects of fatigue-induced cracking in these components during the period of extended operation.

According to LRA Section 4.3.3, the CLB includes the following RVI components that have been analyzed with metal fatigue TLAAs: (a) lower core support plate, (b) baffle and former assemblies, (c) core barrel assemblies, (d) radial keys and clevis inserts, (e) upper core support assemblies, (f) upper core plates, (g) upper support columns, and (h) instrumentation port column assemblies. The staff noted that, in the letter of June 30, 2015, the applicant confirmed through Commitment No. 34 that the AMP in LRA Section B3.1, "Metal Fatigue of Reactor Coolant Pressure Boundary," will be used to accept these TLAAs in accordance with TLAA acceptance criterion in 10 CFR 54.21(c)(1)(iii) and to manage the effects of fatigue-induced cracking on the intended functions of these components during the period of extended operation. The program elements of AMP B3.1 include criteria for monitoring the impacts of EAF on the acceptability of the CUF analyses for RCPB components, but does not specifically state that the same criteria will be applied to the CUF analyses for the specific RVI components, as identified in LRA Section 4.3.3.

By letter dated November 30, 2015, the staff issued RAI 3.0.3.3.6-9 to the applicant requesting resolution of this issue. Specifically, the staff asked the applicant to clarify whether the program element criteria in LRA AMP B3.1, "Metal Fatigue of Reactor Coolant Pressure Boundary," for monitoring and managing the effects of EAF on the CUF analyses for RCPB components will be extended to those RVI components that have been analyzed with a CUF analysis. If not, the applicant was asked to clarify how the impacts of EAF will be evaluated or managed for those RVI components that have been analyzed in accordance with a CUF analysis.

By letter dated December 17, 2015, the applicant responded to RAI 3.0.3.3.6-9. In its response, the applicant clarified that the Metal Fatigue of Reactor Coolant Pressure Boundary program will manage the effects of EAF for the RVI components as well. The applicant amended the application to specify that the program will be enhanced to monitor and trend the fatigue usage of selected, plant-specific bounding EAF locations at RVI locations in addition to the RCPB locations. The staff reviewed the amended program description and noted that the applicant provided the appropriate updates to the LRA. The staff finds the applicant's response acceptable because the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary program will manage the fatigue usage of the applicable RVI locations such that effects of EAF will be managed during the period of extended operation. The staff's concerns in RAI 3.0.3.3.6-9 are resolved.

<u>Summary</u>. Based on the staff's review above, the staff concludes that the PWR Reactor Internals Program satisfies the recommendations of the SRP-LR and GALL Report Table IV.B2 for the PWR internals under the aging mechanisms identified earlier, and is consistent with the guidance of MRP-227-A. Hence, working with appropriate AMP(s), as specified in the GALL Report, Table IV.B2, the applicant's PWR Internals Program is acceptable for management of aging effects listed above for the RV internals.

<u>Operating Experience</u>. LRA Section B2.1.35 summarizes the operating experience related to the PWR Reactor Internals Program. The applicant noted that there have been relatively few reports of incidents involving aging degradation of PWR RV internals in the United States. However, European PWRs have reported a significant amount of PWR RV internals aging degradation, particularly in baffle-former bolting components. The staff reviewed operating experience information in the application to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant. The applicant plans to manage future aging-related degradation of its PWR RV internals by the implementation of MRP-227-A, "Material Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines," and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program requirements.

By letter dated July 6, 2014, the staff issued RAI B2.1.35-1, Part 2, to the applicant. In this RAI, the staff asked the applicant to clarify whether the cracking experience with clevis insert bolts at another U.S. PWR was applicable to the design of the clevis insert assemblies and bolts at STP Units 1 and 2. The staff also asked the applicant to clarify how the clevis insert assemblies and bolts at STP were designed and fabricated (including specific details on any heat treatments that were used to fabricate the bolts) and to identify those ASME Section XI inspections that were performed on the bolts in the past. The staff also asked the applicant to clarify whether the past inspections of the bolts have revealed any indications of cracking in the bolts. Based on this information, the staff asked the applicant to justify whether the "Existing Program" protocols for visually inspecting the clevis insert bolts on a 10-year inservice inspection interval would need to be altered for the applicant's program.

The applicant responded to the request in RAI B2.1.35-1, Part 2, in the applicant's letter of June 30, 2015, and provided an updated operating experience evaluation of the clevis insert assemblies at STP Units 1 and 2. The applicant determined that the clevis insert bolts at STP were made from Alloy X-750 nickel alloy materials that were subjected to equalization and solution heat treatments. The applicant stated that the bolts could be susceptible to PWSCC. The applicant stated that it performs inspections of the clevis insert assemblies and bolts in accordance with the existing inservice inspection requirements for ASME Section XI Examination Category B-N-2 components, which require VT-3 visual inspections of the accessible areas of the assemblies and bolts on a 10-year frequency basis. Based on its review of the application and RAI responses, the staff finds the response acceptable because the applicant appropriately evaluated plant-specific and industry operating experience. The staff's concerns in RAI B2.1.35-1, Part 2, are resolved. The staff noted that the "operating experience" program element satisfies the criteria in SRP-LR Section A.1.2.3.10.

<u>UFSAR Supplement</u>. LRA Section A1.35 provides the UFSAR supplement for the PWR Reactor Internals Program. By letters dated February 27, 2012, and March 28, 2012, the applicant revised the LRA to reflect a commitment to follow the guidance of EPRI 1022863 (MRP-227-A). The staff reviewed the UFSAR supplement against the recommended description for this type of program, as described in SRP-LR Table 3.1-1, and determined that the information in the supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

The applicant committed (Commitment No. 27) to implement the new PWR Reactor Internals Program within 24 months after the issuance of EPRI 1022863, "PWR Internals Inspection and Evaluation Guideline, (MRP-227-A)," and to follow the inspection plan guidance of EPRI 1016609, "Inspection Standard for PWR Internals, (MRP-228)." MRP-227-A was issued on January 9, 2012.

<u>Conclusion</u>. On the basis of its review of the applicant's PWR Reactor Internals Program, the staff determines that this AMP is a plant-specific program designed as a means for fulfilling Commitment No. 27 and is consistent with MRP-227-A. The staff concludes that the applicant demonstrated that the effects of aging for the RV internals 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).

3.0.3.3.3 Selective Leaching of Aluminum Bronze

<u>Summary of Technical Information in the Application</u>. LRA Section B2.1.37, as amended by letter, dated March 30, 2017, describes the existing Selective Leaching of Aluminum Bronze Program as being plant-specific. The LRA states that the AMP addresses aluminum bronze (copper alloy with greater than 8 percent aluminum) components and welds exposed to raw water to manage the effects of loss of material due to selective leaching.

The LRA also states that the AMP proposes to manage this aging effect for aboveground components through external visual inspections for dealloying in all susceptible aluminum bronze components, volumetric examinations, destructive examinations, and time-of-flight-diffraction (TOFD) ultrasonic (UT) wall thickness measurements (when necessary). For buried piping with aluminum bronze welds, periodic yard walkdowns in the vicinity of the buried piping will be performed to look for changes in ground conditions that would indicate leakage.

Staff Evaluation. The Selective Leaching of Aluminum Bronze Program has been significantly revised from the version that was submitted in the original LRA. The staff's evaluation of the originally proposed program and applicant's responses to RAIs dated through October 4, 2012, is documented in the Safety Evaluation Report with Open Items Related to the License Renewal of South Texas Project Units 1 and 2, (SER with Open Items) dated February 15, 2013 (ADAMS Accession No. ML13045A356). This section evaluates only those applicant's submittals that pertain to the revised program.

Staff's Conclusions in Regard to Percent Dealloying and Dealloyed Material Properties. By letter dated March 30, 2017, the applicant committed (Commitment No. 44) to replace all the aluminum bronze castings susceptible to selective leaching (i.e., dealloying). Prior to the applicant committing to replace the castings, the staff reviewed the applicant's aging management activities associated with the susceptible aluminum bronze castings and made determinations on two topics: (1) the percent dealloyed and (2) the dealloyed material properties. The following is based on the staff's review of the applicant submittals, another licensee submittal on selective leaching of aluminum bronze components, and the staff's review of literature in regard to these two topics. The below information documents the staff's conclusions.

1. Percent Dealloyed: The dealloying of aluminum bronze is driven by electrochemical processes[3] and occurs locally at the interface of the susceptible phases and the aqueous environment (e.g., brackish emergency core cooling water). The dealloying mechanism in aluminum bronze alloys is not controlled by the bulk diffusion rate of the aluminum in the copper matrix.[4,5] The dealloying mechanism involves the dissolution of the susceptible phase followed by the redisposition of the more noble copper. Metallurgical work conducted by the applicant, showing that the dealloyed regions of its cast components are primarily

[3] Heidersbach R. 1968. "Clarification of the Mechanism of the Dealloying Phenomenon," *CORROSION* 24(2):38-44.

[4] Pryor M.J., Fister J.C. 1984. "The Mechanism of Dealloying of Copper Solid Solutions and Intermetallic Phases," *Journal of the Electrochemical Society* 131(6):1230–1235.

[5] Baboian, R. Ed. 2005. Corrosion Tests and Standards: Application and Interpretation-Second Edition, Chapter 24, MNL20-2ND-EB, ASTM International, West Conshohocken, PA, 2005.

comprised of voids, high-purity copper, and unaffected phases, supports the local dissolution and redisposition mechanism.[6,7,8]

It is important to establish that the dealloying process occurs locally at the interface between the alloy and the environment, as opposed to being dependent on bulk diffusion and occurring at distances exceeding the grain size when quantifying the percent dealloyed. Dealloying progresses along a front that may be considered to scale with the grain size. The dealloying process behind this front has gone to completion (fully dealloyed or 100 percent dealloyed). The dealloying process ahead of this front has not commenced (as-received condition or zero percent dealloyed). Based on its review, the staff determined that, on the microstructural level, dealloying has either gone to completion or has not occurred. Thus the term "percent dealloyed" does not apply to aluminum bronze at the microstructural level because there are not varying degrees of dealloying.

The term "percent dealloyed" at the component level refers to the percent geometrically dealloyed. The percent geometrically dealloyed is the ratio of the dealloyed area to the cross-sectional area of the component. The dealloyed area is determined optically at low magnification after destructive examination or mechanical testing. Methods have been established for revealing dealloyed regions so that they can be easily observed visually.[9] The applicant provided descriptions of how it determined the percent geometrically dealloyed.[10,11] The inherent assumption in determining the percent geometrically dealloyed in this manner is that, on an engineering scale, the alloy only exists in two discrete conditions: as-received and fully dealloyed. Based on its review, the staff determined that it is reasonable to treat the material as two discrete conditions and calculate the percent geometrically dealloyed in this manner based on its review of publicly available literature on the topic, documents reviewed during the supplemental audits conducted at the applicant's facility, and the applicant's metallurgical analysis. Thus, the term "percent dealloyed' applies at the component level and the percent geometrically dealloyed varies.

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[6] Powell G.T. July 31, 2014. "South Texas Project, Units 1 and 2, Response to Requests for Additional Information for the Review of the South Texas Project, Units 1 and 2, License Renewal Addiction - Set 26 (TAC ME4936 and ME4937)" (ADAMS Accession No. ML14224A151)

[7] Powell G.T. 7/29/2015. "South Texas Project, Units 1 and 2 - Response to Request for Additional Information for the Review of License Renewal Application - Set 31." (ADAMS Accession No. ML15222A248)

[8] Powell GT. May 31, 2016. "South Texas Project, Units 1 and 2, Additional Information for the Review of the License Renewal Application – Aluminum Bronze AMP (TAC Nos. ME4936 and ME4937)." (Accession No. ML16155A131)

[9] MIL-STD-2195A, Department of Defense Test Method: Inspection Procedures for Detection and Measure of Dealloying Corrosion on Aluminum Bronze and Nickel-Aluminum Bronze Components, December 7, 1993. Available at <http://everyspec.com/MIL-STD/MIL-STD-2000-2999/MIL-STD-2195A_17126/>.

[10] Powell G.T. 10/4/2012. "South Texas Project, Units 1 and 2, Response to Requests for Additional Information for Review of License Renewal Application – Aluminum Bronze, Set 23 (TAC Nos. ME4936 and ME4937)" (ADAMS Accession No. ML122920722).

[11] Powell G.T. July 31, 2014. "South Texas Project, Units 1 and 2, Response to Requests for Additional Information for the Review of the South Texas Project, Units 1 and 2, License Renewal Addiction – Set 26 (TAC ME4936 and ME4937)" (ADAMS Accession No. ML14224A151).

Based on its review, the staff determined that the term “fully dealloyed” means that dealloying has gone to completion in the specific material being evaluated. It does not mean that all of the aluminum has been removed from the volume, nor does it mean that the entire volume of susceptible phases (gamma-2, beta) have dealloyed. Phases in aluminum bronze alloys that are not susceptible to dealloying will be unaffected as the dealloying front moves past them. These non-susceptible phases will retain their as-received morphology and aluminum content within the dealloyed volume. Also, susceptible phases that are completely surrounded by non-susceptible phases are isolated from the aqueous environment and will not dealloy. Isolated clusters of unaffected susceptible phases in fully dealloyed volumes have been observed in aluminum bronze components removed from service at the applicant’s facility.[12] The characteristics of the fully dealloyed microstructure are directly dependent on the as-received microstructure, which is a result of the material processing and composition.[13]

Additionally, it should be recognized that the percent geometrically dealloyed is determined using two-dimensional area measurements; although, the dealloyed region is a three-dimensional volume. When determining the extent of dealloying using cross-sectional information, consideration should be given to the number of sections and their orientation relative to the component. An inadequate number of sections or an overly simplistic evaluation of the sections may produce non-conservative estimates of the extent of dealloying.

In summary, the staff has determined that:

(a) At the microstructural level, the dealloying process is confined to a localized front that scales with the grain size. The material on either side of the dealloying front is either in the as-received or fully dealloyed condition. The three-dimensional shape of this front may be complex. The term “percent dealloyed’ is not applicable at the microstructural level.

(b) At the component level, the term “percent dealloyed” refers to the percent of the component cross-section that is fully dealloyed. Optical techniques at low magnification are adequate to identify the percent geometrically dealloyed on a given plane of a material. Additional precautions need to be taken to ensure that two-dimensional measurements are conservative and appropriate for their intended use.

2. <u>Dealloyed Material Properties</u>: Components may be partially geometrically dealloyed; however, the material within the component is in either an as-received or fully dealloyed condition (e.g., a component that is 70 percent geometrically dealloyed will have 70 percent of its wall thickness in fully dealloyed condition and the remaining 30 percent of its wall thickness in the as-received material condition). Therefore, the only mechanical properties of relevance are those

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[12] Attachment 1 – Response To Request for Additional Information for Alternative Request IR-3-17, for ASME Section XI for Repair/Replacement of Class 3 Service Water System Valves (ADAMS Package Accession No. ML14041A174).

[13] Upton B. 1963. “Corrosion Resistance in Seawater of Medium Strength Aluminum Bronzes.” *CORROSION* 19(6):204t-209t.

determined using specimens that are 0 percent or 100 percent geometrically dealloyed. Mechanical properties for 0 percent dealloyed (as-received) materials are standardized and readily available. The applicant conducted testing to determine the mechanical properties for its dealloyed aluminum bronze castings.[14] The staff found additional mechanical property data for the relevant alloys to expand the available data set.[15,16] The available test data demonstrates that the dealloyed material retains some degree of mechanical properties. Based on the staff's review, lower bound values for the mechanical properties of dealloyed material have not been established. Therefore, the staff estimated the lower bound tensile and yield strength values of the dealloyed material using the procedures established in "Department of Defense Handbook: Metallic Materials and Elements for Aerospace Vehicle Structures" [17] and the statistical constants from "Tables for One Sided Statistical Tolerance Limits."[18] The staff estimated the lower bound tensile and yield strength values of the dealloyed material to be effectively 0 ksi based on standard industry methods to develop material properties. Material properties cannot be established with a limited data set as provided by the applicant.

The staff reviewed the mechanical test data for dealloyed aluminum bronze castings and determined that the dealloyed material should be given no credit for mechanical properties when determining structural integrity. This determination is consistent with previous staff evaluations.[19]

Statistical evaluations such as those described in "Department of Defense Handbook: Metallic Materials and Elements for Aerospace Vehicle Structures"[9] are appropriate for determining lower bound mechanical properties for standardized materials. It should be recognized that any methodology used to establish lower bound mechanical properties for dealloyed material needs to account for the fact that it is not a standardized material produced using standardized methods. Additionally, the staff identified the following challenges associated with evaluating or expanding the currently available data set:

- The limited size of the available data set makes the statistical significance of any derived value uncertain.

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[14] Powell G.T. July 31, 2014. "South Texas Project, Units 1 and 2, Response to Requests for Additional Information for the Review of the South Texas Project, Units 1 and 2, License Renewal Application – Set 26 (TAC ME4936 and ME4937)" (ADAMS Accession No. ML14224A151).

[15] Grecheck E.S. March 28, 2013. "Millstone, Unit 3, Alternative Request IR-3-17 to ASME Section XI for Repair/Replacement of Class 3 Service Water System Vaves (ADAMS Accession No. ML13091A038).

[16] Beck J.G., Pugh C.R., Dwivedy K.K.. Means K.H. (Ed.). 1995. Residual life of an aluminum-bronze valve. United States: American Society of Mechanical Engineers.

[17] MIL HDBK 5J. 2003. "Department of Defense Handbook: Metallic Materials and Elements for Aerospace Vehicle Structures," January 31, 2003.

[18] ONR Report AD1418179. 1957. "Tables for One Sided Statistical Tolerance Limits," November 1, 1957.

[19] Beasley, B. September 4, 2014. "Millstone Power Station, Unit No. 3 – Relief from the Requirements of the ASME Code Section XI, Requirements for Repair/Replacement of Class 3 Service Water Valves (Tac No. MF1314) (ADAMS Accession No. ML14217A203).

- The large degree of scatter in the currently available data may necessitate a large number of specimens to draw meaningful conclusions.
- The limited amount of dealloyed material available for testing makes expanding the data set difficult.
- The use of non-standard mechanical test specimen sizes may lead to uncertainty when interpreting results.
- Elimination of invalid test results that potentially resulted from lower than expected mechanical properties may produce nonconservative results.
- Variability in the as-received material and subsequent dealloying process may produce a non-typical property distribution. In order for the dealloyed front to progress through the microstructure, it must be in contact with the aqueous environment; therefore, the voids in the dealloyed volume must form an interconnected network. This interconnected network of voids, which results in a porous material, is directly dependent on the variability in the as-received material and subsequent dealloying process.

In summary, the staff further determined that:

(c) The applicant has not established lower bound mechanical properties for dealloyed aluminum bronze and that no strength or fracture toughness credit should be given to dealloyed material.

By letter dated March 30, 2017, the applicant revised the program and committed to replace all susceptible components (see further discussion in the staff's evaluation of the "scope of program" program element below). As a result, upon entry into the period of extended operation, the only susceptible material in the plants will be a significant number of welds. By letter dated May 31, 2016, the applicant submitted a basis document to support the proposed method to manage loss of material for these welds. The staff's evaluation of these letters follow.

Basis of the Program. As is discussed in the staff's evaluation of the "scope of program" program element, with the removal of cast components susceptible to selective leaching, the only susceptible materials are pipe-to-pipe welds joining wrought pipe and weld repair areas of extruded tees. In its basis document dated May 31, 2016, the applicant postulated that:

- The root pass of the welds is less susceptible to dealloying due to the dilution of aluminum and the cool down rate as compared to subsequent passes.
- The lower susceptibility of the root pass results in a barrier to through-wall penetration of dealloying.
- As long as there are no construction-related or service-induced defects in the root pass, dealloying should not proceed through the root pass and into subsequent passes.

In its response to RAI B2.1.37-3 Part (c), dated May 31, 2012, the applicant described the progression of dealloying as follows:

- "[t]hrough-wall leakage/seepage is caused by the progression of dealloying through the wall. Leakage can result from dealloying only, or from a combination of dealloying and crack propagation. In most cases, cracking initiates at pre-existing weld flaws and imperfections typically at the weld root or heat-affected zone under the backing ring."
- "[t]he mechanism for crack extension is believed to be continued dealloying along the crack front which drives the crack subcritically through the wall by the combination of reduction in toughness at the crack tip, service, and weld residual stress."

The applicant stated that, based on plant-specific operating experience, the only welds that leaked are those with backing rings, and weld leakage has not occurred since 1994. The applicant also stated that an extensive series of volumetric and surface nondestructive examinations were conducted during the latter portions of initial construction.

The staff reviewed the May 31,2016, technical basis letter including: historical leakage data, test results for weld microstructure and chemical analyses, computational estimates of cooling rates after welding, examination results showing phase distribution within successive weld layers, leakage rate analyses, allowable flaw sizes related to leakage rates, and a comparison of weld and cast microstructures. The staff could not substantiate all of the positions postulated by the applicant due to the limited amount of data and resulting fidelity of the analysis. However, there was sufficient information to postulate that the root pass of the welds is less susceptible to dealloying. The Selective Leaching of Aluminum Bronze Program is based on extensive inspections and examinations to be conducted on susceptible materials, and related acceptance criteria and corrective actions, in order to substantiate the claim that root pass of the welds is less susceptible to dealloying.

The applicant's program uses one-time and periodic visual and volumetric inspections as well as destructive examinations to provide assurance that: (a) welds do not have defects of sufficient size to promote dealloying in the root pass and subsequent passes; (b) dealloying (beyond superficial levels) is not occurring in the welds; (c) if cracks are present in the welds, they are not accompanied by dealloying (beyond superficial levels); and (d) if dealloying in the root pass is occurring, the phase distribution demonstrates that a continuous path of dealloying or susceptible phases (beta, gamma-2) is not present.

Scope of Program. As amended by letter dated March 30, 2017, LRA Section B2.1.37 states that the Selective Leaching of Aluminum Bronze Program manages loss of material due to selective leaching for aluminum bronze (copper alloy with greater than 8 percent aluminum) components and welds exposed to raw water within the scope of license renewal. The applicant also stated that the buried piping material is not susceptible to selective leaching (due to the low aluminum content); however, the filler metal in the welds is susceptible. The applicant further stated that prior to the period of extended operation; the following items will be replaced:

- all aluminum bronze castings, including attachment welds, susceptible to selective leaching
- aluminum bronze root valves with adapter socket welds
- extruded piping tees with weld repairs of a sufficient size such that failure of the repair would affect the structural integrity of the tee.

The applicant stated that the size of the extruded tee weld repairs will be determined by review of the vendor record of nonconformance. Where sufficient information is not available in the vendor record of nonconformance, the applicant will review past radiography film or the tee will be radiographed to characterize the weld repair size.

In its January 12, 2017, letter, the applicant stated that there would be approximately 678 aboveground welds with backing rings, 816 aboveground welds without backing rings, 357 below-ground welds with backing rings, and 1,586 below-ground welds without backing rings that would be susceptible to loss of material due to selective leaching. These numbers were provided to put into perspective sample sizes stated by percentage, as described in the "detection of aging effects" and "corrective actions" program elements.

The staff reviewed the applicant's "scope of program" program element against the criteria in SRP-LR Section A.1.2.3.1, which state that the scope of the program should include the specific components, the aging of which the program manages.

The staff noted that the applicant identified the component types, material, and environment covered by this program. The staff also noted that based on a review of plant-specific operating experience, the applicant identified for replacement the types of piping components that have experienced through-wall penetration since 1994.

The staff finds the applicant's "scope of program" program element to be adequate because the applicant: (a) provided information that clearly identifies the scope of components, materials, and environments covered by the program, and (b) will replace the three component types cited above with non-susceptible material prior to the start of the period of extended operation.

Based on its review of the application, the staff confirmed that the "scope of program" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.1 and, therefore, the staff finds it acceptable.

Preventive Actions. As amended by letter dated March 30, 2017, LRA Section B2.1.37 states that the Selective Leaching of Aluminum Bronze Program does not prevent degradation due to aging effects, but is instead a condition monitoring program. However, the external surfaces of buried aluminum bronze piping are coated.

The staff reviewed the applicant's "preventive actions" program element against the criteria in SRP-LR Section A.1.2.3.2, which state: (a) if the program is not a preventive or mitigation program, the information need not be provided and (b) the activities for prevention should be described.

The staff finds the applicant's "preventive actions" program element to be adequate because for aboveground piping, the program is based on condition monitoring and the coatings on buried piping can isolate the external surfaces of susceptible material from the aggressive environment.

Based on its review of the application, the staff confirmed that the "preventive actions" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.2 and, therefore, the staff finds it acceptable.

Parameters Monitored or Inspected. As amended by letter dated March 30, 2017, LRA Section B2.1.37 states that the Selective Leaching of Aluminum Bronze Program will include one-time volumetric examinations of welds without backing rings, periodic volumetric examinations of welds with backing rings, destructive examinations of welds with and without backing rings, periodic yard walkdowns to detect changes in ground conditions that could be indicative of leakage, periodic visual inspection of all aboveground welds to detect leakage, and visual inspections of coatings on buried piping when excavated in accordance with the Buried Pipe Program. A surface examination will be conducted on buried piping in the vicinity of degraded coatings. The applicant also stated that:

- Loss of material, which is also referred to as selective leaching, will be monitored through system walkdowns, destructive examinations, and surface examinations in the vicinity of degraded buried coatings.
- If acceptance criteria are not met, one-time and periodic TOFD UT examinations will be conducted to detect the extent of dealloying in susceptible aluminum bronze welds.
- Cracking associated with selective leaching will be monitored by the volumetric and destructive examinations.
- Phase distribution is monitored through destructive examination.

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: (a) the program should identify the aging effects that the program manages and provide a link to the parameters that will be monitored; and (b) the parameter monitored or inspected should be capable of detecting the presence and extent of aging effects.

The staff finds the applicant's "parameters monitored or inspected" program element to be adequate because the conditions that are conducive to loss of material due to selective leaching (e.g., weld cracks, phase distribution) will be monitored by volumetric and destructive examinations, which are capable of detecting cracks, interrogating phase distributions in the welds, and detecting the extent of dealloying within a weld. In addition, loss of material due to selective leaching will be directly detected during destructive examinations and indirectly by visual inspections during walkdowns to detect aboveground or buried piping leakage. Surface examinations are capable of detecting loss of material due to selective leaching. Given the acceptance criteria and corrective actions associated with the one-time and periodic volumetric examinations and destructive examinations, the use of visual inspections for indications of leakage from buried and aboveground piping will provide reasonable assurance that loss of material due to selective leaching will be detected prior to a loss of intended function of the essential cooling water piping.

In order to obtain additional information on the TOFD UT examination technique, the staff conducted an audit commencing in January 2017 (ADAMS Accession No. ML17107A319). During the audit, the staff noted:

- The use of the method was validated by conducting TOFD UT examinations followed by destructive examination to confirm that the extent of degradation had been sufficiently detected by the examination technique.
- The applicant's plant-specific procedures include: (a) qualification requirements for examiners and examiners that interpret the data; (b) the equipment to be used for the inspections; (c) essential variables for the inspections; (d) details on how to conduct the inspections; and (e) requirements for data analysis and recording.

- A technical justification was provided, which meets a Low Rigor level of qualification conducted in accordance with the 2004 Edition of ASME Code Section V, “Nondestructive Examination,” Article 14, “Examination System Qualification.”

The staff finds that the use of the TOFD UT examination technique, as qualified by the applicant, can provide reasonable assurance that the extent of dealloying in susceptible aluminum bronze welds can be characterized because: (a) a technical justification for the process was conducted using industry consensus methods, and (b) the plant-specific procedure has sufficient controls such that it can provide accurate and repeatable results. The staff would not normally accept a Low Rigor level of qualification for a nondestructive examination technique to conduct examinations on safety-related components. The staff accepted this method in this instance because: (a) the examinations are not within the scope of ASME Code Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components;” (b) the level of detail in the applicant’s plant-specific implementation procedures is adequate to conduct the inspections; (c) the results of the validation samples demonstrate that dealloying can be quantified; and (d) TOFD is the most effective known nondestructive examination technique for detecting the dealloying aging effect. The staff’s evaluation of the use of the TOFD UT examination technique (e.g., quantity of inspections, timing) is documented in the “corrective actions” program element because the method will only be implemented as a result of not meeting acceptance criteria for destructive examinations or structural integrity analyses.

Based on its review of the application, the staff confirmed that the “parameters monitored or inspected” program element satisfies the criteria defined in SRP-LR Section A.1.2.3.3 and, therefore, the staff finds it acceptable.

Detection of Aging Effects. As amended by letter dated March 30, 2017, LRA Section B2.1.37 states that the Selective Leaching of Aluminum Bronze Program will include:

- Visual inspections of all aboveground welds will be conducted every 6 months to detect potential leakage.
- Yard walkdowns will be conducted every 6 months to detect indications of leakage.
- Visual inspections of the exterior coating of buried piping will be conducted when it is excavated. Followup surface examinations are conducted when degraded coatings are detected.
- One-time volumetric inspections of 20 percent (up to a maximum of 25) of the welds with no backing rings will be conducted prior to the period of extended operation to detect weld defects. The applicant stated that if a weld indication that does not meet acceptance criteria is found, periodic volumetric inspections of 20 percent of the welds (with a maximum of 25) will be conducted every 10 years.
- Volumetric inspections of 20 percent of the welds (up to a maximum of 25) will be conducted prior to the period of extended operation to detect weld defects. The inspections will be conducted prior to the period of extended operation and every 10 years thereafter.
- Destructive examinations on 20 percent (up to a maximum of 25) of the aboveground welds without backing rings and 20 percent (up to a maximum of 25) of the aboveground welds with backing rings will be conducted prior to the period of extended operation.

- Inspection locations for the volumetric inspection and destructive examinations will be selected based on variability of construction, size distributions, structural integrity margins, and consequence of failure.

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 program should describe: (a) how the program element will be capable of detecting the occurrence of age-related degradation prior to the loss of the current licensing basis intended function(s) of in-scope components; (b) the when, where, and how data are collected; and (c) the basis of the sample size and location selection.

The staff noted the following.

- Several sampling-based GALL Report AMPs (e.g., AMP XI.M33, AMP XI.M38) cite that a representative sample size is 20 percent of the population up to a maximum of 25 components.
- Welds without backing rings and the welds with backing rings represent two distinct populations. The welds without backing rings are more likely to have a susceptible microstructure because there is less dilution in the weld and the cool down rates would be slower, both of which are conditions that promote the formation of phases susceptible to dealloying (beta and gamma-2). The welds with backing rings have a more aggressive environment due to the crevice created by the backing ring.
- Welds with higher heat input due to configuration and ease of welding (e.g., horizontal weld versus vertical weld), could be more susceptible to formation of susceptible phases.

Evaluation of Detectability of Buried Pipe Leakage. As documented in the SER with Open Items dated February 13, 2016, the staff reviewed the basis for the leakage rate from buried components that would be detectable on the surface at grade elevation. In the initial LRA, the applicant did not provide a sufficient basis for why changes in ground conditions proposed in LRA Section B2.1.37 would be sufficient to detect selective leaching on internal surfaces of buried aluminum bronze welds prior to a loss of the components' ability to meet their intended function(s) consistent with the CLB for the period of extended operation.

During the audits and subsequent evaluation of this program, the staff reviewed several calculations that were intended to demonstrate that leaks in susceptible buried piping welds could be detected on the surface of the ground during periodic yard walkdowns. The staff could not conclude that the applicant's calculation for detecting a buried pipe weld leak adequately addressed the potential for leakage to preferentially travel along the interface between the soil and pipe or along compaction seams. In addition, the staff did not understand how buried pipe leakage would be detected when the surface is paved or lined with stone. By letter dated September 21, 2011, the staff issued RAI B2.1.37-2 Part (5), requesting that the applicant state the basis for why leakage from buried ECW piping will not preferentially travel down the interface between the soil and pipe or along compaction seams or revise the calculation to account for this phenomenon. The staff also asked the applicant to state the basis for being able to detect leakage where the ground level surface is stone or paved in locations where there are susceptible buried welds.

In its response dated December 8, 2011, the applicant stated that:

- Most of the piping has 15 feet of safety-class compacted soil overburden, making the existence of a preferential leakage travel path of significant length highly unlikely.
- The thin layer of gravel that exists does not significantly impede detection because it is very porous.
- Leakage in gravel areas would flow toward storm drainage catch basins, which are included in the inspection program.
- Leaks in potable water and fire protection piping have been detected in gravel areas.
- Only a small portion of the travel path is paved, consisting of fairly narrow plant roads.
- Each site has a building that is located over the piping and a perforated pipe leading to a nearby catch basin was installed between the building floor slab and the piping.
- The system is capable of performing its intended function with a 1,000 gpm leakage rate and the detectable leakage rate is 10 gpm.
- The progression rate of dealloying is slow; therefore, delay in detection is not critical.

The staff finds the applicant's response acceptable for RAI B2.1.37-2 Part (5) for the following reasons:

- The compacted soil overburden reduces the amount of flow that would travel down the length of the pipe, because the leaking fluid would move upwards due to the back pressure gradient decreasing as the water rises to the surface.
- The detectable leak size (10 gpm) is 1 percent of the plant-specific 1,000 gpm system leakage criterion; therefore, based on the slow growth rate of dealloying, the detectable level of leakage would be acceptable.
- A leak that originated beneath gravel and paved areas is detectable because (a) the area covered by paving is relatively small, (b) neither gravel nor paved areas will impede flow to drain basins, and (c) the inspection scope includes drain basins.

The staff's concern described in RAI B2.1.37-2 Part (5) is resolved.

Based on the staff's review of Table 12, "Summary of Leakage Rates and Margins for Faulted Loads," in the basis document date May 31, 2016, the staff noted that 30-inch discharge side tees have a very small margin (ratio of 1.01) between the size of the leak necessary to obtain the flow rate that will reach the surface and the allowable flaw size. By letter dated July 28, 2016, the applicant stated that it reviewed the original analyses and determined that there were input values associated with the stress analyses that could be revised to provide a more realistic estimate of the margin between the size of the leak necessary to obtain the flow rate that will reach the surface and the allowable flaw size. As a result of these changes, the applicant stated that the ratio was improved from 1.01 to 1.54. Based on its review of Table 12 and the above input, the staff concluded that the use of more realistic input values can demonstrate greater margins between the leakage detection capability and the minimum required flow for the system to perform its intended function consistent with the CLB for the period of extended operation.

It was not clear to the staff that the leak rate calculation accounted for the potential resistance of the coating on the buried piping. By letter dated July 28, 2016, the applicant stated that it reviewed the impact of the coating on the leak rate calculation. The applicant stated that:

(a) the piping is coated with coal tar epoxy and the weld joints are wrapped using a Tapecoat® CT wrap; and (b) the manufacturer stated that the tape, “will not be able to resist the operating pressure if there is a leak. Water from a small leak could get trapped under the coating [tape], but since the component is only coated [with tape] on the weld joints it would quickly work its way out to the edge of the coating.” The staff concludes that there is reasonable assurance that the leak will propagate to the surface with minimal impact on the duration that the leak would not be detected because: (a) based on industry operating experience through-wall leaks in buried piping are routinely detected on the surface despite most buried pipes being coated; (b) the detectable leak size of 10 gpm is much smaller than the plant-specific loss rate criterion of 1,000 gpm; (c) the increase in margin between the size of the leak necessary to obtain the flow rate that will reach the surface and the allowable flaw size, described in the previous paragraph should provide sufficient margin given the typical slow growth of dealloying; (d) leak detection is based on the instantaneous occurrence of the 10 gpm leakage size flaw, whereas in actuality the flaw would grow and begin to leak before this condition occurs; and (e) based on the staff’s review of plant-specific documents, the crack opening displacements used for the leak rate calculations omit the plastic contribution (i.e., deformation) to the crack opening displacement, this being conservative because it under predicts the crack size, resulting in smaller leaks.

In summary, the staff concludes that there is reasonable assurance that a buried pipe leak will be detected at ground surface elevation prior to a loss of intended function of the essential cooling water system.

The staff finds the applicant’s “detection of aging effects” program element to be adequate (based on its review of the May 31, 2016, basis document and program changes) because:

- The volumetric and destructive examinations are capable of detecting the conditions that are conducive to loss of material due to selective leaching (e.g., weld cracks, phase distribution).
- The quantity of volumetric and destructive examinations is consistent with other AMPs that use a sampling-based methodology to detect aging effects.
- The welds to be inspected use similar material and are exposed to the same environment. As a result, a random sample using construction and size considerations can provide assurance that a representative population will be examined.
- The acceptance criteria and associated corrective actions for the volumetric and destructive examinations provide assurance that the basis for the program (e.g., root pass is less susceptible, the lower susceptibility results in a barrier to through-wall penetration of dealloying) can be confirmed.
- The basis of the program, routine visual inspections to detect through-wall leakage can provide assurance that loss of material due to selective leaching will not progress to the point where a loss of intended function of the essential cooling water system (ECWS) will occur.
- For buried piping, there is a sufficient margin between the detectability of a leak and the flow rate necessary to meet the intended function of the ECWS.
- Followup surface examinations of buried piping in the vicinity of degraded coatings can be effective at detecting loss of material due to selective leaching.
- The TOFD UT method can characterize the extent of dealloying in susceptible aluminum bronze welds.

Based on its review of the application, the staff confirmed that the “detection of aging effects” program element satisfies the criteria defined in SRP-LR Section A.1.2.3.4 and, therefore, the staff finds it acceptable.

Monitoring and Trending. As amended by letter March 30, 2017, LRA Section B2.1.37 states that the Selective Leaching of Aluminum Bronze Program will maintain a history of the volumetric, TOFD UT, and destructive examination results. Following completion of these examinations, the results will be reviewed to determine if an adverse trend is identified.

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 the results should be evaluated against the acceptance criteria to effect timely corrective or mitigative actions.

The staff finds the applicant’s “monitoring and trending” program element to be adequate because reviewing the cumulative results of the volumetric and destructive examinations will provide insights sufficient to confirm the basis of the program.

Based on its review of the application, the staff confirmed that the “monitoring and trending” program element satisfies the criteria defined in SRP-LR Section A.1.2.3.5 and, therefore, the staff finds it acceptable.

Acceptance Criteria. As amended by letter dated March 30, 2017, LRA Section B2.1.37 states that the Selective Leaching of Aluminum Bronze Program includes the following acceptance criteria:

- For volumetric examinations, “no detected planar indication that is surface connected (exposed to the ECW environment) unless the depth of the indication is contained within the 80% of the weld root pass region. An indication not connected to the surface (not exposed to the ECW environment) is acceptable.”
- For visual inspections during walkdowns, no visible through wall leakage or indications of surface water in the vicinity of buried essential cooling water piping will be indicative of through-wall leakage.
- For destructive examinations: (a) “no loss of material due to selective leaching penetrating 80% of the root-pass region;” (b) “selective leaching is non-propagating (surrounded by a resistant phase distribution); and (c) “[t]he microstructure of the weld root region shall exhibit[s] a resistant phase distribution consistent with the metallurgical technical basis report.” Acceptance criteria for buried piping coatings is described in the Buried Piping and Tanks Inspection Program.
- For the extent of loss of material in the vicinity of degraded coatings for buried piping, “upon removal of the selective leaching the minimum wall thickness is maintained.”
- For TOFD UT examinations, “no loss of material due to selective leaching resulting in not meeting ASME Section XI Code required margins imposed by ASME [Code] Section XI structural factors for normal/upset and emergency/faulted conditions.”

The applicant also stated that if an acceptance criterion is not met, the condition will be documented in the CAP.

The staff reviewed the applicant's "acceptance criteria" program element against the criteria in SRP-LR Section A.1.2.3.6, which states that the acceptance criteria of the program and its basis should be described and the acceptance criteria should ensure that the component's intended function(s) are met.

Based on its review of the May 31, 2016, basis document, the staff noted that loss of material due to selective leaching became apparent due to through-wall leakage in the late 1980s. As stated earlier in this SER section, the last leak through a weld in wrought iron pipe occurred in 1994.

The staff finds the applicant's "acceptance criteria" program element to be adequate because:

- Limiting planar indications and dealloying to 80 percent of the weld root pass region can provide reasonable assurance that dealloying will not progress through the root pass and into the more susceptible region of the weld.
- Either 20 percent of all welds up to a maximum of 50 (i.e., 25 without backing rings, 25 with backing rings) will be destructively examined. This provides a representative sample of welds sufficient to establish a trend of whether flaws have approached the 80 percent of the root pass region.
- The acceptance criterion that an indication that is not connected to the inside surface of the pipe is acceptable given that this flaw is not exposed to the environment that can promote selective leaching.
- For destructive examinations, consistent with the basis document, the criteria provides reasonable assurance that loss of material due to selective leaching will not penetrate past the root (less susceptible) pass.
- For buried piping with degraded coatings, the criterion of meeting minimum wall thickness is acceptable because the wall thickness loss can be quantified and upon returning the piping to service, new coatings will be applied.
- The use of ASME Code Section XI structural factors provides sufficient margin to establish structural integrity.

Based on its review of the application, the staff confirmed that the "acceptance criteria" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.6 and, therefore, the staff finds it acceptable.

<u>*Corrective Actions*</u>. As amended by letter dated March 30, 2017, LRA Section B2.1.37 states that when welds that do not meet weld indication acceptance criteria or exhibit through-wall leakage are detected:

- The weld will be removed and destructively examined to determine the extent of cracking, the extent of selective leaching, and the microstructural phase distribution.
- Five additional volumetric examinations for each weld not meeting acceptance criteria will be performed until no additional weld indications that do not meet the acceptance criteria are found.
- A structural integrity analysis will be performed to confirm that the load carrying capacity of the welds that remain in operation are adequate to support the intended function of the ECWS through the period of extended operation.

- An AMP effectiveness evaluation will be performed to determine program changes necessary to manage the effects of aging.

The applicant stated that, if a destructive examination does not meet the acceptance criteria due to a weld indication; however, the weld meets structural integrity acceptance criteria:

- Five TOFD UT examinations will be conducted for each weld not meeting acceptance criteria. The examinations will be completed within 60 days of identification that the acceptance criteria was not met. Inspections will continue until no additional welds not meeting acceptance criteria are found.
- Periodic TOFD UT will be conducted every 5 years on welds that were not removed and previously found to not meet acceptance criterion but met structural integrity capability. These welds will be examined until three consecutive examinations identify no additional propagation of the selective leaching.
- Perform periodic TOFD examinations will be performed on an additional 10 percent sample of the remaining aboveground weld types every 5 years.
- The sample will be selected from the "total population of aboveground welds associated with the weld type (with or without backing ring) consider[ing] construction, size distributions, structural integrity margins, and consequence of failure."
- A structural integrity analysis will be performed on welds that do not meet acceptance criteria to confirm that the load-carrying capacity of the welds that remain in operation are adequate to support the intended function of the ECWS through the period of extended operation.
- An AMP effectiveness evaluation will be performed to determine program changes necessary to manage aging.

The applicant stated that, if the results of a structural integrity evaluation do not meet acceptance criteria, and the weld can be declared operable per the plant-specific Operability, Functionality, and Reportability procedure, the following will be conducted:

- An extent of condition evaluation will be conducted to identify other locations requiring examination. The additional examinations will be focused on stress margin locations less than or equal to that of the structurally unacceptable weld.
- TOFD UT examination will be performed on the remaining aboveground weld population using a sample with a 95/95 confidence until no additional weld indication not meeting the TOFD UT examination acceptance criteria is found.
- The TOFD UT examinations will be sequenced as follows:
  - "[t]he weld population used to determine the 95/95 confidence sample will be based on the above ground weld types (with or without backing rings) and locations that would not meet code allowable margins when evaluated against the failed components degraded load carrying capability."
  - Examinations are prioritized by examining the weld locations with the least structural integrity margin and with the highest consequence of failure first.
  - Planning and preparations for performing TOFD UT extent of condition examinations will commence upon discovery of one weld not meeting structural integrity.

- Examinations will commence at the next ECW train outage and will sequence through all the ECW trains during each ECW train outage with at least 20 percent of the examinations being completed within 30 days.
- All the examinations will be completed within 180 days.

- If a second weld is found that does not meet TOFD UT acceptance criteria:
  - An examination plan, schedule and bases for the examination of the remaining above ground welds will be developed.
  - TOFD UT examinations will be performed on 100 percent of the remaining above ground welds to determine extent of condition with at least 20 percent being completed within 30 days and the remainder completed within 180 days
  - An evaluation of the below-ground weld margins to identify locations requiring inspection will be performed. "[t]he evaluation will focus on below ground locations where structural integrity could be challenged based on the relative stress margins and the inspection results obtained on the above ground structurally unacceptable weld(s)."

- Periodic 95/95 confidence sample TOFD UT examinations will be conducted every 5 years on the remaining welds which have not been TOFD UT examined.
- Samples will be selected from, "the total population of above ground welds associated with the weld type (with or without backing ring), considering variability of construction, size distributions, structural integrity margins, and consequence of failure."
- Monthly aboveground walkdowns of the aluminum bronze welds to verify no through-wall leakage is occurring will be performed.
- Monthly yard walkdowns to verify no through-wall leakage is occurring will be performed.
- Repair or replacement of the susceptible weld(s) based on the cause of the structural integrity evaluation failure, results of the additional TOFD UT examinations and the extent of condition.

The applicant stated that, if the results of a structural integrity evaluation do not meet acceptance criteria and either: (a) the weld would be declared inoperable per the plant-specific Operability, Functionality, and Reportability procedure or (b) for welds that have been removed, the weld would have been declared inoperable if still installed, the following will be conducted:

- TOFD UT examinations will be conducted on 100 percent of the remaining aboveground weld population.
  - Examinations are prioritized by examining the weld locations with the least structural integrity margin and with the highest consequence of failure first.
  - Planning and preparations for performing TOFD UT extent of condition examinations will begin upon discovery of one weld not meeting structural integrity.
  - Examinations will begin at the next ECW train outage and will sequence through all the ECW trains during each ECW train outage with at least 20 percent of the examinations being completed within 30 days.
  - All the examinations will be completed within 180 days.

- Belowground weld margins will be evaluated to identify locations requiring inspection. The evaluation will consider below ground locations where structural integrity could be challenged based on the relative stress margins and the inspection results obtained on the above ground structurally unacceptable weld(s). Below ground welds where the evaluation shows that the structural integrity could challenge operability will be examined using TOFD UT during the next scheduled refueling outage.
- Aboveground walkdowns and yard walkdowns will be conducted twice a month.
- The susceptible weld(s) will be repaired or replaced based on the cause of the structural integrity evaluation failure, results of the additional TOFD UT examinations, and the extent of condition.

The applicant stated that, when degraded buried pipe coatings are detected and there is evidence of loss of material due to selective leaching, the dealloyed material will be removed and the piping repaired or replaced if the as-left wall thickness is unacceptable.

In its response to RAI B2.1.37-8 dated January 12, 2017, the applicant provided the following margins for buried pipe as compared to above ground pipe:

- For 30-inch pipe, stress levels are approximately one-half that for buried pipe compared to aboveground pipe.
- For 30-inch pipe, the limiting through-wall flaw for buried pipe is 1.96 times that for aboveground pipe.
- For 10-inch pipe, stress levels are approximately one-third that for buried pipe compared to aboveground pipe.
- For 10-inch pipe, the limiting through-wall flaw for buried pipe is 1.83 times that for aboveground pipe.

The staff reviewed the applicant’s “corrective action” program element against the criteria in SRP-LR Section A.1.2.3.7, which states that actions to be taken when the acceptance criteria are not met should be described in appropriate detail or referenced to source documents and if corrective actions permit analysis without repair or replacement, the analysis should ensure that the structure- and component-intended function(s) are maintained consistent with the current licensing basis.

The staff finds the applicant’s “corrective actions” program element to be adequate because:

- Welds that do not meet acceptance criteria due to leakage or weld defects are replaced.
- One-time and periodic additional inspections will be conducted to provide insights related to the extent of condition.
- Structural integrity analysis will be performed to determine if the as-found condition would have met ASME Section XI Code required margins.
- Sample locations selection is based on the likelihood of loss of material due to selective leaching (e.g., construction configuration) and potential consequences (e.g., structural integrity margins, consequence of failure).
- Conditions that do not meet acceptance criteria will provide insights into potential changes to the Selective Leaching of Aluminum Bronze program.

- If a weld is found to not meet structural integrity requirements, increasing the frequency of aboveground and yard walkdowns to monthly or twice a month (depending on the operability results) provides additional assurance that potentially leaking welds will be detected sooner.
- The additional inspections conducted, depending on the degree of degradation are appropriate because:
  - Where a weld does not meet acceptance criteria, but it meets structural integrity requirements, conducting five additional volumetric inspections and five TOFD UT examinations for each weld that does not meet acceptance criteria is consistent with the expansion criteria in Generic Letter 90-05, "Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3 Piping" for though-wall leaks detected in systems similar to the ECWS.
  - If the results of a structural integrity analysis do not meet acceptance criteria; however, the weld can be demonstrated to be operable, conducting TOFD UT examinations on a 95/95 sample of the remaining aboveground welds (buried welds are addressed below) provides a sufficient population of examination results to determine the extent of potential adverse results.
  - If the results of a structural integrity analysis do not meet acceptance criteria and operability criteria is not being or would not have been met, or two welds that do not meet TOFD acceptance criteria are detected, conducting TOFD UT examinations on 100 percent of the aboveground susceptible welds provides a sufficient population to detect similarly degraded welds or demonstrate that there are no other aboveground welds that could affect the intended function of the ECW system.
  - Structural integrity requirements will still be met because the slow growing nature of selective leaching is demonstrated by conducting periodic TOFD UT inspections every 5 years on: (a) welds that were not removed and previously found to not meet acceptance criteria but met structural integrity requirements; and (b) a 95/95 confidence sample on the remaining welds that have not been TOFD UT examined when the results of any structural integrity analyses did not meet acceptance criteria; however, the weld can be demonstrated to be operable.
  - Performing three consecutive TOFD UT examinations for inservice welds that did not meet acceptance criteria can effectively characterize whether further loss of material due to selective leaching is occurring.
  - The timing of the additional inspections (e.g., 20 percent of the TOFD examinations being completed in 30 days and the remainder in 180 days) is acceptable because: (a) the ECW system has three trains, which provide higher redundancy than most plants that only have two trains; and (b) the initial followup sample provides a significant number of data points to understand the potential extent of the degraded condition.

For buried welds, the staff noted that there is almost a two times margin between the defect tolerance sizes for buried welds as compared to aboveground welds. This provides assurance that there is a reduced potential for buried welds to be found that do not meet structural integrity requirements and do not meet operability. In addition, the applicant's extent of condition TOFD UT examinations, upon detecting an aboveground weld that does not meet structural integrity requirements, will provide a significant amount of data in relation to potential extent of buried pipe loss of material due to selective leaching. The applicant proposes to conduct evaluations of flaw tolerance for buried pipe welds when degraded but operable aboveground welds are detected and inspections of potentially challenged buried welds when degraded but inoperable welds are detected (conducted by the next refueling outage). Based on the above, the staff finds that the applicant's proposal to take corrective actions for buried pipe welds and its CAP provide assurance that buried pipe welds will meet their intended function.

Based on its review of the application, the staff confirmed that the "corrective actions" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.7 and, therefore, the staff finds it acceptable.

Operating Experience. LRA Section B2.1.37 summarizes operating experience related to the Selective Leaching of Aluminum Bronze Program. The applicant stated that plant-specific operating experience indicates that through-wall dealloying has been observed in aluminum bronze components. The applicant also stated that it has analyzed the effects of the through-wall dealloying and found that the degradation is slow, so that rapid or catastrophic failure is not a consideration, and it has determined that the leakage can be detected before the flaw reaches a limiting size that would affect the intended functions of the ECW and ECW screen wash system.

The staff reviewed this information against the SRP-LR Section A.1.2.3.10 acceptance criteria that state that operating experience with existing programs should be discussed. This information should provide objective evidence to support the conclusion that the effects of aging will be adequately managed so that the intended functions of the SCs will be maintained consistent with the CLB during the period of extended operation.

The staff noted that the applicant used its plant-specific operating experience to recognize that a specific program was needed to address ongoing selective leaching of susceptible aluminum bronze components. During its review, the staff identified operating experience for which it determined the need for additional information, and it resulted in the issuance of an RAI, as discussed below. Based on a review of LRA Section B2.1.37 and documents available during the AMP audit, the staff lacked sufficient information to understand the extent of dealloying that is occurring in the ECW system. By letters dated September 21, 2011; and December, 18, 2012, the staff issued RAIs B2.1.37-1 Part (2) and RAI B2.1.37-5 Part (g), respectively, requesting that the applicant provide a list of all instances of selective leaching that has been detected and characterize the extent of dealloying as determined by the inspections and testing that has been conducted.

In its responses dated December 8, 2011; and December 18, 2012, the applicant provided a list of all dealloying data from 1987 to the present in the response, Table 1, "ECW Dealloying Data," including date of discovery, component type, metallurgical examination information (when available), and location.

The staff finds the applicant's response acceptable because the applicant provided comprehensive information on all instances of dealloying at STP. Based on the staff's review, the data provide a sufficient understanding of the extent of dealloying. The staff's concern described in RAI B2.1.37-1 Part (2) and RAI B2.1.37-5 Part (g), is resolved.

During the audit, the applicant provided a document titled, "ECW Dealloying and Weld Crack Data Tables Clarification." By letter dated April 12, 2012, the staff issued RAI B2.1.37-3 Part (j), requesting that the applicant submit this document on the docket. In its response dated

May 31, 2012, the applicant provided this information in Attachment B to enclosure 1. This attachment provided further clarifying details on flaw characterization, particularly those with crack morphology. The staff finds the response to this RAI acceptable because the information completed the staff's understanding of which flaws were as a result of only dealloying and which also had accompanying cracking. The staff's concern described in RAI B2.1.37-3 Part (j), is resolved.

During its review of plant-specific operating experience, the staff noted a crack that occurred downstream of a butterfly valve. The staff could not determine if this crack was associated with dealloying. By letter dated April 12, 2012, the staff issued RAI B2.1.37-3 Part (f), requesting that the applicant state whether dealloying was associated with this crack. In its response dated May 31, 2012, the applicant stated the following:

> The root cause of the cracking mechanism which occurred downstream of butterfly valves was wall thinning by a cavitation mechanism due to throttling valve operation. Metallographic examination did not reveal any evidence of dealloying corrosion or micro-segregation in the weld, heat affected zone, or base metal. All six outside diameter initiated, circumferential fatigue cracks and one inside diameter initiated axial fatigue crack were the secondary cracks that resulted from through-wall cavitation. There was no evidence of manufacturing defects involved in the failure.

The staff finds the applicant's response acceptable because it confirmed that the crack was not associated with dealloying. The staff's concern described in RAI B2.1.37-3 Part (f), is resolved. The staff's evaluation of cavitation erosion occurring in the ECW system is documented in SER Section 3.0.3.2.6.

During its review of plant-specific operating experience associated with the ECW system, the staff noted that cavitation erosion is occurring in the system. The staff did not know if any of the cavitation erosion has occurred or could occur in the vicinity of dealloying. If cavitation erosion could occur in the vicinity of dealloyed material, the staff does not know how the potential change in the rate of erosion is accounted for in the intervals between inspections of the components. By letter dated July 26, 2012, the staff issued RAI B2.1.37-4 Part (8), requesting that the applicant state whether cavitation erosion in the ECW system has or could occur in the vicinity of dealloying. If so, the staff requested that the applicant state how the potential change in the rate of erosion is accounted for in the intervals between inspections of the components.

In its response dated October 4, 2012, the applicant stated:

> Cavitation erosion in the ECW system has occurred within the valve body of the Component Cooling Water heat exchanger discharge valve and the downstream piping. The valve body is susceptible to dealloying and cavitation erosion. The downstream piping also experiences cavitation erosion, but the pipe material is not subject to dealloying. Both locations are coated to minimize material wear and are visually inspected periodically. Adjustment to the inspection interval is performed as necessary following each inspection to account for potential changes in erosion and available margins to assure minimum wall thicknesses are not compromised between inspections. Cavitation erosion of these locations are managed by the Open-Cycle Cooling Water System [AMP].

The staff finds the applicant's response acceptable because, even though the valve is susceptible to dealloying, it is coated. Coating the internals of the valve will eliminate the potential for dealloying to occur because the material is not in contact with water. In addition, the valve's coatings are inspected as part of the Open-Cycle Cooling Water System AMP. The staff's concern described in RAI B2.1.37-4 Part (8) is resolved.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its review of the application, and review of the applicant's responses to RAIs B2.1.37-1 Part (2), B2.1.37-3 Part (f), RAI B2.1.37-3 Part (j), B2.1.37-4 Part (8), and B2.1.37-5 Part (g), the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience, 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 criteria in SRP-LR Section A.1.2.3.10 and, therefore, the staff finds it acceptable.

UFSAR Supplement. As amended by letter dated March 30, 2017, LRA Section A1.37 provides the UFSAR supplement for the Selective Leaching of Aluminum Bronze Program. For plant-specific programs, Table 3.0-1 states that "[t]he program should contain information associated with the bases for determining that aging effects will be managed during the period of extended operation."

The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1.

The staff also noted that the applicant committed (Commitment No. 44), as amended by letter dated May 2, 2017, to implement the new Selective Leaching of Aluminum Bronze Program prior to entering the period of extended operation for managing aging of applicable components.

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its technical review of the applicant's Selective Leaching of Aluminum Bronze Program, the staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.4 Protective Coatings Monitoring and Maintenance Program

Summary of Technical Information in the Application. LRA Section B2.1.39 describes the existing Protective Coating Monitoring and Maintenance Program as plant-specific. The LRA also states that the program manages loss of coating integrity for Service Level 1 coatings inside containment so that the intended functions of post-accident safety systems that rely on water recycled through the containment sump/drain system are maintained consistent with the CLB. The applicant stated that the program includes visual examination of all reasonably accessible Service Level 1 coatings inside containment. The applicant further stated that this program does not include coatings that are insulated or otherwise enclosed in normal service and concrete receiving a non-film forming clear sealer coat only.

In a letter dated February 27, 2012, the applicant amended this AMP. The program description was revised to include discussions that state that the program is consistent with the standards provided in ASTM D5163-08, "Establishing Procedures to Monitor the Performance of Coating Service Level I Coating Systems in an Operating Nuclear Power Plant," and RG 1.54, dated October 2010, as addressed in GALL Report AMP XI.S8, "Protective Coating Monitoring and Maintenance Program." In addition, the applicant stated that physical tests are performed by individuals trained in accordance with ASTM D5498, "Standard Guide for Developing a Training Program for Personnel Performing Coating Work Inspection for Nuclear Facilities."

<u>Staff Evaluation</u>. 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 program elements follows. The staff's review of the "corrective actions," "confirmation process," and "administrative controls" program elements is documented in SER Section 3.0.4.

<u>*Scope of Program*</u>. LRA Section B2.1.39 states that the Protective Coating Monitoring and Maintenance Program includes a visual examination of all reasonably accessible Service Level 1 coatings inside containment, as defined in RG 1.54. This scope includes coatings applied to the steel containment liner, structural steel, supports, penetrations, uninsulated equipment, and concrete walls and floors receiving epoxy surface systems. The applicant stated that this program covers containment interior and equipment, structures, or components that are permanently located inside the containment.

The staff reviewed the applicant's "scope of program" program element against the criteria in SRP-LR Section A.1.2.3.1, which state that the scope of the program should include the aging management of specific SCs.

The staff noted that the program includes Service Level 1 coatings inside containment, including those applied to the steel containment liner, structural steel, supports, penetrations, uninsulated equipment, and concrete walls and floors receiving epoxy surface systems. The staff finds the applicant's "scope of program" program element to be adequate because proper maintenance of Service Level 1 coatings inside containment is essential to ensure operability of post-accident safety systems that rely on water recycled through the containment sump and drain system.

Based on the review of the application, the staff confirmed that the "scope of program" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.1; therefore, the staff finds it acceptable.

<u>*Preventive Actions*</u>. LRA Section B2.1.39 states that the program does not prevent aging effects but provides measures for monitoring to detect aging prior to loss of intended function. The applicant stated that coatings are not credited for preventing loss of material.

The staff reviewed the applicant's "preventive actions" program element against the criteria in SRP-LR Section A.1.2.3.2, and finds it acceptable.

Parameters Monitored or Inspected. LRA Section B2.1.39 states that the Protective Coating Monitoring and Maintenance Program inspects coated surfaces for flaking, blistering, cracking, delamination, peeling, or rusting. The section also states that any areas of coating discoloration or areas where corrosion has formed under the coating system are documented and evaluated.

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 state that for a condition monitoring program, the "parameters monitored or inspected" program element should be capable of detecting the presence and extent of aging effects.

The staff reviewed the applicant's "parameters monitored or inspected" program element and determined that additional information is needed to adequately evaluate this element. The staff noted that the LRA does not state the specific standards used to perform coating assessments (e.g., ASTM D5163). In addition, the frequency of Service Level 1 coating inspections seemed to be inconsistent with the recommendations of the GALL Report (i.e., every refueling outage). In RAI B2.1.39-1, dated February 8, 2012, the staff asked the applicant to provide the standards or guidance used (e.g., ASTM standards) to perform coating assessments. The staff also asked the applicant to discuss the frequency of coating inspections and explain how this frequency is consistent with the GALL Report.

In its response dated February 27, 2012, the applicant stated that coating condition assessments are performed consistent with the standards provided in ASTM D5163-08 and RG 1.54, and coating inspections are conducted during every refueling outage. The staff noted that the program uses ASTM D5163 and RG 1.54 to monitor degradation of Service Level 1 coatings prior to loss of intended function. In addition, the applicant revised the "parameters monitored or inspected" program element to include performance of inspections on any visible defect (i.e., blistering, cracking, flaking, peeling, rusting, physical damage).

The staff finds the applicant's "parameters monitored or inspected" program element to be acceptable because the program uses ASTM D5163 and RG 1.54, which provide guidelines that are acceptable to the staff for establishing an inservice coatings monitoring program for Service Level 1 coating systems. In addition, performing coating inspections every refueling outage is consistent with the GALL Report. Furthermore, inspection of any visible defect is acceptable because corrective actions can be taken to maintain coating integrity. The staff's concern described in RAI B2.1.39-1 is resolved.

Based on the review of the application, and review of the applicant's responses to RAI B2.1.39-1, the staff confirmed that the "parameters monitored or inspected" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.3; therefore, the staff finds it acceptable.

Detection of Aging Effects. LRA Section B2.1.39 states that the program periodically conducts condition assessments of Service Level 1 coatings inside containment as part of the ASME Section XI, Subsection IWE Program and the Structures Monitoring Program at intervals not exceeding 5 years. The applicant stated that visual inspection of coatings in containment is intended to characterize the condition of the coating systems. The applicant also stated that, in some cases, a complete inspection is not possible because of inaccessibility. Coating systems are characterized based on an inspection of coating systems that are reasonably accessible or based on a representative sample. The applicant also stated that if localized areas of degraded coatings are identified, those areas are evaluated and scheduled for repair or replacement, as necessary.

In a letter dated February 27, 2012, the applicant provided a revised program basis document, which removed discussion of ASME Code Section XI and stated that visual inspections of Service Level 1 coatings are conducted every refueling outage. The applicant also stated that personnel qualifications, inspection plans, inspection methods, and inspection equipment are consistent with the requirements in ASTM D5163. The applicant stated that destructive and nondestructive tests are performed on an as-needed basis, as determined by the Nuclear Coatings Specialist or Coatings Planner. The applicant stated that the Coatings Planner meets the qualification for a Nuclear Coatings Specialist in accordance with ASTM D7108-05, "Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist." Furthermore, the applicant indicated that the Coatings Inspector is certified in accordance with ASTM D5498. Both ASTM D7108 and D 5498 are called out in ASTM D5163, which is an acceptable standard per the GALL Report.

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 state that detection of aging effects should occur before there is loss of intended function(s) of structure(s) or component(s).

The staff noted that the program calls for inspection of Service Level 1 coatings every outage and that inspections are based on a representative sample. The staff finds the applicant's "detection of aging effects" program element adequate because inspecting every refueling outage would provide adequate assurance that there is proper maintenance of the protective coatings. In addition, the method of performing the coatings inspection is acceptable because visual inspections are performed and these visual inspections are able to detect adverse coating conditions.

Based on the review of the application, the staff confirmed that the "detection of aging effects" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.4; therefore, the staff finds it acceptable.

Monitoring and Trending. LRA Section B2.1.39 states that the program inspector reviews previous coating condition assessment reports. The applicant stated that the inspection reports prioritize repair areas as either needing repair during the same outage or as postponed to future outages. The applicant also stated that the containment liner plate is inspected as part of the ASME Section XI, Subsection IWE Inspection Program. The applicant indicated that the results of this inspection are reviewed to assist in identifying areas of degraded or damaged coatings.

In its letter dated February 27, 2012, the applicant provided additional information and stated that a pre-inspection review is performed on the previous two monitoring reports, and repair areas are prioritized as either needing repair during the same outage, needing repair during the next available outage, or monitored and re-evaluated in the next available outage in accordance with ASTM D5163. Furthermore, the applicant stated that a standardized coatings condition assessment report includes the identification of coatings found intact with no defects identified, identification of coatings that were not inspected, and the reason why the inspection cannot be conducted. The coatings condition assessment report includes written or photographic documentation or both of coating inspection areas, failures, and defects. In addition, discussion on ASME Code Section XI was removed.

The staff reviewed the applicant's "monitoring and trending" program element against the criteria in SRP-LR Section A.1.2.3.5, which state that monitoring and trending activities should be described, should provide predictability of the extent of degradation, and should effect timely corrective or mitigative actions.

The staff noted that the applicant will prioritize repair areas as either needing repair during the same outage, postponed to future outages, or monitored and re-evaluated in the next available outage. The staff finds the applicant's "monitoring and trending" program element to be adequate because the method in which the applicant evaluates identified degradation is acceptable and because degraded coatings assessed for repairs are made in accordance with ASTM D5163. The staff considers ASTM D5163 acceptable because it provides guidelines for establishing an adequate inservice coatings monitoring program for Service Level I coating systems in operating nuclear power plants.

Based on the review of the application, the staff confirmed that the "monitoring and trending" program element satisfies the criteria in SRP-LR Section A.1.2.3.5; therefore, the staff finds it acceptable.

Acceptance Criteria. LRA Section B2.1.39 states that potentially defective coating surfaces identified during the course of an inspection are documented, their severity is evaluated, and corrective actions are taken to ensure there is no loss of intended functions between the inspections. The applicant stated that defective or deficient coating surfaces are prioritized as either needing repair during the same outage or as postponed to future outages. The applicant also stated that the evaluation covers degradations such as blistering, cracking, flaking, peeling, delamination, and rusting.

On February 8, 2012, the staff issued RAI B2.1.39-2, requesting the applicant to discuss any instances of degradation and repair of Service Level 1 coatings. In addition, the applicant was requested to provide information that demonstrates the effectiveness of corrective actions performed. In response by letter dated February 27, 2012, the applicant provided the following revised plant-specific evaluation criteria for the above-mentioned types of degradation:

- Blistering—Blistering of any size is a rejectable condition. The applicant stated that corrective actions will be taken when degraded coating is identified.
- Cracking—Cracking of any size is a rejectable condition. All cracks under 30 mils in width are documented and repaired in accordance with plant procedures. Cracks exceeding 30 mils in width and all cracks associated with delamination are evaluated under the site's CAP.
- Flaking/Peeling/Delamination—Flaking/peeling/delamination of any size is a rejectable condition. All flaking/peeling/delamination is documented and repaired in accordance with plant procedures. If the sum total of the repair area exceeds 25 percent of that item's total painted area or if each individual repair area exceeds 30 in^2, the condition is documented on a separate process record from.
- Rusting—Comparison with pictorial standards are performed by individuals trained in applicable referenced standards of ASTM D5498 on an as-needed basis as determined by the Nuclear Coatings Specialist. The source and extent of rusting is evaluated during the visual examination by the Nuclear Coatings Specialist.

The applicant stated that if no defects are found, a note of "Coating Intact, No defects" will be marked on the coatings condition assessment report form. In addition, if the portions of the coating cannot be inspected, the applicant stated that a note discussing why the area cannot be inspected will be reported in the coatings condition assessment report form.

The applicant stated that for coating surfaces determined to be suspect, defective, or deficient, destructive and nondestructive tests are performed by individuals trained in applicable referenced standards of ASTM D5498 on an as-needed basis, as determined by the Nuclear Coatings Specialist.

The staff reviewed the applicant's "acceptance criteria" program element against the criteria in SRP-LR Section A.1.2.3.6, which state that the acceptance criteria of the program and their basis should be described. One objective of the program is to ensure that the design-basis accident analysis limits with regard to debris loading from failed coatings will not be exceeded for the emergency core cooling system (ECCS) suction strainers.

The staff noted that the applicant uses industry standards to perform coating assessments. The staff finds the applicant's "acceptance criteria" program element to be adequate because the applicant appropriately identified defective or deficient coatings in accordance with ASTM D5163, and degraded coatings will be documented and summarized.

Based on the review of the application, the staff confirmed 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.

<u>Operating Experience</u>. LRA Section B2.1.39 summarizes operating experience related to the Protective Coating Monitoring and Maintenance Program. The applicant stated that STP implements controls for the procurement, application, and maintenance of Service Level 1 protective coatings used inside containment in a manner that is consistent with the licensing basis and regulatory requirements applicable to STP. It was further indicated that the requirements of 10 CFR Part 50, Appendix B, are implemented through specification of appropriate technical and quality requirements for the Service Level 1 Coatings Program.

The staff reviewed this information against the acceptance criteria in SRP-LR Section A.1.2.3.10, which state that the operating experience of AMPs, including past corrective actions resulting in program enhancements or additional programs, should be considered.

The staff noted that the LRA "operating experience" program element gives a general overview of the program and does not provide specific instances of degradation and its associated repair or other corrective actions performed. During its review, the staff determined the need for additional information to complete its review. In RAI B2.39-2, dated February 8, 2012, the staff asked the applicant to provide any instances of degradation and repair of Service Level 1 coatings. In addition, the staff asked the applicant to provide information that demonstrates the effectiveness of corrective actions performed.

In its response dated February 27, 2012, the applicant provided a revised "operating experience" program element. The applicant stated that it conducts condition assessments of Service Level 1 coatings inside containment during every refueling outage. Furthermore, the applicant stated that the types of operating experience for Service Level 1 coatings at STP include mechanical damage, minor isolated cracking measuring less than 30 mils in width, and minor surface rusting. The applicant also indicated that peeling, blistering, and delamination of Service Level 1 coatings that have the potential to block sumps and strainers have not been reported.

In particular, the applicant stated that, in November 2009, surface corrosion on a hanger support was identified in Unit 1 during the coatings condition assessment walkdown. The coatings degradation was characterized as minor surface rust due to condensation. Repairs to degraded coatings were made in accordance with the safety-related coatings specification.

The applicant also stated that, in April 2000, minor surface corrosion was identified on the Unit 2 liner plate at the interface of the liner plate and concrete basement through the condition reporting process. The degradation was characterized as minor rusting, and repairs were made in accordance with the safety-related coatings specification.

The staff finds the applicant's response acceptable because the applicant performs visual inspections every refueling outage in accordance with ASTM D5163. In addition, the applicant appropriately identified aging degradation in a timely manner and performed corrective actions. The staff's concern described in RAI B2.1.39-2 is resolved.

Based on its review of the application and review of the applicant's response to RAI B2.1.39-2, the staff finds that the applicant appropriately evaluated plant-specific and industry operating experience, and implementation of the program has resulted in the applicant taking corrective actions. In addition, the staff finds that the "operating experience" program element satisfies the criteria in SRP-LR Section A.1.2.3.10.

UFSAR Supplement. In a letter dated February 27, 2012, the applicant amended the UFSAR supplement. LRA Section A1.39 provides the UFSAR supplement for the Protective Coating Monitoring and Maintenance Program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the applicant committed (Commitment No. 40) to ongoing implementation of the existing Protective Coating Monitoring and Maintenance Program for managing aging of applicable components during the period of extended operation.

The staff finds that the information in the UFSAR supplement, as amended, is an adequate summary description of the program.

Conclusion. On the basis of the technical review of the applicant's Protective Coating Monitoring and Maintenance 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)(2). 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 Managing Loss of Coating Integrity for Internal Coatings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

Summary of Technical Information in the Application. After the LRA was submitted, based on reviews of recent industry operating experience and several LRAs, the staff identified an issue concerning loss of coating integrity of internal coatings of in-scope piping, piping components, heat exchangers, and tanks. By letter dated March 6, 2014, the staff issued RAI 3.0.3-2 requesting that the applicant address how loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage will be managed if coatings have been installed on the internal surfaces of in-scope components (i.e., piping, piping subcomponents, heat exchangers, and tanks). The staff issued LR-ISG-2013-01, "Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," on November 14, 2014. LR-ISG-2013-01 included a new GALL

Report AMP, XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks,” to address loss of coating integrity of internal coatings of in-scope piping, piping components, heat exchangers, and tanks.

Staff Evaluation. In RAI 3.0.3-2, the staff requested that, for coatings installed on the internal surfaces of in-scope components (i.e., piping, piping components, heat exchangers, tanks), the applicant state the following: the inspection method; parameters to be inspected; when inspections will commence and the frequency of subsequent inspections; the extent of inspections and the basis for the extent of inspections not performed at 100 percent; the training and qualification of individuals involved in coating inspections; how trending of coating degradation will be conducted; acceptance criteria; and corrective actions for coatings that do not meet acceptance criteria. The staff also requested that the applicant identify the programs that will be augmented to address the above activities. The staff’s evaluation of the eight areas addressed in the applicant’s response and changes to its AMPs and UFSAR supplements follows.

Inspection Method. In its response dated June 3, 2014, the applicant stated that visual inspections will be conducted in order to detect coating “deterioration, degradation, and erosion.” The applicant also stated that it will conduct low-voltage holiday testing in accordance with ASTM D5162, “Standard Practice for Discontinuity (Holiday) Testing of Nonconductive Protective Coating on Metallic Substrates;” dry film thickness measurements in accordance with ASTM D7091, “Standard Practice for Nondestructive Measurement of Dry Film Thickness of Nonmagnetic Coatings Applied to Ferrous Metals and Nonmagnetic, Nonconductive Coatings Applied to Non-Ferrous Metals,” and Steel Structures Painting Council (SSPC) PA-2, “Procedure for Determining Conformance to Dry Coating Thickness Requirements;” and pull-off adhesion testing in accordance with ASTM D4541, “Standard Test Method for Pull-Off Strength of Coatings Using Portable Adhesion Testers.”

The staff noted that:

- ASTM D5162-08 includes requirements for selection of the appropriate test device (e.g., high voltage, low voltage, wet-sponge), surface preparation, actions to be taken if a discontinuity is detected, verifying operation of the device, and verifying device calibration. The standard states that the device should be moved over the surface at a moderate rate with a double pass over each area.
- ASTM D7091-13 references SSPC PA-2 for determining the sample size to be inspected. The standard describes the various types of available gages and limitations on their use. The standard also states the frequency and methods for verifying the accuracy of a gage, calibration recommendations, adjustments to improve accuracy, and reporting requirements.
- SSPC PA-2, January 2015, includes requirements for equipment calibration, coating thickness tolerance when none is provided by the manufacturer, and reporting requirements. The sample size for SSPC PA-2 is: (a) three measurements for each spot measurement with five spot measurements being conducted for every 100 ft^2 of coated surface; (b) in coated surfaces greater than 300 ft^2 up to 1,000 ft^2, three 100 ft^2 areas are inspected; and (c) for coated surfaces exceeding 1,000 ft^2, a 100 ft^2 area is measured for each 1,000 ft^2. The specification includes measurement expansion criteria if out-of-specification measurements are detected.

The staff also noted that ASTM D4541-09 is endorsed for use in adhesion testing in RG 1.54.

The applicant did not specify the specific year or edition of the above-referenced standards. By letter dated October 5, 2015, the staff issued RAI 3.0.3-2c requesting that the applicant state the year or edition of all referenced standards.

In its response dated November 12, 2015, the applicant provided the editions of the referenced standards as noted above. The applicant also revised LRA Sections B2.1.9 (Open-Cycle Cooling Water System Program), B2.1.13 (Fire Water System Program), and B2.1.22 (Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program) to cite the specific editions.

The staff finds the applicant's response acceptable because: (a) conducting visual inspections of coating is consistent with AMP XI.M42; (b) the staff has endorsed the use of ASTM D4541 for adhesion testing in RG 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants;" and (c) the use of D5162, D7091, and SSPC PA-2 are acceptable because they are industry consensus documents being used for the purposes for which they were developed. The staff's concern described in RAI 3.0.3-2c is resolved.

Parameters To Be Inspected. In its response dated June 3, 2014, the applicant stated that coatings will be inspected for blistering, cracking, peeling, delamination, physical damage, and erosion.

The staff noted that the applicant did not list flaking and rusting as applicable parameters to be monitored. By letter dated May 27, 2015, the staff issued RAI 3.0.3-2a Part (c) requesting that the applicant state the basis for not inspecting for flaking and rusting.

In its response dated June 11, 2015, the applicant stated that coatings will be inspected for flaking and rusting.

The staff finds the applicant's response acceptable because the parameters to be inspected are consistent with those recommended in AMP XI.M42. The staff's concern described in RAI 3.0.3-2a Part (c) is resolved.

Commencement of Inspections and Frequency of Subsequent Inspections. In its response dated June 3, 2014, the applicant stated that the ECW pump internals and discharge piping reducer internal coatings are inspected every 10 years (nominally) during refurbishment. All other coatings are inspected every 6 years. All of these coatings are tested every 6 years after being in service for 12 years. The applicant also stated that baseline inspections (as recommended by AMP XI.M42 in the 10-year period prior to the period of extended operation) will not be conducted because all coatings are currently being inspected.

The staff noted that AMP XI.M42 recommends that inspections be conducted every 4 years if degraded coatings are detected during prior inspections. The response did not state the basis for conducting inspections every 6 years regardless of the results of prior inspections or the basis for inspecting the ECW pumps every 10 years. By letter dated May 27, 2015, the staff issued RAI 3.0.3-2a Part (a) requesting that the applicant state the basis for not conducting a baseline inspection in the 10-year period prior to the period of extended operation and for the subsequent 6-year and 10-year inspection intervals.

In its response dated June 11, 2015, the applicant stated that the implementation schedule portion of Commitment Nos. 4 (Open-Cycle Cooling Water System Program), 8 (Fire Water System Program), and 17 (Inspection of Internal Surfaces in Miscellaneous Piping and Ducting

Components Program) demonstrate that coating inspections will be conducted prior to the period of extended operation.

The staff finds the applicant's response in regard to baseline inspections acceptable because each of the programs include commitments to ensure that coating inspections will occur prior to the period of extended operation.

In its response dated June 11, 2015, to RAI B2.1.13-5, the applicant stated that:

> When visual inspections detect blistering, cracking, flaking, peeling, delamination, rusting and physical damage the degraded coating, under the guidance of the Nuclear Coating Specialist (NCS), is removed to sound base material and new coating applied. The as-found degraded condition is documented in the corrective action program for trending. Since the degraded coating has been removed and replaced with new coating the inspection interval is not changed. Review of STP's existing coating inspection program operating history demonstrates that the remediation of degraded coating conditions prior to returning the coating back in service is effective in managing the coating performance from one inspection to the next, with no change in inspection interval.

The staff lacked sufficient information to conclude that a 6-year or 10-year inspection interval was adequate. By letter dated October 5, 2015, the staff issued RAI B2.1.13-5a, requesting that the applicant state the basis for how the extent of coatings (other than those for the fire water storage tanks) that could be experiencing similar degradation to the coating areas that were repaired will be determined in a reasonable time frame.

The staff noted that in a letter dated March 29, 2015, the applicant stated:

> The ECW pump casings, diffuser, flanges, and discharge elbows are coated with Belzona to minimize loss of pump performance from flow erosion of the internal pump components. The Open-Cycle Cooling Water System program manages the ECW pumps and discharge piping reducers that are inspected during pump disassembly for refurbishment. ECW pump inspections have found the coatings intact with some coating discoloration on the pump columns. Blistering of the coatings has been found on the pump diffuser, flanges, and discharge elbow that are two-phase aluminum bronze alloy castings. The blistering is caused by buildup of corrosion products under the coating. Loss of material due to flow erosion has not been observed. Areas of blistering are cleaned and recoated.

The staff noted that in a letter dated May 10, 2012, the applicant stated:

> The coated ECW pumps are upstream of self-cleaning strainers. The self-cleaning strainers are designed to prevent material larger than 1/16" from entering the component cooling water heat exchangers. The self-cleaning strainer mesh size is smaller than the heat exchanger tubes and serves to protect the heat exchangers from particles greater than 1/16". The coating is inspected during pump disassembly. ECW pump disassembly is scheduled as a refurbishment activity and controlled by the Major Pump and Motor Maintenance Plan. This maintenance plan has a nominal 10 year refurbishment periodicity.

In its response dated November 12, 2015, the applicant stated the following:

- It has six trains of essential cooling water and one train is inspected every 6 years. The coatings installed on the essential chiller water box covers, standby diesel generator (SDG) jacket water coolers, SDG lube oil coolers, and SDG intercooler water box and interconnecting piping are all the same.
- The coating re-inspection interval for the Fire Water System Program for internal coatings on components other than the fire water storage tanks has been revised to 4 years. After three consecutive inspections that reveal no change in the coating condition, the inspection interval will be restored to 6 years.
- The coating re-inspection interval for the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program has been revised to 4 years. After three consecutive inspections that reveal no change in the coating condition, the inspection interval will be restored to 6 years.
- The self-cleaning strainers downstream of the essential cooling water pumps have a high strainer differential pressure alarm in the control room and plant operators observe the performance of the strainers while on watch tours. A strainer internal overhaul is conducted every 3 years. This overhaul ensures proper operation of the strainer.

LRA Sections A1.9, A1.13, and A1.22 were revised to state that coatings not meeting acceptance criteria are removed to sound metal and replaced.

The staff finds the applicant's response and proposed inspection interval acceptable based on the following:

- For the internal coatings on ECW boxes and coolers, degraded coatings are removed to sound metal and replaced and one of the six trains is inspected every year. As a result, regardless of whether degraded coatings are encountered, one-sixth of the coatings is inspected every year. Although only two-thirds of the components will be inspected every 4 years, the annual inspection of coatings ensures that adequate information in regard to the condition of coatings is available. In addition, plant-specific operating experience to date has revealed that repairing degraded coatings and conducting the inspections on this interval has been effective.
- The staff noted that LRA Table 3.3.2-4 states that the ECW pumps are constructed of aluminum bronze and the strainers are carbon steel lined with copper nickel cladding. Although the internal coatings on the ECW pumps will be conducted on a nominal 10-year frequency, the downstream strainer prevents potential loose coating materials from affecting the intended function of downstream components. The strainers are considered an adequate barrier because the internals are periodically inspected and clogging of the strainers would be detected in the control room by a plant alarm. Loss of material sufficient to cause through-wall corrosion of these components is not anticipated based on the periodic internal inspections and because the aluminum bronze and copper nickel components are not susceptible to loss of material due to general corrosion in the ECW environment.
- The coatings being managed for loss of coating integrity by the Fire Water System and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components programs will be inspected every 4 years. The provision to restore the inspection

interval to 6 years when three consecutive inspections reveal no change in the coating condition is consistent with AMP XI.M42.

- In regard to fire water storage tank inspection intervals, see the staff's evaluation of the response to RAI 3.0.3-2b Part (a), below.

Extent of Inspections. In its response dated June 3, 2014, the applicant stated 100 percent of the internal surfaces of coated components will be inspected and the sample size for low-voltage holiday testing, dry film thickness, and adhesion testing will be conducted in accordance with ASTM D5162, ASTM D7091 and SSPC PA-2, and ASTM D4541, respectively.

The staff finds the applicant's response acceptable because: (a) 100 percent coverage of the internal surfaces of coated components for visual inspections is consistent with AMP XI.M42; (b) the testing requirements of ASTM D4541 are endorsed in RG 1.54; and (c) the coverage for holiday testing and dry film thickness testing in ASTM D5162, ASTM D7091 and SSPC PA-2, (see staff's evaluation above) can be sufficient to detect degraded coatings.

Training and Qualifications. In its response dated June 3, 2014, the applicant stated that, "[c]oating inspections and tests are performed by a qualified Nuclear Coating Specialist (NCS) as defined by ASTM D7108 [Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist] or by Coatings Surveillance Personnel (CSP) under the technical direction of the NCS."

The staff noted that AMP XI.M42 recommends that inspection personnel be qualified in accordance with ASTM standards endorsed in RG 1.54. The applicant's response did not state the minimum qualification requirements of inspectors working under the direction of a Nuclear Coatings Specialist. By letter dated May 27, 2015, the staff issued RAI 3.0.3-2a Part (b) requesting that the applicant state the minimum qualification requirements for inspectors working under the direction of a Nuclear Coatings Specialist.

In its response dated June 11, 2015, the applicant stated that Nuclear Coatings Specialists qualified in accordance with ASTM D7108 will be used to perform coating inspections and tests. Coating Surveillance Personnel will not be used for these inspections and tests. The staff noted that ASTM D7108 is endorsed in RG 1.54 as a means to qualify coatings specialists. The staff finds the applicant's response acceptable because qualifying individuals who conduct coating inspections and tests in accordance with a standard referenced in RG 1.54 is consistent with AMP XI.M42. The staff's concern described in RAI 3.0.3-2a Part (b) is resolved.

Trending. In its response dated June 3, 2014, the applicant stated that it will conduct a pre-inspection review of previous inspection results, which includes repair activities. A coatings specialist will prepare a post-inspection report that includes a list and the location of all areas of deterioration, including photographic documentation indexed to inspections where possible.

The staff noted that in its response to RAI 3.0.3-2a Part (d) the applicant stated that, "[w]hen visual inspections detect any blistering, cracking, erosion, cavitation erosion, flaking, peeling, delamination, rusting and physical damage, the coating is considered degraded. Degraded coatings are removed to sound material and replaced with new coating." As a result, the staff concludes the recommendation in the "monitoring and trending" program element of AMP XI.M42, which states, "a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where repair can be postponed to the next refueling outage," is not applicable to this applicant because there will be no postponing nor prioritizing of repairs.

Acceptance Criteria and Corrective Actions. In its response dated June 3, 2014, the applicant stated, "[t]he acceptance criteria for coatings are that no erosion, corrosion, cavitation erosion, flaking or peeling of the coatings is observed. Coatings not meeting these criteria are considered degraded and a condition report is initiated to document and resolve the concern." The applicant also stated that coatings not meeting acceptance criteria are repaired as needed.

The staff noted that AMP XI.M42 recommends that indications of peeling and delamination are not acceptable. It also recommends that the other indications of degradation be evaluated by a Nuclear Coatings Specialist. It further recommends that coatings that do not meet acceptance criteria are repaired, replaced, or removed. Based on the RAI response statements provided in the June 3, 2014 letter, it is unclear to the staff what conditions of degraded coatings will result in repair, replacement, or removal of the degraded coating conditions. By letter dated May 27, 2015, the staff issued RAI 3.0.3-2a Part (d) requesting that the applicant state what indications of coating degradation will be found unacceptable and those that will be evaluated by a Nuclear Coatings Specialist for acceptability. The staff also asked the applicant to state what indications of coating degradation will be repaired, replaced, or removed prior to returning a component to service.

In its response dated June 11, 2015, the applicant stated that:

> When visual inspections detect any blistering, cracking, erosion, cavitation erosion, flaking, peeling, delamination, rusting and physical damage the coating is considered degraded. Degraded coatings are removed to sound material and replaced with new coating. The as-found degraded condition is documented in the corrective action program for trending. The NCS oversees the replacement of the degraded coatings assuring the extent of repaired or replaced coatings encompasses sound coating material. Review of STP's existing coating inspection program operating history demonstrates that the remediation of degraded coating conditions prior to returning the coating back in service is effective in managing the coating performance from one inspection to the next, with no change in inspection interval.

The staff finds the applicant's response acceptable in part because: the applicant's list of indications is consistent with the "acceptance criteria" program element of AMP XI.M42 and any indications that do not meet acceptance criteria will result in the coating being removed to sound material and replaced with new coating. The "corrective actions" program element of AMP XI.M42 states that, "[t]esting or examination is conducted to ensure that the extent of repaired or replaced coatings/linings encompasses sound coating/lining material." It is not clear to the staff how the Nuclear Coating Specialist's oversight will result in "assuring the extent of repaired or replaced coatings encompasses sound coating material." Although AMP XI.M42 does not recommend specific tests or exams for ensuring that repaired or replaced coatings encompasses sound coating material, the applicant did not state whether tests or examinations will be conducted prior to or during the replacement of the coatings. In addition, SRP-LR Table 3.0-1, as modified by LR-ISG-2013-01 states, "[f]or coated/lined surfaces determined to not meet the acceptance criteria, physical testing is performed where physically possible (i.e., sufficient room to conduct testing) in conjunction with repair or replacement of the coating/lining" By letter dated October 5, 2015, the staff issued RAI B2.1.13-5a Part (2) requesting that the applicant state whether: (a) testing and examination will be conducted to ensure that replaced coatings encompasses sound coating/lining material; and (b) the testing will include physical techniques in addition to visual examination.

In its response dated November 12, 2015, the applicant stated, “[r]epairs are overseen by a NACE certified coating specialist who utilizes visual and physical techniques to determine when sound coating material is achieved prior to repair. No post-repair testing is performed.”

The staff finds the applicant’s response acceptable because visual and physical testing will be conducted to ensure that repairs are installed on sound coating material as recommended by the “corrective action” program of AMP XI.M42, which states, “[t]esting or examination is conducted to ensure that the extent of repaired or replaced coatings/linings encompasses sound coating/lining material.”

The staff’s concern described in RAI B2.1.13-5a Part (2) is resolved.

The applicant revised LRA Sections B2.1.9, “Open-Cycle Cooling Water System Program,” B2.1.13, “Fire Water System Program,” and B2.1.22, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program,” to reflect the above responses. The staff noted that LRA Section B2.1.9 was revised to state, “[c]oating installed to mitigate corrosion of the essential chiller water box covers, SDG jacket water coolers, SDG lube oil coolers, SDG intercooler water boxes and interconnection piping are inspected and tested to assure coating integrity.” It was not clear to the staff whether internal coatings installed for purposes other than corrosion (e.g., prevention of erosion damage) will be inspected. By letter dated October 5, 2015, the staff issued RAI 3.0.3-2b Part (a) requesting that the applicant state the basis for limiting coating inspections in the Open-Cycle Cooling Water System Program to those locations where the coatings were installed to mitigate corrosion.

In its response dated November 12, 2015, the applicant revised LRA Sections A1.9, A1.13, A1.22, B2.1.9, B2.1.13, and B2.1.22 to state that 100 percent of internal coatings will be inspected. However, fire water storage tank internal coatings are inspected in accordance with NFPA-25 “Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems,” 2011 Edition.

The staff noted that NFPA-25 Section 9.2.6 requires that the internal surfaces of fire water storage tanks be inspected every 5 years. If signs of pitting, corrosion, spalling, or local or general failure of interior coating are detected, Section 9.2.7 requires followup testing, including adhesion testing, dry film thickness measurements, wet-sponge testing, and wall thickness measurements. The staff finds the applicant’s response acceptable because all nontank-related internal coatings will be inspected. The staff finds the citing of NFPA-25 for the inspection of internal coatings on fire water storage tanks acceptable because NFPA-25 is recommended by AMP XI.M27, “Fire Water System,” for the internal inspections of coated and noncoated fire water storage tanks. The staff’s concern described in RAI 3.0.3-2b Part (a) is resolved.

Based its review of the applicant’s changes to the Open-Cycle Cooling Water System Program, Fire Water System Program, and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program and the applicant’s responses to RAIs 3.0.3-2, 3.0.3-2a, 3.0.3-2b, 3.0.3-2c, B2.1.13-5, and B2.1.13-5a, the staff finds that program elements one through seven are consistent with the corresponding program elements of GALL Report AMP XI.M42.

<u>Operating Experience</u>. Given that LR-ISG-2013-01 was issued subsequent to the issuance of the LRA, no plant-specific operating experience was cited in the application. However, as documented in SER Section 3.0.3.2.6, during the audit, the staff reviewed operating experience associated with degradation of coatings in the ECW system. During its review, the staff found

no operating experience to indicate that the applicant's programs would not be effective in adequately managing aging effects during the period of extended operation.

UFSAR Supplement. LRA Sections A1.9, A1.13, and A1.22 provide the FSAR supplement for the Open-Cycle Cooling Water System, Fire Water System, and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components programs. SRP-LR Table 3.0-1, as modified by LR-ISG-2013-01 states, "[f]or coated/lined surfaces determined to not meet the acceptance criteria, physical testing is performed where physically possible (i.e., sufficient room to conduct testing) in conjunction with repair or replacement of the coating/lining." The staff reviewed these FSAR supplement descriptions of the programs against the recommended description for this type of program as described in SRP-LR Table 3.0-1, as modified by LR-ISG-2013-01, and noted that they did not include the above statement related to physical testing of coatings that do not meet acceptance criteria. The licensing basis for this program for the period of extended operation may not be adequate if the applicant does not incorporate this information in its FSAR supplement. By letter dated October 5, 2015, the staff issued RAI B2.1.13-6a requesting that the applicant state the basis for not including a statement related to physical testing of coatings that do not meet acceptance criteria in the licensing basis for these programs during the period of extended operation.

In its response dated November 12, 2015, the applicant revised LRA Sections A1.9, A1.13, A1.22, B2.1.9, B2.1.13, and B2.1.22 to state, "[p]hysical testing is performed where physically possible in conjunction with repair or replacement of coatings."

The staff finds the applicant's response acceptable because it is consistent with SRP-LR Table 3.0-1 as modified by LR-ISG-2013-01 and the "corrective action" program element. The staff's concern described in RAI B2.1.13-6a is resolved.

The staff also noted that the applicant committed (Commitment Nos. 4 and 8) to ongoing implementation of the existing Open-Cycle Cooling Water System and Fire Water System programs for managing aging of applicable components during the period of extended operation. The staff also noted that the applicant committed (Commitment No. 17) 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 finds that the information in the FSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its review of the applicant's changes to the Open-Cycle Cooling Water System Program, Fire Water System Program, and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, the staff determines that the programs, as modified, are consistent with GALL Report AMP XI.M42. The staff reviewed the enhancements to the cited programs and confirmed that their implementation through Commitment Nos. 4, 8, and 17 prior to the period of extended operation will make the AMPs adequate to manage the applicable aging effects. 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 FSAR 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 LRA Appendix A, "Final Safety Analysis Report Supplement," Section A1, "Summary Descriptions of Aging Management Programs," and LRA Appendix B, "Aging Management Programs," Section B1.3, "Quality Assurance Program and Administrative Controls," the applicant described the elements of corrective action, confirmation process, and administrative controls that are applied to both safety-related and nonsafety-related components. The STP QA Program is used, which includes the elements of corrective action, confirmation process, and administrative controls. Corrective actions, the confirmation process, and administrative controls are applied in accordance with the STP QA Program regardless of the safety classification of the components. LRA Appendix B, Section B1.3, states that the STP QA Program implements the requirements of 10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," and is consistent with 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 quality assurance 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 should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.
- Attribute No. 9—Administrative controls 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, QA Program 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 LRA Appendix B, Section B1.3, and the applicable implementing procedure, which describe how the existing STP QA Program includes the QA-related elements (corrective action, confirmation process, and administrative controls), which is consistent with the staff's guidance described in Branch Technical Position IQMB-1. The staff also reviewed a sample of the AMPs, as described in LRA Appendix B, and confirmed that the AMPs addressed the three QA elements, as described in the AMP basis documents. The staff also reviewed the applicable implementing procedure, which describes the approach to QA in more detail.

The staff determined that additional information would be required to complete its review. RAI 3.0.4-1, Part 2, dated September 21, 2011, states, in part, the following:

> During the review of the LRA and associated [CLB] documents, the staff determined that the applicant had received approval of an exemption from special treatment requirements (the exemption) in an August 3, 2001, NRC letter. For NRS or LSS SCs within the scope of license renewal and included in an aging management program, the staff requested applicant to indicate whether the exemption has precluded or impacted the application (including use of the 10 CFR Part 50, Appendix B quality assurance program) of elements 7 (corrective actions), 8 (confirmation process) or 9 (administrative controls), for NRS or LSS SCs.

The applicant responded by letter dated November 21, 2011, which states, in part, the following:

> The special treatment exemption of NRS and LSS components does not preclude or impact the application (including use of the 10 CFR Part 50, Appendix B quality assurance program) of elements 7 (corrective actions), 8 (confirmation process), or 9 (administrative controls). As stated in UFSAR section 13.7.3.3.6, "the Station's Corrective Action Program is used for safety-related (LSS and NRS as well as HSS [high safety significance] and MSS [medium safety significance] SSCs) applications. The Corrective Action Program complies with 10 CFR Part 50 Appendix B, and is described in the OQAP [Operations Quality Assurance Plan].

The staff reviewed the response to RAI 3.0.4-1, Part 2, and determined that the applicant would apply the 10 CFR Part 50, Appendix B QA elements (No. 7 – corrective actions, No. 8 – confirmation process, and No. 9 – administrative controls) to NRS or LSS SCs that are included in an AMP. The staff's concerns in RAI 3.0.4-1, Part 2, are resolved.

Based on the staff's evaluation, the descriptions of the AMPs and their associated quality attributes—provided in LRA Appendix A, Section A1, and LRA Appendix B, Section B1.3—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 of the descriptions and applicability of the AMPs and their associated quality attributes provided in LRA Appendix A, Section A1, and LRA Appendix B, Section B1.3, and the applicant's response to RAI 3.0.4-1, Part 2, the staff determines the QA attributes 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 for Aging Management Programs

3.0.5.1 Summary of Technical Information in the Application

LRA Section B1.4 describes the consideration of operating experience for AMPs. The LRA states that this information was obtained through the review of in-house operating experience in the CAP, self-assessments of programs, and program health reports. In addition, the LRA states that a review of industry operating experience focused primarily on information after 2005 because industry operating experience prior to 2005 is addressed in Revision 1 to the GALL Report. The LRA also states that plant-specific operating experience and applicable industry operating experience were obtained through a review of CAP records from August 1998 through April 2010 to ensure that there was no unique plant-specific operating experience beyond that provided in the GALL Report, and this review was augmented with information from program engineers. Further, some, but not all, of the program descriptions in LRA Appendix B indicate that future operating experience will be considered. For example, LRA Section B2.1.20 states that, "[a]s additional industry and plant-specific applicable operating experience becomes available, it will be evaluated and incorporated into the program through the STP condition reporting and operating experience programs." LRA Section B2.1.35 contains another example, as follows:

> As additional [i]ndustry and applicable plant-specific operating experience become available, the [operating experience] will be evaluated and appropriately incorporated into the program through the STP Corrective Action and Operating Experience Programs. This ongoing review of [operating experience] will continue throughout the period of extended operation, and the results will be maintained onsite. This process will confirm the effectiveness of this new license renewal aging management program by incorporating applicable [operating experience] and performing self assessments of the program.

3.0.5.2 Staff Evaluation

3.0.5.2.1 Overview

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. SRP-LR, Revision 2, Appendix A, describes 10 elements of an acceptable AMP. SRP-LR 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 AMPs should be discussed. Reviews of operating experience by the applicant in the future may identify areas where AMPs 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 AMPs or indicate a need to develop new AMPs. 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 functions 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 adequately managed so that the structure- and component-intended functions 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. However, there may be other relevant plant-specific operating experience at the plant or generic operating experience in the industry that is relevant to the AMP's program elements even though the operating experience 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 operating experience that results from the past implementation of its existing AMPs that are existing programs and the impact of relevant generic operating experience 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 below evaluation discusses the staff's review of the first attribute, which concerns the consideration of future operating experience and applies to both existing and new programs.

3.0.5.2.2 Consideration of Future Operating Experience

The staff reviewed LRA Sections B1.4, B2.1.1 through B2.1.37, and B3.1 through B3.3 to determine whether the applicant will implement adequate activities for the ongoing review of both plant-specific and industry operating experience to identify areas where the AMPs should be enhanced or new AMPs developed. The staff determined that, while these LRA sections describe how the applicant incorporated operating experience into its AMPs, they do not fully describe how the applicant will use future operating experience to ensure that the AMPs will remain effective for managing the effects of aging during the period of extended operation. The main focus of these LRA sections is on how the applicant evaluated operating experience available at the time the application was prepared to justify the adequacy of its proposed AMPs. Some of the program descriptions, particularly for new programs, contain statements indicating that future plant-specific and industry operating experience will be used to adjust the AMPs, as appropriate, but the details of this process are not described. For the majority of AMPs, it is not clear whether the applicant intends to monitor operating experience on an ongoing basis and to use it to ensure the continued effectiveness of the AMPs or to develop new AMPs, as necessary.

By letter dated May 24, 2011, the staff issued RAI B1.4-1 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. The staff requested the applicant to address the following items in the response:

- sources of plant-specific and industry operating experience information reviewed on an ongoing basis
- criteria for determining when operating experience concerns aging
- training of plant personnel for identifying aging-related issues
- evaluation of operating experience to determine its potential impact on plant aging management activities
- consideration of SCs, their materials, environments, aging effects, aging mechanisms, and AMPs in operating experience evaluations
- consideration of AMP inspection results
- records kept of operating experience evaluations
- process for the timely implementation of enhancements identified through operating experience evaluations
- administrative controls over operating experience review activities

By letter dated June 23, 2011, the applicant responded to RAI B1.4-1. The response states that the applicant maintains procedures for the feedback of operating information, including aging-related issues, pursuant to item I.C.5, "Procedures for Feedback of Operating Experience to Plant Staff," of NUREG-0737, "Clarification of TMI Action Plan Requirements," dated November 1980. The applicant stated that this process (i.e., the OEP) provides for the systematic evaluation of significant nuclear plant operating experiences and incorporation of lessons learned into appropriate plant practices, policies, programs, and procedures, with the objective of preventing similar issues. The process also provides for the sharing of lessons learned internally and with other utilities to promote industry-wide safety and reliability. The applicant also stated that the CAP complements the OEP to monitor aging-related issues. The applicant stated that the CAP implements the requirements of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," and provides a process to ensure that a broad range of issues or conditions can be documented and coded to enable trending for the purpose of addressing broader programmatic or process weaknesses. Under the CAP, conditions adverse to quality are identified, classified regarding significance, and reported to the appropriate level of management, and the cause of the condition is determined and subsequently corrected. Additionally, the applicant provided examples of plant-specific and industry operating experience that are monitored on an ongoing basis to identify potential aging issues. Regarding training, the applicant stated that AMP owners are selected based on educational background and experience. Engineering support personnel have been trained on the equipment reliability process, which includes aging-related inputs, and engineering personnel have also been trained on EPRI Report 1007933, "Aging Assessment Field Guide." The applicant also provided a revised UFSAR supplement to describe its OEP in a letter dated August 8, 2011.

The staff reviewed the applicant's response to RAI B1.4-1 and determined that it provides a general description of the processes used to evaluate operating experience on an ongoing basis; however, it does not provide specific information on how aging-related issues are addressed under these processes. In particular, the staff determined that additional information was necessary because the applicant did not adequately describe:

- the sources of operating experience reviewed
- prioritization and timely completion of operating experience evaluations
- information included in operating experience evaluations and whether these evaluations are auditable and retrievable
- monitoring of operating experience evaluation results
- how enhancements to the AMPs will be implemented
- how the effectiveness the OEP is ensured
- criteria for identifying and categorizing operating experience as related to aging
- training
- how plant-specific operating experience related to aging will be reported to the industry.

By letter dated February 8, 2012, the staff issued RAI B1.4-2 requesting that the applicant address these issues for both the CAP and the OEP.

By letter dated February 27, 2012, the applicant responded to RAI B1.4-2 with additional information on the CAP and OEP as they relate to the aging management process. The applicant stated that various sources are reviewed for applicable operating experience, including documents from the Institute for Nuclear Power Operations (INPO), the NRC, and NEI. The applicant also described the process and timetable for which internal and external operating experience is processed and evaluated through the OEP and CAP. The applicant further described the criteria for screening applicable operating experience documents for further evaluation. The applicant also stated that plant-specific operating experience is captured through the generation of condition reports in the CAP. The applicant described how the CAP's event codes that capture aging-related degradation are used to determine degraded conditions, and described the corrective actions initiated by the CAP that include enhancements to existing AMPs or development of new AMPs. Procedures for communicating operating experience to the industry and details on the training on aging issues for personnel involved with these processes were also described.

Subsequent to the receipt of the applicant's response to RAI B1.4-2, the staff issued LR-ISG-2011-05, "Ongoing Review of Operating Experience," on March 16, 2012, which presented the staff's overall review of an applicant's consideration of operating experience for AMPs; this LR-ISG was factored into the staff's review of the applicant's response to RAI B1.4-2.

The staff reviewed the applicant's response to RAI B1.4-2 and found that the applicant did not provide an adequate description of the "event codes" used in the CAP, nor details concerning the periodicity and results from the applicant's training "needs analysis" described in its response. The applicant also did not provide an adequate description in its UFSAR supplement of how it reviews operating experience related to aging degradation.

By letter dated June 14, 2012, the staff issued RAI B1.4-3 requesting that the applicant provide specific details and definitions of the "event codes" in the CAP; state how the results of the training "needs analysis" will be evaluated and considered, including the periodicity of the training; and provide a revision to the UFSAR supplement showing a more detailed description of how operating experience will be reviewed on an ongoing basis.

By letter dated June 14, 2012, the applicant responded to RAI B1.4-3, and provided specific event codes in its CAP that currently capture aging-related degradation or equipment failure and described how these codes will be used. The response also describes additional details on the training requirements and needs analysis for personnel involved with operating experience. The applicant also provided a more detailed UFSAR supplement that describes how the OEP and CAP review aging-related operating experience.

The staff evaluated the details of the applicant's descriptions of the ongoing operating experience review activities provided in response to RAIs B1.4-1, B1.4-2, and B1.4-3. The staff evaluated the adequacy of these activities with respect to the following nine recommendations in LR-ISG-2011-05:

(1) consideration of operating experience in the 10 CFR Part 50, Appendix B, program
(2) sources of operating experience
(3) consideration of all incoming plant-specific and industry operating experience
(4) identification of operating experience related to aging
(5) information considered in operating experience evaluations
(6) consideration of AMP implementation results as operating experience
(7) training
(8) reporting operating experience to the industry
(9) implementation schedule

The staff's evaluation of each area follows.

3.0.5.2.3 LR-ISG-2011-05 Areas of Further Review

<u>Consideration of Operating Experience in 10 CFR Part 50, Appendix B, Program</u>. The staff evaluated how the applicant's 10 CFR Part 50, Appendix B, Program will consider operating experience on aging-related degradation and aging management. LRA Section B1.3, "Quality Assurance Program and Administrative Controls," states that the QA Program implements the requirements of 10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Processing Plants," and is applicable to all safety-related and nonsafety-related SSCs that are subject to aging management. The staff finds it acceptable that the applicant's QA Program scope considers operating experience related to aging degradation for both safety-related and nonsafety-related SCs subject to an AMR in accordance with 10 CFR 54.21(a)(1). By expanding the scope, the QA Program can incorporate operating experience related to aging degradation and aging management that constitutes information on the SCs identified in the IPA; the materials, environments, aging effects, and aging mechanisms; the AMPs credited for managing the effects of aging; and the activities, criteria, and evaluations integral to the elements of the AMPs.

<u>Sources of Operating Experience</u>. The staff evaluated the sources of operating experience reviewed by the applicant. The applicant's response dated June 23, 2011, states that the CAP provides a process that captures a broad range of issues or conditions that are monitored and trended to address broader programmatic or process weaknesses. The applicant further stated that the CAP identifies and classifies conditions adverse to quality, investigates the sources, and initiates corrective actions. Examples of plant-specific operating experience sources are also listed, such as input from plant-specific LERs and adverse results of inspections from

AMPs. Therefore, the staff finds acceptable the sources of plant-specific operating experience because procedures direct adverse conditions to be processed through the CAP. The response dated June 23, 2011, also provides examples of industry operating experience source documents that are screened under the OEP for applicability. This includes INPO Operating Experience Event Reports, NRC generic communications, and vendor recommendations. In its response dated February 27, 2012, the applicant committed to add NRC license renewal interim staff guidance and revisions to the GALL Report to the source documents reviewed by December 31, 2014. By letter dated December 6, 2012, the commitment date was revised to "no later than the date the renewed operating licenses are issued." The staff also finds acceptable the sources of industry operating experience because the OEP prescribes review of operating experience from what the staff considers to be the primary providers of industry operating experience information (i.e., NRC, other nuclear power plants through INPO, and vendors). The NRC previously endorsed the use of the INPO program as the mechanism for the central collection and screening of all events from both U.S. and foreign nuclear plants in GL 82-04, "Use of INPO SEE-IN Program," dated March 9, 1982.

<u>Consideration of All Incoming Plant-Specific and Industry Operating Experience</u>. The staff evaluated the applicant's activities for screening all incoming plant-specific and industry operating experience to determine whether it might involve aging-related degradation or impacts to aging management activities. The applicant's response dated June 23, 2011, states that the CAP complements the OEP to monitor age-related issues. The applicant further states that the source documents are monitored on an ongoing basis to identify potential aging issues and placed in the CAP. The applicant's response dated, February 27, 2012, states that aging effects, aging mechanisms, and AMPs are considered when assessing applicability of an operating experience source document for further evaluation. The applicant further stated that "event codes" are used in the CAP to identify aging-related equipment failures or degradation. The staff finds the applicant's use of the CAP and the OEP to screen operating experience acceptable because both programs would capture plant-specific and industry operating experience related to aging.

<u>Identification of Operating Experience Related to Aging</u>. The staff evaluated the applicant's identification of plant-specific operating experience as related to aging in the CAP. The applicant's response dated June 14, 2012, states that event codes are used in the CAP to capture equipment failures or degradation that is aging-related. The response lists the event codes currently used by the CAP and the descriptions of the degradation conditions, such as blocked/restricted, corroded/deteriorated, deformed/bent, and ruptured/cracked/fractured. The applicant further stated that it will also review the need for additional codes, including evaluating the codes being developed for the INPO Consolidated Event System. The response also states these event codes will also be used to identify plant-specific operating experience that will be reported to the industry. The staff finds the applicant's process for identifying operating experience acceptable as related to aging because all operating experience items submitted into the CAP and to INPO operating experience will be reviewed and identified for potential aging issues.

<u>Information Considered in Operating Experience Evaluations</u>. The staff evaluated the information the applicant will consider in the operating experience evaluations. The applicant's response dated February 27, 2012, states that the OEP will be revised to include "aging effects" to the list of characteristics for determining applicability of an operating experience document that may require further evaluation. Evaluations should consider the following characteristics: SSCs, materials, environments, aging effects, aging mechanisms, and AMPs. The applicant further stated that applicable operating experience documents are then evaluated for the impact

to plant programs and procedures. The response also states that implementing actions and corrective actions that are initiated from the evaluations are processed through the CAP. The applicant stated that these corrective actions may include enhancements to existing AMPs or the development of new AMPs. The staff finds the information that will be considered in the applicant's operating experience reviews acceptable because the reviews will identify potential aging issues and consider the fundamental components of an AMR; namely, the potentially affected plant SSCs, materials, environments, aging effects, aging mechanisms, and AMPs. Consideration of this information in the operating experience reviews will help to address all potential impacts to aging management activities.

Consideration of AMP Implementation Results as Operating Experience. The staff evaluated the applicant's consideration of AMP implementation results as operating experience. The applicant's response dated February 27, 2012, states that results of inspections, tests, and analyses conducted through implementation of each AMP are considered to be operating experience. The applicant stated that the results are screened through acceptance criteria and, if met, are retained for future use and evaluation. The applicant further stated that these results are used to determine, for example, if the frequency should be adjusted for future inspections, if new inspections should be established, or if the inspection scope should be adjusted or expanded. The applicant also stated that if results do not meet the applicable acceptance criteria, then corrective actions are initiated in accordance with the QA Program. The applicant stated that corrective actions could include enhancements to AMPs or the development of new AMPs. The staff finds the applicant's response acceptable because data collected by the AMPs will be reviewed and revisions to the programs will be implemented as necessary, which will further help to ensure the program is effective.

Training. The staff evaluated the training of plant personnel responsible for implementing the AMPs and those personnel who may submit, screen, assign, evaluate, or otherwise process plant-specific and industry operating experience. The applicant's response dated February 27, 2012, states that a training "needs analysis" on aging-related effects will be performed for plant personnel who screen, assign, evaluate, and submit internal and external operating experience. The applicant stated that the "needs analysis" will consider whether personnel are responsible for the following:

- appropriately identifying when operating experience has the potential to involve aging-related degradation
- understanding the purpose and scope of the AMPs, how these programs manage the effects of aging applicable to the plant, and which aging degradation is likely to occur
- identifying the difference between an evaluation for operability and an evaluation for aging-related degradation

The applicant's response dated June 14, 2012, also states the analysis for training on aging-related operating experience will identify the key individuals, which includes AMP owners. The applicant further stated that the "needs analysis" will include training frequency, task elements, knowledge and skills required for task performance, and conditions and standards for task performance. The applicant also stated that the analysis will include a requirement for individuals to complete the training before performing tasks (to account for personnel turnover), and will determine a periodicity for the training. The staff finds the applicant's training of plant personnel acceptable because the primary personnel responsible for screening, assigning, evaluating, and submitting operating experience issues will receive training on aging-related topics. The staff also finds the applicant's training acceptable because it will be periodically updated and will be required for new personnel.

Reporting Operating Experience to the Industry. The staff evaluated the applicant's plans for reporting operating experience to the industry. The applicant's response dated February 27, 2012, states that the OEP provides the guidelines for reporting plant-specific operating experience related to aging management and aging-related degradation to the INPO Nuclear Network. As previously discussed, the applicant uses event codes in the CAP to identify aging-related degradation effects. The applicant stated that these codes will be used to identify the plant-specific operating conditions that will be reported to the industry. The applicant further stated that the OEP procedure will be enhanced to provide the specific criteria for reporting internal operating experience related to aging degradation. Also as previously discussed, the applicant will require training on aging-related effects for personnel who screen, assign, evaluate, implement, and submit plant-specific operating experience. The staff finds the applicant's guidelines for reporting internal operating experience to the industry acceptable because they address aging issues and because individuals identifying and reporting noteworthy operating experience will have been trained on aging topics. This reporting of operating experience to the industry is consistent with the NRC's endorsement of the INPO program in GL 82-04.

Implementation Schedule. The staff evaluated the implementation schedule for the applicant's operating experience review activities. By letter dated February 27, 2012, as revised by letter dated June 14, 2012, the applicant identified several enhancements to the existing operating experience review activities. These enhancements involve the following:

- reviewing LR-ISG documents and revisions to the GALL Report as sources of operating experience
- including "aging effects" as a characteristic used to determining applicability of an operating experience document for further evaluation
- considering SSCs, materials, environments, aging effects, aging mechanisms, and AMPs in screened-in operating experience evaluations
- reviewing the CAP event codes to ensure identification of aging-related degradation effects
- completing a training "needs analysis" for plant personnel who process operating experience information for aging-related effects
- providing criteria for reporting plant-specific operating experience on aging-related degradation

By letter dated December 6, 2012, the applicant stated that these enhancements will be implemented no later than the date when the renewed operating licenses are issued. Also, by letter dated August 18, 2011, as revised by letters dated February 27, 2012, and June 14, 2012, the applicant amended the UFSAR supplement to include a summary description of the operating experience review activities and the associated enhancements described above. As discussed below in SER Section 3.0.5.3, the staff finds that this summary description is sufficiently comprehensive to describe the applicant's programmatic activities for evaluating operating experience. On issuance of the renewed licenses in accordance with 10 CFR 54.3(c), this summary description will be incorporated into the plant's CLB, and, at that time, the applicant will be committed to conduct its operating experience review activities accordingly.

Therefore, the staff finds the implementation schedule acceptable because the applicant will implement the enhanced operating experience review activities on an ongoing basis throughout the terms of the renewed operating licenses.

3.0.5.2.4 Summary

Based on its review of the information provided by the applicant in the LRA; the applicant's responses to RAIs B1.4-1, B1.4-2, and B1.4-3; and with consideration of the guidance contained in LR-ISG-2011-05, the staff determines that the applicant's programmatic activities for the ongoing review of operating experience are acceptable (a) for the systematic review of plant-specific and industry operating experience to ensure that the license renewal AMPs are—and will continue to be—effective in managing the aging effects for which they are credited and (b) for the enhancement to or development of new AMPs when the evaluation of operating experience determines that the effects of aging may not be adequately managed. The staff's concerns described in RAIs B1.4-1, B1.4-2, and B1.4-3 are resolved.

3.0.5.3 UFSAR Supplement

The staff reviewed the UFSAR supplement in LRA Appendix A to determine whether it provides an adequate summary description of the programmatic activities for the ongoing review of operating experience. Because the staff found no such description, it also requested in RAI B1.4-1 that the applicant provide a summary description of these activities for the UFSAR supplement, as required by 10 CFR 54.21(d).

By letter dated June 23, 2011, the applicant responded to RAI B1.4-1. The response states that operating experience is only one element of the AMPs described in LRA Appendix A, and that the applicant did not intend to amend the UFSAR supplement. Instead, the applicant revised Commitment No. 29 to indicate that it would perform future reviews of plant-specific and industry operating experience. The applicant also indicated that its commitment management and administration process is appropriate for managing commitments because it is consistent with the guidance in NEI 99-04, "Guidelines for Managing NRC Commitment Changes," dated July 1999.

Since the applicant did not provide a summary description for the UFSAR supplement, on August 8, 2011, the staff held a teleconference with the applicant to discuss the need to provide one for the staff's review. By letter dated August 18, 2011, the applicant added to its response to RAI B1.4-1 by providing this entry to LRA Section A1:

> Operating experience is applied to all aging management programs discussed in Sections A1 and A2. Plant-specific and industry operating experience is continuously reviewed to confirm the effectiveness of aging management programs and is [used], as necessary, to enhance each aging management program or to develop new aging management programs in order to adequately manage the effects of aging so that the intended functions of structures and components are met.

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. These sections recommend that 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 because it only provides a general description of the processes used to evaluate operating experience on an ongoing basis. By letter dated February 8, 2012, the staff issued RAI A1-1 to request specific information on how aging-related issues are addressed under the processes used to evaluate operating experience on an ongoing basis.

By letter dated February 27, 2012, the applicant responded to RAI A1-1 with a revised UFSAR supplement that provides more details on how the processes and procedures for the review of operating experience address aging issues. Subsequent to the receipt of the applicant's response, the staff also issued LR-ISG-2011-05 on March 16, 2012. The staff reviewed the revised summary description and determined that that it did not sufficiently address the key areas for consideration when compared to the guidance in LR-ISG-2011-05. Therefore, by letter dated June 14, 2012, the staff issued RAI B1.4-3 to request a more detailed summary description of how operating experience will be reviewed on an ongoing basis to address aging-related issues that, at a minimum, captures a level of detail consistent with the guidance described in LR-ISG-2011-05.

By letter dated June 14, 2012, the applicant responded to RAI B1.4-3 with a revised summary description of the ongoing operating experience review activities. The staff reviewed the applicant's response and found that, in addition to providing a revised summary description in LRA Section A1, this revised UFSAR supplement also contained a commitment (Commitment No. 41) in LRA Section A4 to implement enhancements to the existing operating experience review activities. Specifically, Commitment No. 41 states that the enhancements to the OEP and CAP will be implemented by December 31, 2014.

The staff's position, as described LR-ISG-2011-05, is that any enhancements to the existing operating experience review activities should be put in place no later than the date the renewed operating licenses are issued and should be implemented on an ongoing basis throughout the respective terms of the renewed licenses. Based on the staff's (then-current) review schedule for the LRA, the December 31, 2014, implementation schedule could be after issuance of the renewed operating licenses. Therefore, the staff determined that the applicant's response did not adequately account for the need to consider operating experience on aging-related degradation and aging management throughout the full terms of the renewed operating licenses. By letter dated November 19, 2012, the staff issued RAI A1-2 requesting that the applicant clarify the UFSAR supplement regarding the implementation schedule for the enhancements to the OEP and CAP. The staff also requested that the applicant provide a justification and include any relevant practical considerations that would impact the implementation timeframe if implementation of the enhancements will occur after issuance of the renewed operating licenses.

The applicant responded to RAI A1-2 by letter dated December 6, 2012. In this response, the applicant revised Commitment No. 41 in LRA Section A4 to indicate that the enhancements to the OEP and CAP will be implemented no later than the date when the renewed operating licenses are issued. The staff reviewed this response and finds it acceptable because it clarifies that the implementation date for the enhancements will coincide with or precede the issuance of the renewed operating licenses, consistent with the guidance in LR-ISG-2011-05. Implementation of these enhancements, in conjunction with the existing operating experience review activities, will ensure that aging-related degradation and aging management are appropriately addressed in the applicant's ongoing process to review plant-specific and industry-generated operating experience.

The staff compared the applicant's UFSAR supplement summary description of the ongoing operating experience review activities, as provided by letters dated June 14, 2012, and December 6, 2012, against the example summary description in LR-ISG-2011-05. The staff determined that the content of the applicant's summary description is consistent with the recommendations in LR-ISG-2011-05 and sufficiently comprehensive to describe the applicant's programmatic operating experience review activities for license renewal. Therefore, the staff finds the summary description acceptable, and the staff's concerns described in RAIs A1-1, A1-2, B1.4-1, and B1.4-3 are resolved.

3.0.5.4 Conclusion

Based on the staff's review of the applicant's programmatic activities for the ongoing review of operating experience, as provided in the LRA, the responses to RAIs A1-1, A1-2, B1.4-1, B1.4-2, and B1.4-3, and in consideration of the guidance contained in LR-ISG-2011-05, the staff concludes that the applicant demonstrated that operating experience will be reviewed on an ongoing basis so that the effects of aging will be adequately managed to maintain the intended functions 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 these activities and concludes that it provides an adequate summary description, as required by 10 CFR 54.21(d).

3.1 Aging Management of Reactor Vessel, Internals, and Reactor Coolant System

This section of the SER documents the staff's review of the applicant's AMR results for the components and component groups of the following:

- reactor vessel and internals
- reactor coolant system
- pressurizer
- steam generators

3.1.1 Summary of Technical Information in the Application

LRA Section 3.1 provides AMR results for the RV and internals, RCS, pressurizer, and SGs. LRA Table 3.1.1, "Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for 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 RV and internals, RCS, pressurizer, and SG 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 operating experience review included industry sources, a review of the GALL Report, and operating experience issues identified since the issuance of the GALL Report.

3.1.2 Staff Evaluation

The staff reviewed LRA Section 3.1 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for the RV and internals, RCS, pressurizer, and SG components within the scope of license renewal and subject to an AMR, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff conducted an onsite audit to examine the applicant's AMPs and related documentation to confirm the applicant's claims that certain AMPs were consistent with the corresponding GALL Report AMPs. The staff did not repeat its review of the matters described in the GALL Report. The staff's evaluations of the AMPs are documented in SER Section 3.0.3.

The staff reviewed the AMRs to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did confirm that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. Details of the staff's evaluation are discussed in SER Sections 3.1.2.1 and 3.1.2.2.

The staff also reviewed the AMRs not consistent with, or not addressed in, the GALL Report. The review evaluated whether all plausible aging effects were identified and whether the aging effects listed were appropriate for the combination of materials and environments specified. Details of the staff's evaluation are discussed in SER Section 3.1.2.3.

For components 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 confirm the applicant's claims.

Table 3.1-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.1 and addressed in the GALL Report.

Table 3.1-1 Staff Evaluation for Reactor Vessel, Reactor Vessel Internals, and Reactor Coolant System Components in the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel pressure vessel support skirt and attachment welds (3.1.1.1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes, TLAA	Not applicable to STP, STP RVs have no support skirt	Not applicable to STP (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 are to be addressed for Class 1 components	Yes, TLAA	Boiling water reactor (BWR) only	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; 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 are to be addressed for Class 1 components	Yes, TLAA	BWR only	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) check code limits for allowable cycles (< 7,000 cycles) of thermal stress range	Yes, TLAA	BWR only	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	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Fatigue is a TLAA (see SER Sections 3.1.2.2.1 and 4.3)
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	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Fatigue is a TLAA (see SER Sections 3.1.2.2.1 and 4.3)
Steel and stainless steel RCPB closure bolting, head closure studs, support skirts and attachment welds, pressurizer relief tank components, SG 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	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Fatigue is a TLAA (see SER Sections 3.1.2.2.1 and 4.3)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel; stainless steel; and 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 are to be addressed for Class 1 components	Yes, TLAA	TLAA, evaluated in accordance with 10 CFR 54.21(c), and environmental effects are to be addressed for Class 1 components	Fatigue is a TLAA (see SER Sections 3.1.2.2.1 and 4.3)
Steel; stainless steel; steel with Ni-alloy or stainless steel cladding; Ni-alloy RV components: flanges; nozzles; penetrations; pressure housings; safe ends; thermal sleeves; vessel shells, heads, and welds (3.1.1.9)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c), and environmental effects are to be addressed for Class 1 components	Yes, TLAA	TLAA, evaluated in accordance with 10 CFR 54.21(c), and environmental effects are to be addressed for Class 1 components	Fatigue is a TLAA (see SER Sections 3.1.2.2.1 and 4.3)
Steel; stainless steel; steel with Ni-alloy or stainless steel cladding; Ni-alloy SG components (flanges; penetrations; nozzles; safe ends, lower heads, and welds) (3.1.1.10)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c), and environmental effects are to be addressed for Class 1 components	Yes, TLAA	TLAA, evaluated in accordance with 10 CFR 54.21(c), and environmental effects are to be addressed for Class 1 components	Fatigue is a TLAA (see SER Sections 3.1.2.2.1 and 4.3)
Steel top head enclosure (without cladding) top head nozzles (vent, top head spray or reactor core isolation cooling (RCIC), and spare) exposed to reactor coolant (3.1.1.11)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	BWR only	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Steel SG 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, detection of aging effects is to be evaluated.	Once-through steam generator (OTSG) only	Applicable to OTSGs; therefore, not applicable to STP (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 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	BWR only	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel, Ni alloy, and 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	BWR only	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel, steel with Ni-alloy or stainless steel cladding, and 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	BWR only	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Steel SG upper and lower shell and transition cone exposed to secondary feedwater and steam (3.1.1.16)	Loss of material due to general, pitting, and crevice corrosion	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry. For Westinghouse Model 44 and 51 SGs, if general, and if pitting corrosion of the shell is known to exist, additional inspection procedures are to be developed.	Yes, detection of aging effects is to be evaluated.	Not applicable to STP	Consistent with NUREG-1801 (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	TLAA, evaluated in accordance with Appendix G of 10 CFR Part 50 and RG 1.99	Loss of fracture toughness is a TLAA (see SER Sections 3.1.2.2.3 and 4.2)

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 (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, plant-specific	Reactor Vessel 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 intergranular stress-corrosion cracking (IGSCC)	A plant-specific AMP is to be evaluated.	Yes	BWR only	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	Inservice Inspection (IWB, IWC, and IWD), Water Chemistry, and plant-specific verification program	Yes	BWR only	Not applicable to PWRs (see SER Section 3.1.2.1.1)
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, TLAA	TLAA	Crack growth due to cyclic loading is a TLAA (see SER Sections 3.1.2.2.5 and 4.7.4)
Stainless steel (SS, including CASS, PH SS or martensitic SS) or nickel alloy Westinghouse reactor vessel internal "Existing Programs" components (3.1.1.22)	Loss of fracture toughness due to thermal aging and neutron irradiation embrittlement, and for CASS, martensitic SS, and PH 5S due to thermal aging embrittlement; or changes in dimensions due to void swelling or distortion: or loss of preload due to thermal and irradiation enhanced stress relaxation or creep: or loss of material due to wear	UFSAR supplement commitment to: (1) participate in industry RVI aging programs; (2) implement applicable results; and (3) submit for staff approval, > 24 months before the period of extended operation, an RVI inspection plan based on industry recommendation.	No	PWR Vessel Internals (B2.1.35)	Consistent with the GALL Report (see SER Section 3.1.2.2.6)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel RV closure head flange leak detection line and BMI guide tubes (3.1.1.23)	Cracking due to SCC	A plant-specific AMP is to be evaluated.	Yes, detection of aging effects is to be evaluated	Water Chemistry and ASME Section XI ISI (Subsection IWB, IWC, and IWD) programs	Consistent with the GALL Report (see SER Section 3.1.2.2.7, item 1)
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, plant-specific	Water Chemistry, and, for CASS components that do not meet the NUREG-0313 guidelines, ASME Code Section XI ISI (IWB, IWC, and IWD) Program	Consistent with the GALL Report (see SER Section 3.1.2.2.7, item 2, for CASS piping)
Stainless steel jet pump sensing line (3.1.1.25)	Cracking due to cyclic loading	A plant-specific AMP is to be evaluated.	Yes	BWR only	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	Inservice Inspection (IWB, IWC, and IWD) and plant-specific verification program	Yes	BWR only	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel (SS, including CASS, PH SS or martensitic SS) or nickel alloy Westinghouse reactor vessel internal "Expansion" components (3.1.1.27)	Loss of fracture toughness due to neutron irradiation embrittlement and for CASS, martensitic SS, and PH SS due to thermal aging embrittlement, or changes in dimensions due to void swelling or distortion: or loss of preload due to thermal and irradiation enhanced stress relaxation or creep, or loss of material due to wear	XI.M16A PWR Vessel Internals	No	PWR Vessel Internals (B.2.1.35)	Consistent with the GALL Report (see SER Section 3.1.2.2.9)

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 SG 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, plant-specific	Not applicable to STP—STP SGs do not have feedwater impingement plates.	Not applicable to STP (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	BWR only	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel or nickel alloy Westinghouse RVI “Primary” components (3.1.1.30)	Cracking due to SCC and irradiation-assisted stress corrosion cracking (IASCC) or fatigue	Water Chemistry (B2.1.2) and PWR Vessel Internals (B2.1.35)	No	Water Chemistry Program and UFSAR supplement: (1) AMR items for RVI components conform with LR-ISG-2011-04, (2) a plant-specific RVI inspection plan (RVIIP) is based on the MRP-227-A report, (3) plant-specific AMP for the RVI components is based on the MRP-227-A report, and (4) appropriately addressed and resolved those A/LAIs that pertain to these components	Consistent with the GALL Report (see SER Section 3.1.2.2.12)
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	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry and UFSAR supplement commitment to implement applicable plant commitments to: (1) NRC orders, bulletins, and GLs associated with Ni alloys, and (2) staff-accepted industry guidelines.	No, but applicant commitment needs to be confirmed.	Nickel-Alloy Aging Management, ASME Code Section XI Inservice Inspection IWB, IWC, and IWD, Water Chemistry, compliance with NRC orders, and implementation of bulletins, GLs, and staff-accepted industry guidelines	Consistent with GALL Report (see SER Section 3.1.2.2.13)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel SG 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, plant-specific	SG Tube Integrity and Water Chemistry programs	Consistent with the GALL Report (see SER Section 3.1.2.2.14)
Stainless steel (SS, including CASS, PH SS or martensitic SS) or nickel alloy Westinghouse RVI “Primary" components (3.1.1.33)	Loss of fracture toughness due to neutron irradiation embrittlement and for CASS, martensitic SS, and PH SS due to thermal aging embrittlement; or changes in dimensions due to void swelling or distortion; or loss of preload due to thermal and irradiation enhanced stress relaxation or creep; or loss of material due to wear	XI.M16A, PWR Vessel Internals	No	PWR Vessel Internals (B2.1.35)	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	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry. For Ni alloy, UFSAR supplement commitment to implement applicable plant commitments to: (1) NRC orders, bulletins, and GLs associated with Ni alloys, and (2) staff-accepted industry guidelines.	No, but applicant commitment needs to be confirmed.	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and Water Chemistry Program	Consistent with the GALL Report (see SER Section 3.1.2.2.16, item 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 with stainless steel or Ni-alloy cladding primary side components; SG upper and lower heads, tubesheets, and tube-to-tubesheet welds (3.1.1.35)	Cracking due to SCC and PWSCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry. For Ni alloy, UFSAR supplement commitment to implement applicable plant commitments to: (1) NRC orders, bulletins, and GLs associated with Ni alloys, and (2) staff-accepted industry guidelines.	No, but applicant commitment needs to be confirmed.	For components applicable to STP: ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and Water Chemistry Program	Applicable to OTSGs; therefore, not applicable to STP, except for tube-to-tubesheet welds between Ni-alloy cladding and Ni-alloy tubes in the SG (see SER Sections 3.1.2.1.1 and 3.1.2.2.16, item 1)
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, unless applicant commitment needs to be confirmed.	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.	Consistent with the GALL Report; the STP pressurizer spray head is stainless steel (see SER Section 3.1.2.2.16)
Stainless steel or nickel alloy Westinghouse RVI "Existing Programs" components (3.1.1.37)	Cracking due to SCC, PWSCC, IASCC, or fatigue	XI.M16A, “PWR Vessel Internals” and XI.M2, “Water Chemistry”	No	Water Chemistry (B2.1.2) and PWR Vessel Internals (B2.1.35)	Consistent with the GALL Report (see SER Section 3.1.2.1.7)
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	BWR only	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	BWR only	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 penetrations for CRD stub tubes instrumentation, jet pump instrumentation, standby liquid control, flux monitor, and drain line exposed to reactor coolant (3.1.1.40)	Cracking due to SCC, IGSCC, and cyclic loading	BWR Penetrations and Water Chemistry	No	BWR only	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel and Ni-alloy piping, piping components, and piping elements ≥ 4 in. NPS; nozzle safe ends and associated welds (3.1.1.41)	Cracking due to SCC and IGSCC	BWR SCC and Water Chemistry	No	BWR only	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	BWR only	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	BWR only	Not applicable to PWRs (see SER Section 3.1.2.1.1)
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	BWR only	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	BWR only	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	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry	No	BWR only	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 RVIs exposed to reactor coolant (3.1.1.47)	Loss of material due to pitting and crevice corrosion	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry	No	BWR only	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Steel and stainless steel Class 1 piping, fittings, and branch connections < 4 in. NPS exposed to reactor coolant (3.1.1.48)	Cracking due to SCC, IGSCC (for stainless steel only), and thermal and mechanical loading	Inservice Inspection (IWB, IWC, and IWD), Water Chemistry, and One-Time Inspection of ASME Code Class 1 Small-Bore Piping	No	BWR only	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	Inservice Inspection (IWB, IWC, and IWD), Water Chemistry, and, for BWRs with a crevice in the access hole covers, augmented inspection using UT or other demonstrated acceptable inspection of the access hole cover welds	No	BWR only	Not applicable to PWRs (see SER Section 3.1.2.1.1)
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	BWR only	Not applicable to PWRs (see SER Section 3.1.2.1.1)
CASS jet pump assembly castings; orificed fuel support (3.1.1.51)	Loss of fracture toughness due to thermal aging and neutron irradiation embrittlement	Thermal Aging and Neutron Irradiation Embrittlement of CASS	No	BWR only	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 (see SER Section 3.1.2.1.4)

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
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 to STP	Not applicable to STP (see SER Section 3.1.2.1.1)
CASS Class 1 pump casings, and valve bodies and bonnets exposed to reactor coolant > 250 °C (482 °F) (3.1.1.55)	Loss of fracture toughness due to thermal aging embrittlement	Inservice inspection (IWB, IWC, and IWD). Thermal aging susceptibility screening is not necessary, ISI requirements are sufficient for managing these aging effects. ASME Code Case N-481 also provides an alternative for pump casings.	No	ASME Section XI ISI (IWB, IWC, and IWD) Program. 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.	Consistent with the GALL Report
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 to STP	Not applicable to STP (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 > 250 °C (482 °F) (3.1.1.57)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS	No	Thermal Aging Embrittlement of CASS Program	Not applicable to STP (see SER Section 3.1.2.1.6)
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 GALL Report (see SER Section 3.1.2.1.5)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel SG steam nozzle and safe end, feedwater nozzle and safe end, AFW nozzles and safe ends exposed to secondary feedwater/steam (3.1.1.59)	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	No	Flow-Accelerated Corrosion	Consistent with the GALL Report
Stainless steel flux thimble tubes (with or without chrome plating) “Existing Programs” component (3.1.1.60)	Loss of material due to wear	Flux Thimble Tube Inspection	No	Flux Thimble Tube Inspection Program	Consistent with the GALL Report
Stainless steel, steel pressurizer integral support exposed to air with metal temperature up to 288 °C (550 °F) (3.1.1.61)	Cracking due to cyclic loading	Inservice Inspection (IWB, IWC, and IWD)	No	ASME Section XI ISI (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	Inservice Inspection (IWB, IWC, and IWD)	No	ASME Section XI ISI (IWB, IWC, and IWD) Program	Consistent with the GALL Report
Stainless steel, nickel alloy, or CASS reactor vessel internals, core support structure components in MRP-227-A, exposed to reactor coolant and neutron flux (3.1.1.63)	Cracking or loss of material due to wear	Inservice Inspection (IWB, IWC, and IWD) or XI.M16A, “PWR Vessel”	No	Inservice Inspection (IWB, IWC, and IWD) (B2.1.1) or PWR Vessel Internals (B2.1.35)	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	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry	No	ASME Section XI ISI (IWB, IWC, and IWD) and Water Chemistry programs	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 RV upper head and CRD penetration nozzles, instrument tubes, head vent pipe (top head), and welds (3.1.1.65)	Cracking due to PWSCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry and Ni-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors	No	ASME Section XI Inservice Inspection (IWB, IWC, and IWD), Water Chemistry, and Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors programs	Consistent with the GALL Report
Steel SG secondary manways and handholds (cover only) exposed to air with leaking secondary-side water, steam, or both (3.1.1.66)	Loss of material due to erosion	Inservice Inspection (IWB, IWC, and IWD) for Class 2 components	No	OTSG only	Applicable to OTSGs; therefore, not applicable to STP (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	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry	No	ASME Section XI ISI (IWB, IWC, and IWD) and Water Chemistry programs	Consistent with the GALL Report
Stainless steel, steel with stainless steel cladding Class 1 piping, fittings, pump casings, valve bodies, nozzles, safe ends, manways, flanges, CRD housing; pressurizer heater sheaths, sleeves, diaphragm plate; pressurizer relief tank components, RCS cold leg, hot leg, surge line, and spray line piping and fittings (3.1.1.68)	Cracking due to SCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry	No	ASME Section XI ISI (IWB, IWC, and IWD) and Water Chemistry programs	Consistent with the GALL Report (see Section 3.1.2.1.8)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
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	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry	No	Nickel-Alloy Aging Management, ASME Section XI Inservice Inspection IWB, IWC, and IWD, Water Chemistry, compliance with NRC orders, and implementation of bulletins, GLs, and staff-accepted industry guidelines	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 in. NPS exposed to reactor coolant (3.1.1.70)	Cracking due to SCC and thermal and mechanical loading	Inservice Inspection (IWB, IWC, and IWD), Water Chemistry, and One-Time Inspection of ASME Code Class 1 Small-Bore Piping	No	ASME Section XI ISI (IWB, IWC, and IWD) and Water Chemistry programs and One-Time Inspections of small-bore piping performed by the ASME Section XI ISI (IWB, IWC, and IWD) 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
Ni-alloy SG tubes and sleeves exposed to secondary feedwater/steam (3.1.1.72)	Cracking due to outside-diameter stress -corrosion cracking (ODSCC) and intergranular attack; loss of material due to fretting and wear	Steam Generator Tube Integrity and Water Chemistry	No	Steam Generator Tube Integrity and Secondary Water Chemistry programs	Consistent with the GALL Report
Ni-alloy SG 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 and Water Chemistry programs	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
Chrome plated steel, stainless steel, Ni-alloy SG anti-vibration bars exposed to secondary feedwater/steam (3.1.1.74)	Cracking due to SCC; loss of material due to crevice corrosion and fretting	Steam Generator Tube Integrity and Water Chemistry	No	Steam Generator Tube Integrity and Water Chemistry programs	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	OTSG only	Applicable to OTSGs; therefore, not applicable to STP (see SER Section 3.1.2.1.1)
Steel SG 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; ligament cracking due to corrosion	Steam Generator Tube Integrity and Water Chemistry	No	Steam Generator Tube Integrity and Water Chemistry programs	Consistent with the GALL Report; ligament cracking due to corrosion is not applicable to the tube support plates since they are stainless steel
Ni-alloy SG 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 to STP	Not applicable (see SER Section 3.1.2.1.1)
Steel SG 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 to STP	Not applicable (see SER Section 3.1.2.1.1)
Ni-alloy SG 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 to STP	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
Stainless steel Westinghouse RVI “Expansion” components (3.1.1.80)	Cracking due to stress corrosion cracking, irradiation-assisted stress corrosion cracking, or fatigue	Water Chemistry (B2.1.2) and PWR Vessel Internals	No	Water Chemistry (B2.1.2) and PWR Vessel Internals (B2.1.35)	Consistent with the GALL Report (see SER Section 3.1.2.1.7)
Ni-alloy or Ni-alloy clad SG divider plate exposed to reactor coolant (3.1.1.81)	Cracking due to PWSCC	Water Chemistry	No	Water Chemistry Program	Consistent with the GALL Report (see Section 3.1.2.1.8)
Stainless steel SG primary side divider plate exposed to reactor coolant (3.1.1.82)	Cracking due to SCC	Water Chemistry	No	Not applicable to STP	Not applicable to STP (see SER Section 3.1.2.1.1)
Stainless steel; steel with Ni-alloy or stainless steel cladding; and 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 and One-Time Inspection Program	Consistent with the GALL Report (see SER Section 3.1.2.1.3)
Ni-alloy SG components, such as secondary-side nozzles (vent, drain, and instrumentation) exposed to secondary feedwater/steam (3.1.1.84)	Cracking due to SCC	Water Chemistry and One-Time Inspection or Inservice Inspection (IWB, IWC, and IWD)	No	OTSG only	Applicable to OTSGs; therefore, not applicable to STP (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	NA—No AERM or AMP	None	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 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	NA—No AERM or AMP	None	Consistent with the GALL Report
Steel piping, piping components, and piping elements in concrete (3.1.1.87)	None	None	NA—No AERM or AMP	None	Not applicable to STP (see SER Section 3.1.2.1.1)

The staff's review of the RCS component groups followed several approaches. One approach, documented in SER Section 3.1.2.1, discusses the staff's review of AMR results for components 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 AMR Results That Are Consistent with the GALL Report

LRA Section 3.1.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the RV, RVIs, RCS, and SG components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
- Bolting Integrity
- Boric Acid Corrosion
- External Surfaces Monitoring Program
- Flow-Accelerated Corrosion
- Flux Thimble Tube Inspection
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Lubricating Oil Analysis
- Nickel-Alloy Aging Management
- Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors

- One-Time Inspection
- One-Time Inspection of ASME Code Class 1 Small-Bore Piping
- PWR Reactor Internals
- Reactor Head Closure Studs
- Reactor Vessel Surveillance
- Steam Generator Tube Integrity
- Water Chemistry

LRA Tables 3.1.2-1 through 3.1.2-4 summarize the results of AMRs for the RV and internals, RCS, pressurizer, and SG components and indicate AMRs claimed to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant had claimed consistency and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine whether the plant-specific components in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR item describing how the information in the tables aligns with the information in the GALL Report. The staff reviewed those AMRs with notes A through E, which indicate how the AMR was consistent with the GALL Report.

Note A indicates that the AMR 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 confirm 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 confirm 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 confirm 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 confirm 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 had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR 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 confirm consistency with the GALL Report and determined whether the identified AMP would manage the aging effect consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

The staff audited and reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, it did confirm that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. The staff's evaluation is discussed below.

The staff reviewed the LRA to confirm that the applicant did the following:

- provided a brief description of the system, components, materials, and environments
- stated that the applicable aging effects were reviewed and evaluated in the GALL Report
- identified those aging effects for the RV and internals, RCS, pressurizer, and SG components that are subject to an AMR

On the basis of its audit and review, the staff determines that, for AMRs not requiring further evaluation—as identified in LRA Table 3.1.1—the applicant's references to the GALL Report are acceptable, and no further staff review is required.

3.1.2.1.1 AMR Results Identified as Not Applicable

For item 3.1.1.1, the applicant stated that the corresponding AMR items are not applicable since STP RVs have no support skirt. The staff reviewed the LRA and the UFSAR, and finds this item is not applicable to STP.

For items 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, and 3.1.1.38 through 3.1.1.51 in LRA Table 3.1.1, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable because the associated items are only applicable to BWRs. The staff reviewed the SRP-LR, confirmed these items only apply to BWRs, and finds these items are not applicable to STP.

For items 3.1.1.12, 3.1.1.35, 3.1.1.66, 3.1.1.75, and 3.1.1.84 in LRA Table 3.1.1, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable because the associated items are only applicable to once-through steam generators (OTSGs). The staff reviewed the SRP-LR, confirmed these items only apply to OTSGs (with one exception noted below), and finds these items are not applicable to STP. For item 3.1.1.35, the staff determined that the item also applied to nickel alloy tube-to-tubesheet welds in the applicant's SGs; the staff's evaluation of that issue is documented in SER Section 3.1.2.2.16, item 1.

LRA Table 3.1.1, item 3.1.1.54 is associated with managing copper-alloy piping, piping components, and piping elements exposed to CCCW for loss of material due to pitting, crevice, and galvanic corrosion. The applicant stated that this item is not applicable to STP because

STP does not have any copper-alloy piping, piping components, or piping elements exposed to CCCW in the RCS, and the applicable items in the GALL Report were not used. The staff reviewed LRA Sections 2.3.1 and 3.1, and the UFSAR, and finds that the applicant's statement is acceptable.

LRA Table 3.1.1, item 3.1.1.56, is associated with managing copper alloy greater than 15 percent Zn piping, piping components, and piping elements exposed to CCCW for loss of material due to selective leaching. The applicant stated that this item is not applicable to STP because STP does not have any in-scope copper alloy greater than 15 percent Zn components exposed to CCCW in the RCS, and the associated items in the GALL Report were not used. The staff reviewed LRA Sections 2.3.1 and 3.1, and the UFSAR, and finds that the applicant's statement is acceptable.

LRA Table 3.1.1, item 3.1.1.77, is associated with managing nickel-alloy SG tubes and sleeves exposed to phosphate chemistry in secondary feedwater and steam for loss of material due to wastage and pitting corrosion. The applicant stated that this item is not applicable to STP because STP uses an all-volatile chemistry control program in its SGs, not a phosphate chemistry control program. The staff reviewed LRA Sections 2.3.1 and 3.1, and the UFSAR, and finds that the applicant's statement is acceptable.

LRA Table 3.1.1, item 3.1.1.78, is associated with managing steel SG tube support lattice bars exposed to secondary feedwater and steam for wall thinning due to flow-accelerated corrosion. The applicant stated that this item is not applicable to STP because STP SGs do not contain any lattice bars, and the associated items in the GALL Report were not used. The staff reviewed LRA Sections 2.3.1 and 3.1, and the UFSAR, and finds that the applicant's statement is acceptable.

LRA Table 3.1.1, item 3.1.1.79, is associated with managing nickel-alloy SG tubes exposed to secondary feedwater and steam for denting due to corrosion of the steel tube support plate. The applicant stated that this item is not applicable to STP since STP SGs do not have steel tube support plates; therefore, tube denting due to corrosion of the steel tube support plates is not applicable. The staff reviewed LRA Sections 2.3.1 and 3.1, and the UFSAR, and finds that the applicant's statement is acceptable.

LRA Table 3.1.1, item 3.1.1.82, is associated with managing stainless steel SG primary side divider plate exposed to reactor coolant for cracking due to SCC. The applicant stated that this item is not applicable to STP because STP SG divider plates are nickel alloy, and the associated items in the GALL Report were not used. The staff reviewed LRA Sections 2.3.1 and 3.1, and the UFSAR, and finds that the applicant's statement is acceptable.

LRA Table 3.1.1, item 3.1.1.87, is associated with steel piping, piping components, and piping elements in concrete for which no aging effect or mechanism is stated. The applicant stated that this item is not applicable to STP because STP does not have any in-scope steel piping, piping components, or piping elements in RV, RVI, or RCS components embedded in concrete, and the associated items in the GALL Report were not used. The staff reviewed LRA Sections 2.3.1 and 3.1, and the UFSAR, and finds that the applicant's statement is acceptable.

3.1.2.1.2 Cracking Due to Primary Water Stress Corrosion Cracking

LRA Table 3.1.1, item 3.1.1.69, addresses stainless steel, nickel alloy safety injection nozzles, safe ends, and associated welds and buttering exposed to reactor coolant, which will be managed for cracking due to PWSCC. For the AMR item that cites generic note E, the LRA credits the Nickel-Alloy Aging Management, ASME Section XI Inservice Inspection IWB, IWC, and IWD, and Water Chemistry programs as well as compliance with NRC orders and implementation of bulletins, GLs, and staff-accepted industry guidelines to manage the aging effect of cracking due to PWSCC. The GALL Report recommends GALL Report AMP XI.M1, "Inservice Inspection (IWB, IWC, and IWD)," and the GALL Report AMP XI.M2, "Water Chemistry," to ensure that these aging effects are adequately managed.

The staff's evaluation of the applicant's Nickel-Alloy Aging Management, ASME Section XI Inservice Inspection IWB, IWC, and IWD, and Water Chemistry programs are documented in SER Sections 3.0.3.3.1, 3.0.3.1.1, and 3.0.3.2.1, respectively. These AMPs were found to be consistent with the GALL Report or sufficient to manage the aging of components within the scope of the AMP. While the staff notes that there is one difference in the titles of the AMPs proposed by the applicant and those recommended by the GALL Report, Revision 1, due to recent changes in 10 CFR 50.55a, there is no effective difference in these approaches. The GALL Report recommends, and the LRA proposes, that Water Chemistry and Inservice Inspection AMPs be used to manage aging. As stated above, both of these LRA AMPs have been found to be consistent with their corresponding GALL Report AMP. Pursuant to 10 CFR 50.55a, additional inspections are required, as compared to the Inservice Inspection Program. These inspections were formerly described in NRC generic communications. The applicant incorporated these requirements into its Nickel Alloy Management Program, which, as indicated above, has been found sufficient to manage aging of these components. In its review of components associated with item 3.1.1.69 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Nickel-Alloy Aging Management, ASME Section XI Inservice Inspection IWB, IWC, and IWD, and Water Chemistry programs acceptable because the applicant's programs are in compliance with 10 CFR 50.55a and because the GALL Report does not recommend aging management activities in addition to the regulatory requirements.

The staff concludes that, for LRA item 3.1.1.69, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.3 Loss of Material Due to Pitting and Crevice Corrosion

LRA Table 3.1.1, item 3.1.1.83, addresses stainless steel, steel with nickel alloy or stainless steel cladding, and nickel alloy RVIs and RCPB components exposed to reactor coolant, which will be managed for loss of material due to pitting and crevice corrosion. For the AMR items that cite generic note E, the LRA credits the Water Chemistry and One-Time Inspection programs to manage the aging effect for stainless steel RVIs and RCPB components. The GALL Report recommends GALL Report AMP XI.M2, "Water Chemistry," to ensure that these aging effects are adequately managed.

GALL Report AMP XI.M2 recommends using water chemistry control to minimize contaminant concentration to manage aging. The staff noted that the Water Chemistry and One-Time Inspection programs propose to manage the aging of stainless steel RVIs and RCPB components through the use of water chemistry controls to minimize contaminant concentrations along with a one-time visual inspection to confirm the effectiveness of the Water Chemistry Program.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection programs are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.4, respectively. In its review of components associated with item 3.1.1.83, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Water Chemistry and One-Time Inspection programs acceptable because the Water Chemistry Program establishes the plant water chemistry control parameters and their limits to mitigate aging and identifies the actions required if the parameters exceed the limits, and the One-Time Inspection Program prescribes appropriate visual, volumetric, or other inspection techniques capable of detecting pitting and crevice corrosion prior to loss of intended function to confirm the effectiveness of the water chemistry controls.

The staff concludes that, for LRA item 3.1.1.83, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.4 Cracking Due to Stress Corrosion Cracking

LRA Table 3.1.1, item 3.1.1.52, addresses 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 exposed to borated water leakage (exterior), which will be managed for cracking due to SCC, loss of material due to wear, loss of preload due to thermal effects, gasket creep, and self-loosening. The staff noted that based on a review of the applicant's UFSAR, the steel closure materials used for RCPB applications (e.g., SA-540, SA-453 Grade 660) do not exceed the 170 ksi threshold for SCC stated in RG 1.65, October 1973. During its review of components associated with item 3.1.1.52, for which the applicant cited generic note B, the staff noted that the stainless steel closure bolting in LRA Tables 3.2.2-1, 3.2.2-4, 3.3.2-8, 3.3.2-19, 3.3.2-22, 3.3.2-23, and 3.3.2-27, associated with item 3.1.1.52, were not managed for cracking. By letter dated September 22, 2011, the staff issued RAI 3.2.2.1-1 requesting that the applicant either state why cracking is not a managed aging effect for these components or update the LRA to show that cracking is being managed for these components.

In its response dated November 21, 2011, the applicant stated that GALL Report Section IX.D states a 60 °C (140 °F) threshold for SCC of stainless steel material, and the components in the above stated tables are in an ambient temperature less than 60 °C (140 °F); therefore, SCC is not an applicable aging effect.

The staff noted the following:

- Based on the applicant's response, the closure bolts are not exposed to an ambient temperature above 60 °C (140 °F).
- As stated in the GALL Report, Section IX.D, SCC can only occur at ambient conditions (i.e., less than 60 °C (140 °F)) when the material is exposed to chemicals that could cause cracks to initiate.
- Section IX.D also states that these are considered event-driven conditions resulting from a breakdown of chemistry controls.

- Event-driven environmental impacts are addressed by the applicant's CAP.
- SRP-LR Section A.1.2.1, item 7, states, "[s]pecific aging effects from abnormal events need not be postulated for license renewal."

Therefore, the staff finds the applicant's response acceptable for 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 exposed to borated water leakage (exterior) because the closure bolts are not exposed to an aging-related environment that would result in SCC.

However, the staff also noted that NRC Inspection Report No. 05000449/2011005, dated February 13, 2012 (ADAMS Accession No. ML120300394), describes a safety injection system hot leg check valve on which a seal cap enclosure had been installed in 1997 because of reactor coolant leakage past the body to bonnet gasket. The enclosure surrounds the valve bolting, preventing direct inspection. The staff also noted that the inspection report describes recurring reactor coolant leakage from the seal cap enclosure, indicating that the bolts within the enclosure may be submerged in a reactor coolant environment that is conducive to SCC. Based on the new potential conditions identified in the report, the staff found the applicant's response to RAI 3.2.2.1-1 unacceptable. By letter dated May 14, 2012, the staff issued followup RAI 3.2.2.1-1a requesting that the applicant describe, for all pressure-retaining bolting surrounded by seal cap enclosures, the bolting alloy and the leaking water environment; new AMR items for the aging management of the bolting for loss of material, loss of preload, and cracking due to SCC in the submerged environment; and technical justification for how the aging effects above are managed if direct inspection is not possible. A second request in RAI 3.2.2.1-1a addresses operating experience in the Boric Acid Control Program related to recurring RCP leakage; this request is documented in SER Section 3.0.3.2.3.

In its response dated May 14, 2012, the applicant stated that the seal cap enclosures are currently installed on safety injection system check valve SI0010A in Unit 2 and on chemical volume control system check valves CV0001, CV0002, CV0004, and CV0005 in both Unit 1 and Unit 2. The applicant also stated that the bolting alloy is A-286 steel, which is an iron-based and precipitation-hardened high-strength material with high chrome and high nickel content, specifically designed to be resistant to boric acid corrosion. The applicant further stated that it will permanently remove the seal cap enclosures at the next available opportunity and will follow that up either with replacement of the affected bolts underneath or with direct inspection for intergranular SCC. The applicant added Commitment No. 43 to LRA Table A4-1, which commits to removing the seal cap enclosures and performing the followup actions by the 2012 RFO (Unit 1) and by the 2013 RFO (Unit 2). By letters dated October 28, 2013, and October 22, 2014, the applicant informed the NRC that these actions have been completed.

The staff finds the applicant's response acceptable because the applicant committed to remove the seal cap enclosures at the next available opportunity and will inspect or replace the bolting immediately afterwards. The staff notes that after the seal cap enclosures are removed, the bolted joints will be exposed to an environment of borated water leakage, as is currently described in the LRA, and will be managed for aging during the period of extended operation by the Boric Acid Corrosion and Bolting Integrity AMPs.

Furthermore, the staff notes that LRA Section A0 of Appendix A states that the summary descriptions of license renewal commitments (contained in Section A4) will be incorporated into the UFSAR update following issuance of the renewed operating license in accordance with

10 CFR 50.71(e). The inclusion of the list of commitments in the UFSAR provides assurance that the seal cap enclosures will be removed as described in Commitment No. 43 by the 2012 RFO (Unit 1) and by the 2013 RFO (Unit 2). The staff's concerns described in RAIs 3.2.2.1-1 and 3.2.2.1-1a are resolved.

The staff concludes that for LRA item 3.1.1.52 the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.5 Loss of Material Due to Boric Acid Corrosion

LRA Table 3.1.1, item 3.1.1.58, addresses steel RCPB external surfaces exposed to air with borated water leakage, which will be managed for loss of material due to boric acid corrosion. The LRA credits the Boric Acid Corrosion Program to manage the aging effect. During its review of components associated with item 3.1.1.58, for which the applicant cited generic note A, the staff noted that the updated staff guidance in SRP-LR Revision 2, Table 3.1-1, item 48, states that steel external surfaces—including RV top head, bottom head, and RCPB piping or components adjacent to dissimilar metal welds exposed to air with borated water leakage—should be managed for loss of material due to boric acid corrosion by GALL Report AMP XI.M10, "Boric Acid Corrosion," and GALL Report AMP XI.M11B, "Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components." The staff also noted that the GALL Report AMP XI.M11B program description states that inspection activities should be in accordance with 10 CFR 50.55a, including ASME Code Cases N-722-1 and N-729-1, and industry guidelines for inspection of primary system butt welds (e.g., MRP-139). It is not clear to the staff whether the applicant's Boric Acid Corrosion Program contains the elements of GALL Report AMP XI.M11B that are relevant to loss of material (i.e., requirements in 10 CFR 50.55a, including Code Cases N-722-1 and N-729-1, and MRP-139). By letter dated September 22, 2011, the staff issued RAI 3.1.1.58-1 requesting that the applicant clarify whether the inservice inspections in the Boric Acid Corrosion Program are in accordance with 10 CFR 50.55a, including ASME Code Cases N-722-1 and N-729-1, and MRP-139. If not, the applicant was asked to provide information on what equivalent inspection activities will be used to manage loss of material due to boric acid corrosion of steel components in the vicinity of nickel alloy RCPB components.

In its response dated October 25, 2011, the applicant stated that the Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program requires implementation of ASME Code Case N-729-1, and the Nickel-Alloy Aging Management Program requires implementation of ASME Code Case N-722-1 and examinations consistent with MRP-139. The staff finds the applicant's response acceptable because the elements of GALL Report AMP XI.M11B that are relevant to loss of material (i.e., requirements in 10 CFR 50.55a, including Code Cases N-722-1 and N-729-1, and MRP-139) are included in the Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program and the Nickel-Alloy Program. The staff's concern described in RAI 3.1.1.58-1 is resolved.

The staff's evaluation of the applicant's Boric Acid Corrosion Program, Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program, and Nickel-Alloy Program are documented in SER Sections 3.0.3.2.3, 3.0.3.1.2, and 3.0.3.3.1, respectively. Based on its review of components associated with item 3.1.1.58, for which the applicant cited generic note A, the staff finds the applicant's proposal to manage aging using the Boric Acid Corrosion Program acceptable because, in combination with the Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program and Nickel-Alloy Program, the inspection activities associated with ASME Code Cases N-722-1 and N-729-1, and MRP-139, as well as the periodic visual inspections in the Boric Acid Corrosion Program, are capable of ensuring that degradation of steel components will be detected prior to loss of intended functions.

The staff concludes that for LRA item 3.1.1.58, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.6 Loss of Fracture Toughness Due to Thermal Aging and Neutron Irradiation Embrittlement

LRA Table 3.1.1, item 3.1.1.57, addresses CASS Class 1 piping, piping components, piping elements, and CRD pressure housings exposed to reactor coolant greater than 250 °C (482 °F). SRP-LR Table 3.1-1, ID 57, recommends GALL Report AMP XI.M12, “Thermal Aging Embrittlement of Cast Austenitic Stainless Steel,” to manage loss of fracture toughness due to thermal aging embrittlement of these components. The applicant indicated that the CRD pressure housings are made of wrought stainless steel; therefore, the GALL Report lines were not used. In its review, the staff noted that UFSAR Table 5.2-2 confirms that the CRD pressure housings are not made of CASS.

In LRA item 3.1.1.57, the applicant stated that portions of the reactor coolant loops are constructed of CASS, that the straight piping pieces are centrifugally cast, and that the fittings are statically cast. In addition, the applicant indicated that thermal aging of CASS reactor coolant piping is not a concern since the molybdenum and ferrite contents for these fittings and piping pieces are below the industry-accepted threshold for thermal aging embrittlement. In comparison, GALL Report AMP XI.M12 states that for low-molybdenum content steels (SA-351 Grades CF3, CF3A, CF8, and CF8A or other steels with molybdenum not exceeding 0.5 wt. percent), only static-cast steels with ferrite greater than 20 percent are potentially susceptible to thermal aging embrittlement. In addition, the GALL Report indicates that for high-molybdenum content steels (SA-351 Grades CF3M, CF3MA, and CF8M or other steels with 2.0 to 3.0 wt. percent molybdenum), only static-cast steels with ferrite greater than 14 percent are potentially susceptible to thermal aging embrittlement.

In its review, the staff noted that UFSAR Table 5.2-2 indicates that the reactor coolant pipe is made of centrifugal-cast SA-351, Grade CF8A, and the reactor coolant fittings are made of SA-351, Grade CR8A. UFSAR Table 5.2-1 indicates that the 1974 edition through winter 1975 of ASME Code Section III is applicable for the construction of the reactor coolant pipe. The staff also noted that the centrifugal-cast SA-351, Grade CF8A (low-molybdenum CASS) is not susceptible to thermal aging embrittlement in accordance with the guidance in the GALL Report. The staff further noted that for the reactor coolant fittings neither the GALL Report nor the 1974 edition of ASME Code Section III, Part A, Specification SA-351 identifies “Grade CR8A” as a material grade for fabrication of Code Class CASS components. Therefore, the staff needed additional information regarding the SA-351 material grade that was used to fabricate the static-cast reactor coolant fittings and the molybdenum and ferrite contents for this material in order to determine the material’s susceptibility to thermal aging embrittlement.

By letter dated September 22, 2011, the staff issued RAI 3.1.1.57-1 requesting that the applicant clarify whether the reference in UFSAR Table 5.2-2 to SA-351 Grade CR8A is accurate and refers to an actual material; if not, the applicant was asked to identify the correct material grade in SA-351 that represents the actual material for the fittings and to provide the information on the molybdenum and ferrite contents of this material. Furthermore, the applicant was asked to justify why this material is not susceptible to loss of fracture toughness due to thermal aging embrittlement. If the material is susceptible to loss of facture toughness, the applicant should propose an AMP to adequately manage the aging effect. If the reference to SA-351 Grade CR8A in UFSAR Table 5.2-2 is correct, the applicant should provide the information on the molybdenum and ferrite contents of the static-cast SA-351 Grade CR8A material and justify why this static-cast stainless steel is not susceptible to loss of fracture toughness due to thermal aging embrittlement.

In its response dated November 21, 2011, the applicant stated that the CMTRs for the reactor coolant fittings show that the fittings were fabricated to the SA-351 Grade CF8A standard, and UFSAR Table 5.2.2 will be revised to show the material of the fittings as SA-351 Grade CF8A. The applicant also stated that a screening process, which was performed in accordance with GALL Report, Revision 2, AMP XI.M12 for STP Class 1 CASS fittings, found that these reactor coolant fittings are not susceptible to thermal aging embrittlement. The screening process evaluated the fittings in accordance with the criteria for static-cast CASS components with low molybdenum contents; the GALL Report considers this type of CASS material to be potentially susceptible to thermal aging embrittlement only if it has a ferrite content in excess of 20 percent. The applicant indicated that the Hull's equivalent factor was used to calculate the ferrite contents of the CASS materials using chemistry data from CMTRs for the materials, and the screening calculation found that the ferrite content of the fittings to be less than 20 percent.

During its review, the staff noted that GALL Report AMP XI.M12 references NUREG/CR-4513, Revision 1, "Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems," August 1994, which addresses the acceptable equations to calculate the Hull's equivalent factor for the estimation of ferrite contents. Therefore, the staff needed to further confirm whether the applicant's screening method for the CASS material susceptibility is consistent with the guidance in NUREG/CR-4513, Revision 1, as referenced in the GALL Report.

By letter dated February 8, 2012, the staff issued followup RAI 3.1.1.57-1a requesting that the applicant provide the bounding case chemical composition of the reactor coolant fittings that estimates the highest ferrite content of these CASS components, including the contents of chromium, molybdenum, silicon, nickel, manganese, nitrogen, and carbon. The staff also requested that the applicant provide the calculated highest ferrite content in order to confirm that the applicant's screening analysis indicates no susceptibility of these CASS fittings to thermal aging embrittlement. In addition, the staff requested that, as part of the response, the applicant clarify if the applicant's susceptibility screening method is consistent with the GALL Report, which addresses the guidance of NUREG/CR-4513, Revision 1, for ferrite content calculations.

In its response dated February 27, 2012, the applicant provided the bounding case chemical composition of Heat Number 17743-1 for Unit 1 and the bounding case composition of Heat Numbers 21389-1 and 21389-2 (identical in composition) for Unit 2. The calculation procedures were also provided for the ferrite contents using the bounding case chemical compositions and the resultant maximum ferrite contents. The staff independently confirmed that the applicant's calculations for the maximum ferrite contents are consistent with the equations and guidance in NUREG/CR-4513, Revision 1, and that the maximum ferrite contents are 14.9 percent and

15.4 percent for Units 1 and 2, respectively, which are less than the susceptibility threshold (20 percent) for static-cast low-molybdenum CASS materials.

Based on its review, the staff finds the applicant's response acceptable because the applicant confirmed that its calculations for the ferrite contents using the actual alloy compositions are consistent with the guidance in NUREG/CR-4513, Revision 1, as referenced in the GALL Report. Additionally, the calculated ferrite contents indicate that the Class 1 CASS materials are not susceptible to thermal aging embrittlement, consistent with the screening criteria in the GALL Report. The staff's concerns described in RAI 3.1.1.57-1 and followup RAI 3.1.1.57-1a are resolved.

Based on its review, the staff finds that the Class 1 reactor coolant pipe and fittings made of CASS CF8A materials are not susceptible to thermal aging embrittlement based on their casting methods and contents of molybdenum and ferrite, consistent with the GALL Report; therefore, the staff finds the applicant's determination, related to LRA Table 3.1.1, item 3.1.1.57, acceptable.

3.1.2.1.7 Cracking Due to Stress Corrosion Cracking, Irradiation-Assisted Stress Corrosion Cracking, or Fatigue

LRA Table 3.1.1, item 3.1.1.80, addresses CASS RVIs exposed to reactor coolant. SRP-LR, Revision 2, Table 3.1-1, ID 59, recommends GALL Report, Revision 2, AMP XI.M16A, "PWR Vessel Internals," to manage loss of fracture toughness due to thermal aging and neutron irradiation embrittlement for this component group. The applicant stated that this item is not applicable based on EPRI 1016596 (MRP-227, Revision 0).

Specifically, LRA Table 3.1.2-1 indicates that since the RVI CASS upper core support-upper support column base is related to LRA item 3.1.1.80 and no aging effect is applicable to the component, no AMP is proposed for the component. The staff noted that MRP-227 referenced in GALL Report, Revision 2, AMP XI.M16A does not identify the CASS upper core support-upper support column base as a component in the Westinghouse plants that requires aging management for loss of fracture toughness. Therefore, the staff needed clarification regarding the aging management for the CASS upper core support-upper support column base, as described below.

In LRA Section B2.1.35, the "preventive actions" program element of the applicant's PWR Reactor Internals Program states that MRP-227 identifies existing program components whose aging is managed consistent with ASME Code Section XI Table IWB-2500-1, Examination Category B-N-3. In comparison, GALL Report, Revision 2, item IV.B2.RP-382, recommends that cracking and loss of material due to wear of the RVI core support structure, made of stainless steel, nickel alloy, and CASS, should be managed by GALL Report AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD." The staff also noted that Examination Category B-N-3 in Table IWB-2500-1 of the 2004 edition of ASME Code Section XI specifies visual VT-3 examination of the removable core support structures.

However, LRA Table 3.1.2-1 does not clearly indicate whether cracking and loss of material of the CASS upper core support-upper support column base are managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. Therefore, the staff needed clarification as to whether the applicant's aging management method for the CASS upper core support-upper support column base is consistent with GALL Report, Revision 2, item IV.B2.RP-382. By letter dated September 22, 2011, the staff issued RAI 3.1.1.80-1 requesting that the applicant provide justification as to why LRA Table 3.1.2-1 does not identify an AMR item that uses the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program to manage cracking and loss of material of the core support structures, as recommended in the GALL Report.

In its response dated November 21, 2011, the applicant acknowledged that LRA Table 3.1.2-1 does not include AMR items, in which the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program manages cracking and loss of material of the CASS upper support column base and the other core support structure components made of stainless steel, nickel alloy, and CASS materials. The applicant also revised LRA Sections 3.1.2.2.12 and 3.1.2.2.17 and LRA Tables 3.1.1 and 3.1.2-1 to add AMR items that manage cracking and loss of material of stainless steel using the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The applicant further indicated that cracking of the core support structure components is managed under LRA items 3.1.1.30 and 3.1.1.37, and loss of material of the core support structure components is managed under LRA item 3.1.1.63.

In its review, the staff noted that the applicant's addition of these AMR items to manage cracking and loss of material of the RVI components is consistent with the GALL Report. In its revisions to the LRA, the applicant indicated that the PWR Reactor Internals Program is not an applicable AMP for managing cracking of the components listed in the revised LRA Section 3.1.2.2.12, consistent with the GALL Report. The staff further noted that one of these components listed in the revised LRA Section 3.1.2.2.12 is the upper core support-upper core plate, and cracking of the upper core plate is managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program.

However, the staff noted an issue with the applicant's response dated November 21, 2011, as follows. Sections 3.2.2 and 4.1.1 of the staff's SE (June 22, 2011) of MRP-227, Revision 0, address Topical Report Condition 1 for high consequence components. This condition specifies the upper core plate and lower support forging or casting as the expansion components linked to the CRGT assembly lower flange welds, which are the primary components. Section 3.2.2 of the staff's SE also indicates that inspections of these high consequence components shall be triggered by the degradation of the primary component (in this case, CRGT lower flanges). The staff's SE further indicates that the examination method for these additional inspections shall be consistent with the examination method used to detect the degradation of the primary component (in this case, EVT-1). Therefore, the staff needed clarification as to whether the PWR Reactor Internals Program identifies the upper core plate as an expansion component linked to the CRGT lower flange welds to manage loss of material due to wear and cracking due to fatigue, as specified in the staff's SE of MRP-227, Revision 0. In addition, it was not clear whether the applicant's PWR Reactor Internals Program identifies lower internals assembly lower support forging or casting as an expansion component linked to the CRGT lower flange welds to ensure adequate aging management and structural integrity, consistent with the staff's SE of MRP-227, Revision 0.

By letter dated February 8, 2012, the staff issued followup RAI 3.1.1.80-1a requesting that the applicant clarify these items related to the aging management of CRGT lower flange welds and lower internals assembly lower support forging or casting, as described above.

In its response dated February 27, 2012, the applicant stated that it revised LRA Section B2.1.35 and the LRA program basis document to include managing the upper core plate as an expansion component for both loss of material due to wear and cracking due to fatigue, consistent with staff-approved MRP-227-A (December 2011). The applicant also indicated that LRA Section B2.1.35 and the LRA program basis document are revised to include the lower internals assembly lower support forging as an expansion component linked to the CRGT lower flange welds to manage cracking due to fatigue, consistent with staff-approved MRP-227-A. Based on its review, the staff finds that the applicant provided relevant revisions to the LRA consistent with the applicant's responses. In addition, the staff noted that LRA Section B2.1.35 for the PWR Reactor Internals Program is adequately revised to refer to the staff-approved MRP-227-A as guidance for the applicant's program.

Based on its review, the staff finds the applicant's response acceptable because the applicant's responses confirm that the ASME Code Section IX, Examination Category B-N-3, is applied to the RVI core support structure components to adequately manage cracking and loss of material, consistent with the GALL Report, and the applicant's revisions to the LRA include aging management for the upper core plate and lower support forging, ensuring effective detection and management of cracking and loss of material of these components, consistent with staff-approved MRP-227-A. The staff's concerns described in RAI B3.1.1.80-1 and followup RAI B3.1.1.80-1a are resolved.

In its review, the staff noted that LRA Section B2.1.35 for the PWR Reactor Internals Program states that the program manages aging consistent with the inspection guidance for Westinghouse-designated primary components in Table 4-3 of MRP-227 and Westinghouse-designated expansion components in Table 4-6 of MRP-227. The staff also noted that MRP-227 categorizes the RVI components to the following functional groups: primary, expansion, existing programs, and no additional measures.

The staff further noted that MRP-227 also specifies relevant examination methods and coverage for the expansion group components based on the examination findings of the primary group components. In addition, GALL Report, Revision 2, items IV.B2.RP-297, IV.B2.RP-292, and IV.B2.RP-290, and MRP-227 Tables 3-3, 4-3, 4-6, and 5-3 indicate that, in Westinghouse plants, the CRGT assembly lower flanges made of CASS are subject to loss of fracture toughness and are the primary component linked to the following expansion components, which are subject to loss of fracture toughness: (1) lower support assembly lower support column bodies made of CASS, and (2) BMI system BMI column bodies made of stainless steel. However, the staff noted that, in contrast with the GALL Report, LRA Table 3.1.2-1, it does not clearly identify the functional groups and link relationships (for example, primary/expansion relationship) of these components.

By letter dated September 22, 2011, the staff issued RAI 3.1.1.80-2 requesting that the applicant clarify whether the CRGT lower flanges and lower support assembly lower support column bodies are made of CASS and that the applicant describe the functional groups for CRGT assembly lower flanges, lower support column bodies, and BMI column bodies. The staff also requested that the applicant describe the link relationships for these components (such as primary/expansion link) and, if the assigned functional groups or links are not consistent with MRP-227, that the applicant justify why the inconsistency is acceptable to manage loss of fracture toughness of these components. Finally, the applicant was asked to revise LRA Table 3.1.2-1 and other related information in the LRA, consistent with its response.

In its response dated November 21, 2011, the applicant stated that in MRP-227, the CRGT assembly lower flange welds are in the primary functional group with a link to the expansion group components of lower support assembly lower support column bodies made of CASS and BMI system BMI column bodies. The applicant confirmed that since it has an extended core that does not use lower support columns, the MRP-227 components for lower support column bodies are not applicable. The applicant also indicated that the CRGT assembly lower flange welds are subcomponents of the RVI CRGT assembly listed in LRA Table 3.1.2-1. In addition, the applicant indicated that the CRGT lower flanges are fabricated of stainless steel, and cracking is the only aging effect to be managed by MRP-227 for these components. The applicant further indicated that upon detection of cracking in a component susceptible to loss of fracture toughness, the PWR Reactor Internals Program defines an assessment of cracking with limit load or fracture mechanics evaluations or both. In contrast, the staff noted that LRA Table 3.1.2-1 indicates that loss of fracture toughness due to irradiation embrittlement of the CRGT assembly made of stainless steel is managed by the PWR Reactor Internals Program. In addition, Table 3-3 of MRP-227 indicates that the CRGT lower flanges made of CASS are susceptible to cracking due to SCC and fatigue and loss of fracture toughness due to thermal aging embrittlement and irradiation embrittlement. The staff's additional evaluation of these items is described below in connection with followup RAI 3.1.1.80-2a.

In its response regarding BMI column bodies, the applicant also indicated that the BMI column bodies are listed in LRA Table 3.1.2-1 as RVI in-core instrumentation support structures—instrument column (BMI). The applicant further indicated that cracking is the only aging effect to be managed by MRP-227 for the BMI column bodies. In contrast, Table 3-3 of MRP-227 indicates that the BMI column bodies made of Type 304 stainless steel are susceptible to cracking due to fatigue and loss of fracture toughness due to irradiation embrittlement.

In its review of the RAI response, the staff needed clarification regarding whether the CRGT lower flanges are made of CASS. The staff also needed to further clarify whether loss of fracture toughness, in addition to cracking, is considered as an aging effect to be managed by the PWR Reactor Internals Program for these components, consistent with the GALL Report. In addition, the staff needed clarification as to why cracking is the only aging effect to be managed by the PWR Reactor Internals Program for the BMI column bodies, without inclusion of aging management for loss of fracture toughness. By letter dated February 8, 2012, the staff issued RAI 3.1.1.80-2a requesting that the applicant clarify these concerns.

In its response dated February 27, 2012, the applicant confirmed that the CRGT assembly lower flanges are fabricated of non-cast stainless steel and are subject to loss of fracture toughness due to irradiation embrittlement, as addressed under LRA item 3.1.1.22 in LRA Table 3.1.2-1. The applicant also indicated that it concurs that loss of fracture toughness due to irradiation embrittlement of BMI column bodies is identified in the GALL Report, Revision 2, and staff-approved MRP-227-A, Table 4-6. In addition, the applicant provided its revisions to LRA Table 3.1.2-1 in order to add loss of fracture toughness as an aging effect of the BMI column bodies under LRA item 3.1.1.22.

Based on its review, the staff finds the applicant's response acceptable for the following reasons:

- The applicant confirmed that the aging effect of loss of fracture toughness is applicable to the CRGT assembly lower flanges and BMI column bodies and that its RVs do not have a lower support column.
- The applicant's program includes a relevant primary/expansion link relationship between the CRGT lower flanges and BMI column bodies, consistent with the GALL Report.
- The applicant's program includes visual inspections and assessment of cracking, if any, with limit load or fracture mechanics evaluations or both upon detection of cracking in

these components, which is adequate to manage the aging effect, consistent with staff-approved MRP-227-A.

The staff's concerns described in RAI 3.1.1.80-2 and followup RAI 3.1.1.80-2a are resolved.

During its review, the staff noted that the GALL Report, Revision 2, addresses AMR items for the components with no additional measures and the aging effects in the inaccessible locations as described in GALL Report, Revision 2, items IV.B2.RP-267, IV.B2.RP-265, IV.B2.RP-269, and IV.B2.RP-268. In contrast with the GALL Report, LRA Table 3.1.2-1, which addresses the applicant's AMR results for the RVI components, does not clearly address the AMR results for the components with no additional measures and the aging effects in the inaccessible locations.

By letter dated September 22, 2011, the staff issued RAI 3.1.2.1-1 requesting that the applicant provide justification as to why LRA Section 3.1.2-1 does not address AMR items consistent with GALL Report, Revision 2, items IV.B2.RP-265, IV.B2.RP-267, IV.B2.RP-268, and IV.B2.RP-269 for the components with no additional measures and the aging effects in the inaccessible locations. If an aging effect has been identified in the accessible locations of the RVI components, the applicant should provide further evaluation to ensure that the aging effect is adequately managed in the inaccessible locations, as recommended in the GALL Report, Revision 2, and SRP-LR, Revision 2.

In its response dated November 21, 2011, the applicant indicated that the "no additional measures" components are those RVI components for which the aging effects of all eight aging mechanisms are below the screening criteria, as addressed in MRP-227. The applicant also stated that components that were screened out as a result of the failure modes, effects, and criticality analyses, and functionality assessments were added to the "no additional measures" group. The applicant further indicated that the cracking of components in the "no additional measures" group is managed by the Water Chemistry Program and, in some cases, Examination Category B-N-3 inspections of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. In its review, the staff finds that this portion of the applicant's response is acceptable because the applicant clarified that "no additional measures" components were screened out based on the failure modes, effects, and criticality analyses and functionality assessments, consistent with the GALL Report, and the applicant uses the Water Chemistry Program and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, which are adequate to mitigate the environmental effect on aging degradation and to detect and manage cracking and loss of material.

In its response, the applicant also indicated that the minimum examination coverage for primary and expansion inspection categories is 75 percent of the component's total (accessible plus inaccessible) inspection area/volume or, when addressing a set of like components (e.g., bolting), the inspection will examine a minimum sample size of 75 percent of the total population of like components. The applicant further indicated that a technical justification will be required of any minimum coverage requirements below 75 percent of total inspection area/volume or sample size. In addition, the applicant indicated that the PWR Reactor Internals Program is consistent with these conditions regarding the minimum examination coverage addressed in Section 3.3.1 of the staff's SE of MRP-227.

The staff noted that the applicant confirmed that the minimum examination coverage criteria of the applicant's program are consistent with the topical report conditions in the staff's SE of MRP-227. However, the applicant did not indicate whether the applicant performed further evaluation for the aging effect in the inaccessible locations of partially accessible components (including a set of multiple components such as bolts) when an aging effect was detected in the accessible locations of the components, consistent with the GALL Report and SRP-LR. In addition, the staff needed clarification as to whether the applicant's aging management will perform further evaluation to ensure adequate aging management for the inaccessible locations of partially accessible components if an aging effect is identified in the accessible locations of the components. By letter dated September 22, 2011, the staff issued followup RAI 3.1.2.1-1a, requesting clarification as to the applicant's evaluation of an aging effect detected in the accessible locations of the components.

In its response dated February 27, 2012, the applicant stated that ASME Code Section XI, Examination Category B-N-3 examinations of RVI components, conducted during RFO 1RE15 (fall 2009) for Unit 1 and during RFO 2RE14 (spring 2010) for Unit 2, did not identify any conditions that required repair, replacement, or evaluation. The applicant's response, including the revised "operating experience" program element of the PWR Reactor Internals Program, indicates that—based on industry operating experience—the Alloy X-750 guide tube support pins (split pins) were replaced by strain-hardened 316 stainless steel split pins during RFO 1RE12 (spring 2005) for Unit 1 and RFO 2RE11 (fall 2005) for Unit 2 to reduce the susceptibility of SCC in the split pins. The applicant further stated that there were no cracked Alloy X-750 pins discovered during the replacement process, and the LRA and the program basis document were revised to incorporate the operating experience associated with the recent ASME Code inspections and the CRGT support pin replacement.

In addition, the applicant stated that the LRA and the program basis document were revised to specify the component-specific minimum examination coverage criteria, consistent with the staff-approved MRP-227-A (December 2011), Tables 4-3 and 4-6. In addition, if defects are discovered during the examination, the applicant will enter the information into the CAP and evaluate whether the results of the examination ensures that the component (or set of components) will continue to meet its intended function under all licensing-basis conditions of operation until the next scheduled examination. The engineering evaluations that demonstrate the acceptability of the defect are performed consistent with WCAP-17096-NP, "Reactor Internals Acceptance Criteria Methodology and Data Requirements."

Based on its review, the staff finds the applicant's response acceptable for the following reasons:

- The applicant's evaluation of the operating experience and actions, in response to the evaluation, relevantly includes the review of the ASME Code B-N-3 inspection results and replacements of guide tube support pins based on industry operating experience.
- This evaluation was adequately incorporated into the program as part of operating experience review, indicating that currently the program does not have a concern to be further evaluated or resolved.
- The applicant confirmed that any defect discovered during the examination will be evaluated in the CAP to ensure the component (or set of components) will meet its intended functions until the next scheduled examination.
- The engineering evaluation to be performed is consistent with WCAP-17096-NP, which includes justification by evaluation of the aging effects of inaccessible components and provides acceptance criteria and evaluation methodology to determine the component functionality, re-inspection frequencies, repair/replacement/mitigation options, and inspection expansions.

The staff's concerns described in RAI 3.1.2.1-1 and followup RAI 3.1.2.1-1a are resolved.

The staff's evaluation of the PWR Reactor Internals Program is documented in SER Section 3.0.3.3.2. Based on its review of the components associated with items 3.1.1.80 and 3.1.1.22, the staff finds the applicant's proposal to manage loss of fracture toughness for these components acceptable because the PWR Reactor Internals Program includes the adequate screening of RVI components considering susceptibility to aging effects, baseline and subsequent inspections, expansion of inspections based on the inspection results and functional groups, and assessment of cracking with limit load or fracture mechanics evaluations or both upon detection of cracking, which are effective to manage the aging effect consistent with the GALL Report and staff-approved MRP-227-A.

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).

3.1.2.1.8 Cracking Due to Stress Corrosion Cracking and Primary Water Stress Corrosion Cracking

As discussed in SER Section 3.0.3.1.3, the applicant's January 5, 2017, letter (i.e., response to RAI B2.1.8-3) revises LRA Table 3.1.2-4 to indicate that the applicant amended the AMR results for steam generator components based on the guidance in LR-ISG-2016-01. This section documents the staff's evaluation of the revised aging management associated with LRA items 3.1.1.81 and 3.1.1.68, which cite generic note E.

LRA Table 3.1.1, item 3.1.1.81, addresses nickel alloy or nickel alloy clad SG divider plates exposed to reactor coolant, which will be managed for cracking due to PWSCC. In the January 5, 2017, letter, the applicant indicated that the Steam Generator Tube Integrity Program and Water Chemistry Program will be used to manage this aging effect for SG divider plates. As discussed in SER Section 3.0.3.1.3, the divider plates and associated welds are fabricated with Alloy 690 type materials (Alloy 690/52/152 materials), which are resistant to PWSCC. In addition, the applicant clarified that the Steam Generator Tube Integrity Program with enhancement will include periodic visual inspections on SG head internal areas (including divider plates) to identify signs of cracking or loss of material, consistent with LR-ISG-2016-01.

The guidance in LR-ISG-2016-01 indicates that, for units with divider plates fabricated with Alloy 690 type materials, a plant-specific aging management program is not necessary in addition to the existing programs (i.e., GALL Report AMP XI.M2, "Water Chemistry," and AMP XI.M19, "Steam Generators," including periodic visual inspections of SG head internal areas). The staff noted that the applicant's use of the Water Chemistry Program and Steam Generator Integrity Program is consistent with the guidance in LR-ISG-2016-01 for the aging management of cracking in divider plates because these components are made with Alloy 690 type materials (resistant to PWSCC) and the Steam Generator Tube Integrity Program includes periodic visual inspections of SG head internal areas, consistent with LR-ISG-2016-01.

The staff's evaluations of the applicant's Water Chemistry Program and Steam Generator Tube Integrity Program are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.3, respectively. In its review of the components associated with LRA item 3.1.1.81, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Water Chemistry Program and Steam Generator Tube Integrity Program acceptable because

(1) the Water Chemistry Program establishes the plant water chemistry control parameters and their limits to mitigate aging and it identifies the actions required if the parameters exceed the limits; and (2) the Steam Generator Tube Integrity Program includes periodic visual inspections to identify signs of cracking (e.g., rust stains) in these components and other steam generator head internal areas, consistent with the guidance in LR-ISG-2016-01.

In addition, LRA Table 3.1.1, item 3.1.1.68 addresses stainless steel and steel with stainless steel cladding Class 1 components exposed to reactor coolant, which will be managed for cracking due to stress corrosion cracking. In the January 5, 2017, letter, the applicant revised LRA Table 3.1.2-4 to indicate that the Steam Generator Tube Integrity Program will be used in conjunction with ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and the Water Chemistry Program to manage this aging effect for SG primary heads fabricated of carbon steel with stainless steel cladding. The SG primary heads are also called SG heads or channel heads. As previously discussed, the applicant clarified that the Steam Generator Tube Integrity Program with an enhancement will include periodic visual inspections of SG head internal areas in order to identify signs of cracking or loss of material, consistent with LR-ISG-2016-01.

The staff's evaluations of the applicant's ASME Section XI Inservice Inspection, 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, 3.0.3.2.1 and 3.0.3.1.3, respectively. In its review of the components associated with item 3.1.1.68, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, Water Chemistry Program, and Steam Generator Tube Integrity Program acceptable because (1) the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program performs volumetric inspections of steam generator head welds (e.g., tubesheet-to-head welds) to ensure the integrity of the components; (2) the Water Chemistry Program establishes the plant water chemistry control parameters and their limits to mitigate aging and identifies the actions required if the parameters exceed the limits; and (3) the Steam Generator Tube Integrity Program includes periodic visual inspections to identify signs of cracking in steam generator heads, consistent with LR-ISG-2016-01.

The staff concludes that, for LRA items 3.1.1.81 and 3.1.1.68, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.9 Conclusion for AMRs 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 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

LRA Section 3.1.2.2 provides further evaluations of aging management as recommended by the GALL Report for the RCS components. The applicant provided information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to general, pitting, and crevice corrosion
- loss of fracture toughness due to neutron irradiation embrittlement
- cracking due to SCC and IGSCC
- crack growth due to cyclic loading
- loss of fracture toughness due to neutron irradiation embrittlement and void swelling
- cracking due to SCC
- cracking due to cyclic loading
- loss of preload due to stress relaxation
- loss of material due to erosion
- cracking due to flow-induced vibration
- cracking due to SCC and IASCC
- cracking due to PWSCC
- wall thinning due to flow-accelerated corrosion
- changes in dimensions due to void swelling
- cracking due to SCC and PWSCC
- cracking due to SCC, PWSCC, and IASCC

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report and for which the report recommends further evaluation, the staff audited and reviewed the applicant's evaluation. The staff determined whether the applicant adequately addressed the issues for which further evaluation is recommended. The staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.1.2.2. The staff's review of the applicant's further evaluations follows.

3.1.2.2.1 Cumulative Fatigue Damage

LRA Section 3.1.2.2.1 is associated with LRA Table 3.1.1, items 3.1.1.1 through 3.1.1.10, and addresses cumulative fatigue damage in ASME Code Class 1 components and other non-Class 1 components that were analyzed to ASME Code Section III, Class 1 CUF evaluations.

The applicant stated that items 3.1.1.1 through 3.1.1.4 are not applicable to STP, and that items 3.1.1.5 through 3.1.1.10 are TLAAs as defined in 10 CFR 54.3. The applicant also stated that the further evaluation criteria of the SRP-LR are evaluated in accordance with 10 CFR 54.21(c) in LRA Section 4.3.

The staff reviewed LRA Section 3.1.2.2.1 against the criteria in SRP-LR Section 3.1.2.2.1, which state that fatigue is a TLAA, as defined in 10 CFR 54.3, and that TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The staff's review of this TLAA is addressed in SER Section 4.3, "Metal Fatigue Analysis."

The applicant discussed the following items in LRA Table 3.1.1 that are applicable:

- Item 3.1.1.1 is not applicable to STP, as discussed in SER Section 3.1.2.1.1 above.
- Items 3.1.1.2 through 3.1.1.4 are only applicable to BWRs, as discussed in SER Section 3.1.2.1.1 above.
- Items 3.1.1.5 through 3.1.1.10 are associated with cumulative fatigue. The applicant stated that fatigue is a TLAA. This TLAA is addressed separately in LRA Section 4.3.

3.1.2.2.2 Loss of Material Due to General, Pitting, and Crevice Corrosion

Item 1. Table 3.1.1, item 3.1.1.11, is only applicable to BWRs, as discussed in SER Section 3.1.2.1.1 above. Table 3.1.1, item 3.1.1.12, is only applicable to Babcock & Wilcox Co. OTSGs, as discussed in SER Section 3.1.2.1.1 above.

Item 2. Table 3.1.1, item 3.1.1.13, is only applicable to BWRs, as discussed in SER Section 3.1.2.1.1 above.

Item 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.

Item 4. LRA Section 3.1.2.2.2.4 and Table 3.1.1, item 3.1.1.16, address the loss of material due to general, pitting, and crevice corrosion in the SG upper and lower shell and transition cone made of steel and exposed to secondary feedwater and steam.

3.1.2.2.3 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement

Item 1: Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement (TLAA). The staff reviewed LRA Section 3.1.2.2.3.1 and Table 3.1.1, item 3.1.1.17, against the criteria in SRP-LR Section 3.1.2.2.3.1. LRA Section 3.1.2.2.3.1 addresses loss of fracture toughness due to certain aspects of neutron irradiation embrittlement as an aging effect that the applicant will manage through conducting TLAAs, consistent with the SRP-LR. The evaluation of these TLAAs is discussed in LRA Section 4.2. SRP-LR Section 3.1.2.2.3.1 states that, "[c]ertain aspects of neutron irradiation embrittlement are TLAAs as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.2 of this SRP-LR."

As discussed in SER Section 4.2, loss of fracture toughness due to neutron irradiation embrittlement is limited to RPV beltline and extended beltline materials having a neutron fluence greater than $1x10^{17}$ n/cm^2 (with E > 1.0 MeV) at the end of the period of extended operation. SER Section 4.2 accepted the applicant's evaluation of RPV neutron embrittlement in terms of USE, PTS, and P-T limits, which represent a complete set of analytical means for predicting and managing loss of fracture toughness due to neutron irradiation embrittlement. Therefore, the staff concludes that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.1.2.2.3.1. The staff also confirmed that LRA Table 3.1.2-1 identified all GALL Report AMR Table IV.A2 items under this aging mechanism (IV.A2-16 and IV.A2-23).

Item 2: Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement (Surveillance). LRA Section 3.1.2.2.3.2, associated with LRA Table 3.1.1, item 3.1.1.18, addresses steel (with or without stainless steel cladding) RV beltline shell, nozzles, and welds, and safety injection nozzles exposed to neutron irradiation, which will be managed for loss of fracture toughness due to embrittlement by the Reactor Vessel Surveillance Program. The criteria in SRP-LR Section 3.1.2.2.3, item 2, state that loss of fracture toughness due to neutron irradiation embrittlement could occur in PWR RV beltline shell materials, nozzles, and welds when exposed to reactor coolant and neutron flux.

The SRP-LR states that a reactor vessel surveillance program is typically plant-specific depending on the actual composition of limiting materials, the availability of surveillance capsules, and the projected neutron fluence levels for the given RV. The SRP-LR also states that the program should be in accordance with 10 CFR Part 50, Appendix H, that the applicant is required to submit its capsule withdrawal schedule for NRC approval, and that untested capsules held in storage must be maintained for future insertion. The applicant addressed the further evaluation criteria of the SRP-LR by stating that LRA Section B2.1.15, "Reactor Vessel Surveillance," is used to manage the loss of fracture toughness of its RV beltline shell, nozzles, and welds due to neutron fluence.

The staff's evaluation of the applicant's Reactor Vessel Surveillance Program is documented in SER Section 3.0.3.2.12. The staff's evaluation of the applicant's TLAA on neutron embrittlement of RV beltline materials and welds is documented in SER Section 4.2.

Based on the program identified, the staff concludes that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.1.2.2.3, item 2. The staff concludes that the LRA is consistent with the GALL Report and 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.

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 STP, as they are applicable to BWRs only. This information is provided in SER Section 3.1.2.1.1.

3.1.2.2.5 Crack Growth Due to Cyclic Loading

LRA Section 3.1.2.2.5 and Table 3.1.1, item 3.1.1.21, discuss RV underclad cracking. By letter dated March 29, 2012, the applicant amended the LRA to include an analysis of crack growth of underclad flaws in RV forgings due to cyclic loading as a TLAA evaluated in accordance with 10 CFR 54.21(c)(1). The applicant stated that LRA Section 4.7.4 describes the evaluation of this TLAA for the period of extended operation.

SRP-LR Section 3.1.2.2.5 states that crack growth due to cyclic loading could occur in RV shell forgings clad with stainless steel using a high-heat-input welding process. SRP-LR Section 3.1.2.2.5 also states that growth of intergranular separations (underclad cracks) in the heat-affected zone under austenitic stainless steel cladding is a TLAA to be evaluated for the period of extended operation for all SA-508, Class 2 forgings where the cladding was deposited with a high-heat-input welding process, and that the methodology for evaluating the underclad flaw should be consistent with the flaw evaluation procedure and criteria in the ASME Code Section XI, 2004 edition.

The staff reviewed the applicant's basis against the recommended criteria in SRP-LR Section 3.1.2.2.5 for managing underclad cracking in RPV shell or nozzle components that are fabricated from SA-508, Class 2 alloy steel forging materials. The staff noted that the phenomenon of underclad cracking (intergranular separations) is applicable to those welds that were used to adjoin the RPV cladding to those alloy steel RPV shell or nozzle components that are fabricated from SA-508, Class 2 forging materials and where the welding process for depositing the cladding-to-forging component weld involved a high-heat-input weld. The staff confirmed that the applicant's RPV shell base-metal components are fabricated from SA-533 alloy steel plate materials; therefore, the aging management issue raised in SRP-LR Section 3.1.2.2.5 is not applicable to the RPV alloy steel shell components.

The applicant's amended basis was provided as part of its response to the staff's concerns raised in RAI 4.1-3a. This submittal also provided amendments to the LRA Section 3.1.2.2.5, LRA Tables 4.1-1 and 4.1-2, LRA Section 4.7.4, and the new UFSAR supplement summary description for the RV underclad cracking TLAA in LRA Section A.3.6.5. In addition, by letter dated April 17, 2012, the applicant amended LRA Table 3.1.2-1 to include the Table 2 AMR items associated with the management of underclad crack growth in the RV inlet and outlet nozzles, which are the RV nozzles that are fabricated from SA-508 Class 2 alloy steel forging materials. In these AMR items, the applicant credited the associated TLAA with the management of underclad crack growth in these RV nozzle components and their associated clad-to-forging welds.

The staff's evaluation and resolution of RAI 4.1-3a is provided in SER Section 4.1.2.1.2.3. Based on the staff's review of the applicant's response to this RAI, the staff finds that the applicant's amended AMR basis for managing underclad cracking in the steel RV nozzle forgings is acceptable because the AMR basis is consistent with the further evaluation criteria in SRP-LR Section 3.1.2.2.5, "Crack Growth Due to Cyclical Loading." The staff's evaluation of the applicant's TLAA on underclad cracking is provided in SER Section 4.7.4.

The staff concludes 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.

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 Section 3.1.2.2.6 (Revision 1), which recommend no further AMR if the applicant provides a commitment in the UFSAR supplement to:

- 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 in LRA Appendix A, Section A1.35, is consistent with the commitment described in SRP-LR 3.1.2.2.6.

The final recommendations and requirements published in MRP-227-A specify the applicable plant-specific and vendor-specific action items that will be addressed by individual license renewal applicants seeking to use the MRP-227 guidelines as the basis for their PWR RV

Internals AMPs. In LRA Sections A1.35 and B2.1.35, the applicant states that the inspection plans for the Units' RVIs will follow MRP-228, Revision 0. This is consistent with the inspection plan requirement in the staff SE for MRP-227-A.

The staff finds the applicant's proposal to manage aging using the PWR RV Internals AMP is acceptable because the PWR RV Internals AMP is based on the industry programs for investigating and managing aging effects on reactor internals, as established in the MRP-227-A guidelines, and the applicant provided the necessary commitment (Commitment No. 27) in LRA Appendix A, Table A4-1, for addressing the staff's criteria with respect to plant-specific implementation of the MRP-227-A guidelines. The staff's criteria concerning the implementation of MRP-227-A guidelines are established in the staff's SE for MRP-227-A, which addresses conditions, limitations, plant-specific action items, and vendor-specific action items associated with the implementation of MRP-227-A guidelines.

By letter dated June 30, 2015 (ADAMS Accession No. ML15197A029), as supplemented with information in the letter dated December 17, 2015 (ADAMS Accession No. ML16005A093), the applicant amended the LRA to provide the following information for RVI components in the plant design:

(a) updated AMR items to make the AMR items for RVI components consistent with those listed for RVI components in LR-ISG-2011-04

(b) a plant-specific RVIIP for the components that is based on a comparison of the design of RVI components at STP against the generic RVI design assumed for Westinghouse-designed PWRs in the MRP-227-A report

(c) an updated plant-specific AMP for the RVI components that is based on the I&E guidelines for RVI components in the MRP-227-A report

(d) the applicant's bases for resolving applicant/licensee action items (A/LAIs) that pertain to Westinghouse-designed units in the staff's December 16, 2011, SE on the MRP-227-A report.

The staff confirmed that the AMR items are consistent with those listed for Westinghouse-designed RVI components in LR-ISG-2011-04. The staff also confirmed the applicant's plant-specific AMP and RVIIP for the RVI components were appropriately based on the approved augmented I&E guidelines for Westinghouse-designed internals in the MRP-227-A report, and appropriately addressed and resolved those A/LAIs that pertain to these components. The staff evaluation of the applicant's PWR RV Internals AMP (which includes an assessment of the RVIIP and the applicant's responses to the A/LAIs on MRP-227-A) is in SER Section 3.0.3.3.2.

Based on the program identified (as supplemented by the letters of June 30, 2015, and December 17, 2015), the staff concludes that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.1.2.2.6. For those items associated with LRA Section 3.1.2.2.6, 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 function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.7 Cracking Due to Stress Corrosion Cracking

Item 1. LRA Section 3.1.2.2.7.1, which is associated with LRA Table 3.1.1, item 3.1.1.23, addresses cracking due to SCC in stainless steel high-pressure conduits (flux thimble guide tubes to seal table), flux thimble tubes, and RV flange leak detection line exposed to reactor coolant. The LRA stated that for stainless steel high pressure conduits exposed to reactor coolant, the Water Chemistry Program is augmented by ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The LRA also stated that for stainless steel flux thimble tubes exposed to reactor coolant, cracking due to SCC is managed by the Water Chemistry Program.

The staff finds that for the stainless steel high-pressure conduits (flux thimble guide tubes), the applicant meets the further evaluation criteria. The LRA stated that the guide tubes exposed to reactor coolant is managed for cracking due to SCC by the Water Chemistry Program and is augmented by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The staff reviewed LRA Section 3.1.2.2.7.1 against the criteria in SRP-LR Section 3.1.2.2.7, item 1, which state that cracking due to SCC could occur in PWR stainless steel BMI guide tubes exposed to reactor coolant.

The SRP-LR also states that the GALL Report recommends that a plant-specific AMP be evaluated to ensure that this aging effect is adequately managed. BTP RLSB-1 (SRP-LR Appendix A.1) describes the acceptance criteria. SER Sections 3.0.3.2.1 and 3.0.3.1.1 document the staff's evaluation of the applicant's Water Chemistry and ASME Section XI ISI, Subsections IWB, IWC, and IWD programs, respectively. Based on its review of the stainless steel high pressure conduits associated with LRA Table 3.1.1, item 3.1.1.23, the staff finds the applicant's proposal to manage aging using the Water Chemistry and ASME Section XI ISI programs acceptable because the Water Chemistry Program will mitigate the potential development and progress of the aging effect while the ASME Section XI ISI, Subsections IWB, IWC, and IWD Program will 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 3.1.2.2.7, item 1, criterion to manage the aging effects for the stainless steel high-pressure conduits (flux thimble guide tubes).

The GALL Report does not have a specific recommendation for managing SCC of stainless steel flux thimble tubes exposed to reactor coolant. In addition, the staff noted that while there is no operating experience associated with SCC for the applicant's flux thimble tubes, the applicant is conservatively managing for SCC and is crediting its Water Chemistry Program. The staff finds that the Water Chemistry Program can mitigate the potential development and progress of SCC through controlling and limiting the amounts of contaminants that may induce SCC; therefore, the staff finds it acceptable to manage SCC of the flux thimble tubes. The GALL Report recommends a Flux Thimble Tube Inspection AMP to manage the effects of wear. The staff's review of the applicant's Flux Thimble Tube Inspection Program and operating experience related to the flux thimble tubes is documented in SER Section 3.0.3.2.17. Furthermore, as part of its review of this program, the staff confirmed that SCC was not observed for the applicant's stainless steel flux thimbles.

LRA Section 3.1.2.2.7.1 states that the RV flange leak detection line is made of nickel alloy that is normally empty without O-ring leakage. The staff's review of the nickel alloy RV flange leak monitoring tube is documented in SER Section 3.1.2.2.13.

Based on the programs identified, the staff concludes that the applicant's programs meet the further evaluation criteria in SRP-LR Section 3.1.2.2.7, item 1. For the above items that apply to LRA Section 3.1.2.2.7.1, the staff determines that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed for the items discussed above, so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation.

Item 2. LRA Section 3.1.2.2.7.2 is associated with LRA Table 3.1.1, item 3.1.1.24, and addresses the aging effects of cracking due to SCC of Class 1 CASS piping, piping components, and piping elements exposed to reactor coolant, which are being managed by the applicant's Water Chemistry Program and augmented by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The applicant stated that, "although the carbon contents for RCS fittings and piping pieces do not meet the NUREG-0313 criterion of less than 0.035 percent, STP has determined that the molybdenum and ferrite values are below the industry accepted thermal aging embrittlement screening threshold," and it concluded that these CASS reactor coolant piping components are not susceptible to the aging effect of thermal aging embrittlement. The staff determined that a flaw evaluation methodology is not required for these CASS components.

For managing the aging effect of cracking due to SCC of CASS piping components exposed to reactor coolant, the Water Chemistry AMP is augmented by ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD AMP to ensure that adequate inspection methods ensure detection of cracks. The staff's evaluation of the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is documented in SER Section 3.0.3.1.1. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program will be used to confirm the effectiveness of the Water Chemistry Program in managing SCC of the Class 1 CASS piping components in the RCS. The GALL Report, Revision 2, AMP XI.M12 states, "the susceptibility to thermal aging embrittlement of CASS materials is determined in terms of casting method, molybdenum content, and ferrite content." Carbon content is not a consideration. In addition, GALL Report, Revision 2, AMP XI.M12 states that:

> For low-molybdenum content steels (SA-351 Grades CF3, CF3A, CF8, CF8A or other steels with ≤ 0.5 weight percent Mo), only static-cast steels with >20% ferrite are potentially susceptible to thermal embrittlement. Static-cast low-molybdenum steels with ≤20% ferrite and all centrifugal-cast low molybdenum steels are not susceptible. For high-molybdenum content steels (SA-351 Grades CF3M, CF3MA, and CF8M or other steels with 2.0 to 3.0 wt.% Mo), static-cast steels with >14% ferrite and centrifugal-cast steels with >20% ferrite are potentially susceptible to thermal embrittlement. Static-cast high-molybdenum steels with ≤14% ferrite and centrifugal-cast high-molybdenum steels with ≤20% ferrite are not susceptible.

Therefore, for the applicant's CASS materials that do not exceed the threshold limits in GALL Report AMP XI.M12 regarding thermal embrittlement, the applicant is not required to develop flaw evaluation methodologies. 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).

Conclusion. Based on the programs identified above, the staff concludes that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.1.2.2.7. For those items that apply to LRA Section 3.1.2.2.7, 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).

3.1.2.2.8 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 Fracture Toughness Due to Neutron Irradiation Embrittlement

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, Revision 1, which recommends no further AMR if the applicant provides a commitment in the UFSAR supplement to: (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) 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 applicant stated that the loss of preload due to stress relaxation for nickel alloy and stainless steel RVI components will be managed by the PWR Reactor Internals Program, following the guidance of MRP-227-A (Commitment No. 27). The applicant's commitment (Commitment No. 27) in LRA Appendix A, Table A4-1, and information in LRA Appendix A, Section A3, are consistent with the commitment described in SRP-LR 3.1.2.2.9.

By letter dated June 30, 2015 (ADAMS Accession No. ML15197A029), as supplemented with information in the letter dated December 17, 2015 (ADAMS Accession No. ML16005A093), the applicant amended the LRA to provide the following information for RVI components in the plant design:

(a) updated AMR items to make the AMR items for RVI components consistent with those listed for RVI components in LR-ISG-2011-04

(b) a plant-specific RVIIP for the components that is based on a comparison of the design of RVI components at STP against the generic RVI design assumed for Westinghouse-designed PWRs in the MRP-227-A report

(c) an updated plant-specific AMP for the RVI components that is based on the I&E guidelines for RVI components in the MRP-227-A report

(d) the applicant's bases for resolving A/LAIs that pertain to Westinghouse-designed units in the staff's December 16, 2011, SE for the MRP-227-A report

The staff confirmed that the AMR items are consistent with those listed for Westinghouse-designed RVI components in LR-ISG-2011-04. The staff also confirmed the applicant's plant-specific AMP and RVIIP for the RVI components were appropriately based on the approved augmented I&E guidelines for Westinghouse-designed internals in the MRP-227-A report, and appropriately addressed and resolved those A/LAIs that pertain to these components. The staff evaluation of the applicant's PWR RV Internals AMP (which includes an assessment of the RVIIP and the applicant's responses to the A/LAIs on MRP-227-A) is in SER Section 3.0.3.3.2.

Based on the program identified (as supplemented by the letters of June 30, 2015, and December 17, 2015), the staff finds that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.1.2.2.9 and include the appropriate commitment in the UFSAR supplement. For those AMR items associated with LRA Section 3.1.2.2.9, 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 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 addition, the staff finds that the additional actions taken to describe and justify the aging management bases for RVI components at STP have completed the activities committed to in Commitment No. 27. LRA Commitment No. 27 closed.

3.1.2.2.10 Loss of Material Due to Erosion

LRA Section 3.1.2.2.10 states that this item is not applicable as the STP SGs do not have feedwater impingement plates and associated supports.

The staff reviewed the documentation supporting the applicant's AMR evaluation and its UFSAR supplement and confirmed that the installed SGs do not contain steel SG feedwater impingement plates as specified in SRP-LR Section 3.1.2.2.10. Therefore, the staff finds that Table 3.1.1, item 3.1.1.28, and SRP-LR Section 3.1.2.2.10 are not applicable to STP.

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.

3.1.2.2.12 Cracking Due to Stress Corrosion Cracking and Irradiation-Assisted Stress Corrosion Cracking or Fatigue

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 (Revision 1), which note that the existing program relies on control of water chemistry to mitigate cracking due to SCC and irradiation-assisted stress corrosion cracking (IASCC) of PWR stainless steel reactor internals exposed to reactor coolant. SRP-LR 3.1.2.2.12 recommends no further AMR if the applicant provides a commitment in the UFSAR supplement to:

- 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. 27) in LRA Appendix A, Table A4-1, is consistent with the commitment described in SRP-LR 3.1.2.2.12. The staff finds the applicant's proposal acceptable due to the applicant's commitment (Commitment No. 27) to the applicant’s AMP (PWR Reactor Internals Program) and includes the appropriate commitment in the UFSAR supplement.

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 applicant’s Water Chemistry Program is augmented by the commitment described above (Commitment No. 27, PWR Reactor Internals Program). 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.

By letter dated June 30, 2015 (ADAMS Accession No. ML15197A029), as supplemented with information in the letter dated December 17, 2015 (ADAMS Accession No. ML16005A093), the applicant amended the LRA to provide the following information for RVI components in the plant design:

(a) updated AMR items to make the AMR items for RVI components consistent with those listed for RVI components in LR-ISG-2011-04

(b) a plant-specific RVIIP for the components that is based on a comparison of the design of RVI components at STP against the generic RVI design assumed for Westinghouse-designed PWRs in the MRP-227-A report

(c) an updated plant-specific AMP for the RVI components that is based on the I&E guidelines for RVI components in the MRP-227-A report

(d) the applicant’s bases for resolving A/LAIs that pertain to Westinghouse-designed units in the staff’s December 16, 2011, SE for the MRP-227-A report

The staff confirmed that the AMR items are consistent with those listed for Westinghouse-designed RVI components in LR-ISG-2011-04. The staff also confirmed the applicant’s plant-specific AMP and RVIIP for the RVI components were appropriately based on the approved augmented I&E guidelines for Westinghouse-designed internals in the MRP-227-A report, and appropriately addressed and resolved those A/LAIs that pertain to these components. The staff evaluation of the applicant’s PWR RV Internals AMP (which includes an assessment of the RVIIP and the applicant’s responses to the A/LAIs on MRP-227-A) is in SER Section 3.0.3.3.2.

Based on the program identified (as supplemented by the letters of June 30, 2015, and December 17, 2015), the staff concludes that the applicant’s program meets the further evaluation criteria of SRP-LR Section 3.1.2.2.12. For those items that apply to LRA Section 3.1.2.2.12, 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). In addition, the staff finds that the additional actions taken to describe and justify the aging management bases for RVI components at STP have completed the activities committed to in Commitment No. 27. LRA Commitment No. 27 is closed.

3.1.2.2.13 Cracking Due to Primary Water Stress Corrosion Cracking

LRA Section 3.1.2.2.13 is associated with LRA Table 3.1.1, item 3.1.1.31, and addresses nickel alloy nozzles, supports, safe ends, and welds exposed to reactor coolant (internal), which will be managed for cracking due to PWSCC by the Nickel-Alloy Program, the ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD Program, and the Water Chemistry Program. The LRA states that, in addition, aging will be managed through compliance with NRC orders and implementation of bulletins, GLs, and staff-accepted industry guidelines. The criteria in SRP-LR Section 3.1.2.2.13 states that cracking due to PWSCC could occur for components made from 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 but not including RV upper head nozzles and penetrations exposed to reactor coolant. The SRP-LR also states that this degradation may be managed through the use of GALL Report AMPs XI.M1, "ASME Section XI," and XI.M2, "Water Chemistry." This SRP-LR paragraph also recommends no further AMR if the applicant complies with applicable NRC orders and provides a commitment in the UFSAR supplement to implement applicable bulletins and GLs and staff-accepted industry guidelines. The staff notes that the applicant's proposal to manage aging of these components contains all aspects of aging management recommended by the GALL Report. The staff also notes that certain aspects of the program recommended by the GALL Report (e.g., the need to comply with NRC orders) have been superseded by changes to 10 CFR 50.55a and that the updated requirements are addressed in the applicant's Nickel-Alloy Aging Management Program.

The staff's evaluations of the applicant's Nickel-Alloy Program, the ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD Program, and the Water Chemistry Program are documented in SER Sections 3.0.3.3.1, 3.0.3.1.1, and 3.0.3.2.1, respectively. The staff found that these programs are either consistent with the GALL Report or sufficient to manage aging of components within the scope of the AMP. Based on its review of components associated with item 3.1.1.31, the staff finds that the applicant met the further evaluation criteria, and the applicant's proposal to manage aging using the Nickel-Alloy Program, the ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD Program, and the Water Chemistry Program is acceptable because the combined use of these programs meets the requirements established for the inspection of these components in 10 CFR 50.55a and because the GALL Report does not recommend aging management activities in addition to those contained in the regulations.

The staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.1.2.2.13. For those items associated with LRA Section 3.1.1.31, 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).

3.1.2.2.14 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 further evaluation of SG feedrings, which may be susceptible to wall thinning due to flow-accelerated corrosion. The GALL Report references NRC IN 91-19, "Steam Generator Feedwater Distribution Piping Damage," for evidence of flow-accelerated corrosion in SGs 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 stated that feedring wall thinning, as described in IN 91-19, is not applicable to the model of SGs installed at STP, so no action is required, but the Water Chemistry Program and the Steam Generator Tube Integrity Program are credited toward the management of feedring wall thinning due to flow-accelerated corrosion.

STP does not have the specific SG model cited in IN 91-19; therefore, the concerns for the collapse of the feedring are not applicable. As stated in the Steam Generator Tube Integrity Program, the STP SGs were replaced with Westinghouse Delta 94 SGs in 2000 and 2002 for Units 1 and 2, respectively. The GALL Report, under item IV.D1-26, recommends further evaluation of the applicant's AMR results, and references IN 91-19. The staff reviewed IN 91-19 and STP and industry operating experience. Based on this review, the staff concurs that feedring wall thinning, as described in IN 91-19, due to flow-accelerated corrosion of the SG feedring, is a condition not applicable to STP. In addition, since the feedring is composed of carbon steel, the applicant stated it is managing flow-accelerated corrosion of the feedring through the Water Chemistry Program and the Steam Generator Tube Integrity Program. Based on the programs identified, the staff concludes that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.1.2.2.14, and the LRA is consistent with the GALL Report. The staff concludes that the applicant demonstrated that 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).

3.1.2.2.15 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement

The staff reviewed LRA Section 3.1.2.2.15 against the further evaluation criteria in SRP-LR 3.1.2.2.15 (Revision 1), which recommend no further AMR if the applicant provides a commitment in the UFSAR supplement to:

- 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. 27) in LRA Appendix A, Table A4-1 of Section A4, is consistent with the commitment described in SRP-LR 3.1.2.2.15. The staff finds the applicant's proposal acceptable because it meets the further evaluation criteria of SRP-LR Section 3.1.2.2. Commitment No. 27 refers to the applicant's AMP (PWR Reactor Internals Program) and it includes the appropriate commitment in the UFSAR supplement.

By letter dated June 30, 2015 (ADAMS Accession No. ML15197A029), as supplemented with information in the letter dated December 17, 2015 (ADAMS Accession No. ML16005A093), the applicant amended the LRA to provide the following information for RVI components in the plant design:

(a) updated AMR items to make the AMR items for RVI components consistent with those listed for RVI components in LR-ISG-2011-04

(b) a plant-specific RVIIP for the components that is based on a comparison of the design of RVI components at STP against the generic RVI design assumed for Westinghouse-designed PWRs in the MRP-227-A report

(c) an updated plant-specific AMP for the RVI components that is based on the I&E guidelines for RVI components in the MRP-227-A report

(d) the applicant's bases for resolving A/LAIs that pertain to Westinghouse-designed units in the staff's December 16, 2011, SE for the MRP-227-A report.

The staff confirmed that the AMR items are consistent with those listed for Westinghouse-designed RVI components in LR-ISG-2011-04. The staff also confirmed the applicant's plant-specific AMP and RVIIP for the RVI components were appropriately based on the approved augmented I&E guidelines for Westinghouse-designed internals in the MRP-227-A report, and appropriately addressed and resolved those A/LAIs that pertain to these components. The staff evaluation of the applicant's PWR RV Internals AMP (which includes an assessment of the RVIIP and the applicant's responses to the A/LAIs on MRP-227-A) is given in SER Section 3.0.3.3.2.

Based on the program identified (as supplemented in the letters of June 30, 2015, and December 17, 2015), the staff concludes that the applicant's basis meets the further evaluation criteria of SRP-LR Section 3.1.2.2.15. For those items associated with LRA Section 3.1.2.2.15, 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 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 addition, the staff finds that the additional actions taken to describe and justify the aging management bases for RVI components at STP have completed the activities committed to in Commitment No. 27. LRA Commitment No. 27 is closed.

3.1.2.2.16 Cracking Due to Stress Corrosion Cracking and Primary Water Stress Corrosion Cracking

<u>Item 1</u>. LRA Section 3.1.2.2.16.1, associated with LRA Table 3.1.1, item 3.1.1.34, addresses the stainless steel control rod drive mechanism (CRDM) head penetrations, exit thermocouple penetration housing, internal disconnect device housing, and RV water level indication system (RVWLIS) upper probe housing exposed to reactor coolant, which will be managed for cracking due to SCC by the Water Chemistry Program and ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The criteria in SRP-LR Table 3.1-1, ID 34, also state that cracking due to SCC could occur in the stainless steel reactor CRD head penetration pressure housings. The GALL Report recommends GALL Report AMPs XI.M2, "Water Chemistry," and XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," to manage the aging effect.

In its review related to the stainless steel CRDM penetration pressure housing, the staff noted that LRA Table 3.1.2-1 indicates that the applicant's aging management method described in LRA Section 3.1.2.2.16.1 and LRA item 3.1.1.34 applies to the following components:

- RV CRDM housing
- RV exit thermocouple penetration housing
- RV internal disconnect device housing

- RVWLIS upper probe housing
- RV CRDM head penetrations (flange and plug)
- RV CRDM head penetrations (thermal sleeve), which are made of stainless steel

The staff also noted that LRA Section B2.1.1 describes the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, which is credited by the applicant to manage cracking due to SCC of the stainless steel components addressed in LRA item 3.1.1.34. The staff further noted that ASME Code Section XI (2004 edition), Table IWB-2500-1, Examination Category B-O, item B14.20, specifies volumetric or surface examination of the welds in CRD housings. However, the staff noted that the LRA did not state what inspection methods and examination categories will be used in the applicant's program to manage cracking due to SCC for the stainless components described in LRA Table 3.1.2-1.

By letter dated September 22, 2011, the staff issued RAI 3.1.2.2.16.1-1 requesting that the applicant describe the inspection methods and examination categories that the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program will use to manage cracking due to SCC of the stainless steel components described in LRA Table 3.1.2-1 and provide justification as to why the inspection methods are adequate to manage cracking due to SCC of these components. The staff also requested that the applicant describe how the RV CRDM penetration flange and plug are installed (e.g., either as welded or threaded connection to the penetration flange) to clarify whether the plug is attached directly to the RV head as a result of the repair of the CRDM penetration nozzles. The staff further requested that the applicant revise LRA Section 3.1.2.2.16.1 to include the RV CRDM housing in the LRA section, consistent with LRA item 3.1.1.34.

In its response, dated November 21, 2011, the applicant clarified that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program provides volumetric or surface examinations of the RV exit thermocouple penetration housing, RV internal disconnect device housing, RVWLIS upper probe housing, RV CRDM head penetrations (flange and plug), and RV CRDM head penetrations (thermal sleeve). The applicant also stated that ASME Code Section XI, IWB-2500-1, Examination Category B-O, provides volumetric or surface examinations of the RV head penetration housings, and ASME Code Case N-729-1 requires that all nozzles in the head must be inspected using volumetric and surface examinations every 10-year inservice inspection interval. The applicant also stated that this ASME Code Case also requires bare metal visual examinations of the Unit 1 and Unit 2 RV heads to detect leakage, and these ASME Code examinations are industry-accepted methods that have proven to be effective for identifying SCC in the RV head penetrations. The applicant also stated that the CRDM head penetration plugs in LRA Table 3.1.2-1 refer to the previous CRDM latch housings capped with a canopy seal-welded threaded plug and that the replacement heads do not have capped latch housings. The applicant also provided a revision to LRA Section 3.1.2.16.1 to change "CRDM head penetrations" to "CRDM penetrations and housings."

Based on its review, the staff finds the applicant's response acceptable because the applicant identified the ASME Code inspections using periodic visual, surface, and volumetric examinations that will adequately manage cracking due to SCC of these components described in LRA Section 3.1.2-1. The applicant also clarified that the replacement heads do not have a capped latch housing. The applicant also amended LRA Section 3.1.2.2.16.1 to include RV CRDM housings consistent with the GALL Report. The staff's concerns described in RAI 3.1.2.2.16.1-1 are resolved.

In addition, LRA Section 3.1.2.2.16.1 addresses cracking due to PWSCC of SG nickel alloy tube-to-tubesheet welds exposed to reactor coolant. GALL Report, Revision 2, item IV.D1.RP-385, recommends GALL Report AMP XI.M2, "Water Chemistry," and a plant-specific program to manage cracking due to PWSCC of SG tube-to-tubesheet welds made of nickel alloy, where the plant-specific program confirms the effectiveness of the Water Chemistry Program to ensure that cracking does not occur. The criteria in SRP-LR, Revision 2, Section 3.1.2.2.11, item 2, state that cracking due to PWSCC could occur in SG nickel alloy tube-to-tubesheet welds exposed to reactor coolant.

In its review related to SG nickel alloy tube-to-tubesheet welds, the staff noted that LRA Section 3.1.2.2.16.1 and LRA item 3.1.1.35 state that the applicant has recirculating SGs, not OTSGs; therefore, further evaluation of Section 3.1.2.2.16.1 for the OTSG components is not applicable to the applicant. Accordingly, the applicant's AMR items for the SG components, which are described in LRA Table 3.1.2-4, do not address how the applicant manages the cracking due to PWSCC of SG tube-to-tubesheet welds exposed to reactor coolant.

However, SRP-LR, Revision 2, also states that unless the NRC has approved a redefinition of the pressure boundary such that the tube-to-tubesheet weld is no longer included, the effectiveness of the Primary Water Chemistry Program should be confirmed to ensure that cracking does not occur. Therefore, the staff needed additional information and clarification concerning how the applicant will manage cracking due to PWSCC of SG nickel alloy tube-to-tubesheet welds.

By letter dated September 22, 2011, the staff issued RAI 3.1.2.2.16.1-2 requesting that the applicant describe the materials that were used for the fabrication of the SG tubes, tubesheet cladding and tube-to-tubesheet welds and explain how cracking due to PWSCC of the SG tube-to-tubesheet welds will be managed for the period of extended operation. The staff also requested that if the applicant proposes a one-time inspection to manage cracking due to PWSCC of the components, the applicant describe the operating experience in terms of the occurrence of PWSCC of the tube-to-tubesheet welds. The staff further requested that if the operating experience indicates that these components have experienced cracking due to PWSCC, the applicant justify why the proposed use of a one-time inspection rather than periodic inspections is adequate to manage the aging effect.

In its response dated November 21, 2011, the applicant stated that the tube plate of the SG is low-alloy steel that is clad with weld-deposited nickel chromium iron alloys (UNS N06052 and W86152) and that the SG tubes are fabricated of Alloy 690 (UNS N06690). The applicant also stated that industry operating experience has not shown PWSCC in these PWSCC-resistant materials (Alloy 690/52/152 materials). The applicant further stated that the Water Chemistry Program is thereby considered adequate to manage PWSCC, and a plant-specific program is not necessary. In addition, the applicant stated that its commitment to review industry operating experience (Commitment No. 29) will ensure that if PWSCC becomes an issue in Alloy 690/52/152 materials, it will be managed appropriately.

Based on its review, the staff finds the applicant's response acceptable for the following reasons:

- The applicant's SG tubes and tubesheet cladding use PWSCC-resistant materials (Alloy 690/52/152 materials).
- The applicant's Water Chemistry Program is adequate to manage cracking due to PWSCC of these components, consistent with SRP-LR, Revision 2, Section 3.1.2.2.11.
- The applicant confirmed the ongoing review of the industry operating experience to ensure that if PWSCC becomes an issue in Alloy 690/52/152 materials, it will be managed appropriately.

The staff's concerns described in RAI 3.1.2.2.16.1-2 are resolved.

As discussed in SER Section 3.0.3.1.3, the applicant's January 5, 2017, letter in response to RAI B2.1.8-3 describes revised AMR results to be consistent with LR-ISG-2016-01. The applicant indicated that, in conjunction with the Water Chemistry Program, the Steam Generator Tube Integrity Program is used to manage cracking due to PWSCC for SG tube-to-tubesheet welds. As previously discussed, the applicant also identified an enhancement to the program to implement periodic visual inspections of SG head internal areas (including the tubesheet primary side) to identify signs for cracking or loss of material. Specifically, the applicant revised the AMR item in LRA Table 3.1.2-4 that manages cracking for the tube-to-tubesheet welds.

LR-ISG-2016-01 provides updated guidance on further evaluation acceptance criteria regarding aging management of cracking for SG tube-to-tubesheet welds. LR-ISG-2016-01 states that for units with SG tubes and tubesheet cladding using Alloy 690 type material (which is resistant to PWSCC), a plant-specific AMP is not necessary in addition to the existing programs (i.e., Water Chemistry and Steam Generator Programs). The staff notes that, since the applicant's tube-to-tubesheet welds are made with Alloy 690 type material (Alloy 690/52/152 materials), a plant-specific program in addition to the existing programs is not necessary in accordance with the guidance in LR-ISG-2016-01. Therefore, the staff finds the applicant's proposed aging management of cracking for the SG tube-to-tubesheet welds is acceptable.

The staff's evaluations of the applicant's Water Chemistry Program and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.1, respectively. The staff finds that the applicant meets the further evaluation criteria. Further, the staff finds the applicant's proposal to manage aging using the Water Chemistry Program and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is acceptable to manage cracking due to SCC of the CRDM penetration pressure housing and the other related components described in LRA item 3.1.1.34 because the Water Chemistry Program limits the concentrations of chemical species known to cause SCC and controls the dissolved oxygen level to minimize the environmental effect on SCC, and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program performs visual, surface and volumetric inspections, which are adequate to detect and manage cracking due to SCC of the stainless steel CRDM penetration pressure housings and the other components addressed in LRA item 3.1.1.34.

In addition, the staff's evaluations of the applicant's Water Chemistry Program and Steam Generator Tube Integrity Program are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.3, respectively. The staff finds that the applicant met the further evaluation criteria (as revised in LR-ISG-2016-01). Additionally, the applicant's proposal to manage aging using the Water

Chemistry Program and Steam Generator Tube Integrity Program is acceptable to manage cracking due to PWSCC of the SG tube-to-tubesheet welds because (1) the Water Chemistry Program limits the concentrations of chemical species known to cause PWSCC and controls the dissolved oxygen level to minimize the environmental effect on PWSCC, and (2) the Steam Generator Tube Integrity Program, which includes periodic visual inspections, is sufficient to manage cracking due to PWSCC of the SG nickel alloy tube-to-tubesheet welds made of the PWSCC-resistant materials (Alloy 690/52/152 materials), consistent with the acceptance criteria in SRP-LR, Revision 2, Section 3.1.2.2.11 (as revised in LR-ISG-2016-01).

Based on the programs identified, the staff concludes that the applicant's programs meet the further evaluation criteria in SRP-LR, Revision 1, Section 3.1.2.2.16, and SRP-LR, Revision 2, Section 3.1.2.2.11 (as revised in LR-ISG-2016-01). For those items that apply to LRA Section 3.1.2.2.16.1, the staff determines that the LRA is consistent with the GALL Report (as revised in LR-ISG-2016-01) 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).

Item 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 being managed for cracking due to SCC and PWSCC by the Water Chemistry and the One-Time Inspection AMPs. LRA Table 3.1.2-3 states that the STP pressurizer spray heads are made of stainless steel. The criteria in SRP-LR Section 3.1.2.2.16.2 states, in part, that cracking due to SCC could occur on stainless steel pressurizer spray heads in the pressurizer. The GALL Report, Revision 2, item IV.C2.RP-41, recommends managing stainless steel pressurizer spray heads for SCC using the GALL Report AMPs XI.M2, "Water Chemistry," and XI.M32, "One-Time Inspection."

The staff's evaluations of the Water Chemistry and One-Time Inspection programs are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.4, respectively. In its review of item 3.1.1.36, the staff finds that the applicant's proposal in LRA Section 3.1.2.2.16.2 to manage aging for the pressurizer spray heads is acceptable and consistent with the GALL Report. The staff also finds that the commitment mentioned in SRP-LR Section 3.1.2.2.16.2 is not required since the STP spray heads are not composed of nickel alloy material.

On the basis of its review, the staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.1.2.2.16.2. For those items associated with LRA Section 3.1.1.16.2, 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).

3.1.2.2.17 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 against criteria in SRP-LR Section 3.1.2.2.17 (Revision 1), which notes that the existing program relies on control of water chemistry to mitigate cracking due to SCC, PWSCC, and IASCC of PWR stainless steel and nickel alloy reactor internals exposed to reactor coolant. SRP-LR Section 3.1.2.2.17 recommends no further AMR if the applicant provides a commitment in the UFSAR supplement to: (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) 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. 27) in LRA Appendix A, Table A4-1 is consistent with the commitment described in SRP-LR Section 3.1.2.2.17. The staff finds the applicant's proposal acceptable because the discussion of the AMR item refers to the applicant's AMP (PWR Reactor 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 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 RV internal components exposed to reactor coolant.

By letter dated June 30, 2015 (ADAMS Accession No. ML15197A029), as supplemented with information in the letter dated December 17, 2015 (ADAMS Accession No. ML16005A093), the applicant amended the LRA to provide the following information for RVI components in the plant design:

(a) updated AMR items to make the AMR items for RVI components consistent with those listed for RVI components in LR-ISG-2011-04

(b) a plant-specific RVIIP for the components based on a comparison of the design of RVI components at STP against the generic RVI design assumed for Westinghouse-designed PWRs in the MRP-227-A report

(c) an updated plant-specific AMP for the RVI components that is based on the I&E guidelines for RVI components in the MRP-227-A report

(d) the applicant's bases for resolving A/LAIs that pertain to Westinghouse-designed units in the staff's December 16, 2011, SE for the MRP-227-A report

The staff confirmed that the AMR items are consistent with those listed for Westinghouse-designed RVI components in LR-ISG-2011-04. The staff also confirmed the applicant's plant-specific AMP and RVIIP for the RVI components were appropriately based on the approved augmented I&E guidelines for Westinghouse-designed internals in the MRP-227-A report, and appropriately addressed and resolved those A/LAIs that pertain to these components. The staff evaluation of the applicant's PWR RV Internals AMP (which includes an assessment of the RVIIP and the applicant's responses to the A/LAIs on MRP-227-A) is in SER Section 3.0.3.3.2.

Based on the programs identified (as supplemented in the letters of June 30, 2015, and December 17, 2015), the staff concludes that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.1.2.2.17. 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 functions will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). In addition, the staff finds that the additional actions taken to describe and justify the aging management bases for RVI components at STP have completed the activities committed to in Commitment No. 27. LRA Commitment No. 27 is closed.

3.1.2.2.18 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's QA Program.

3.1.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.1.2-1 through 3.1.2-4, the staff reviewed additional details of AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.1.2-1 through 3.1.2-4, the applicant indicated, via notes F through J, that the combination of component type, material, environment, and AERM does not correspond to 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 whether the applicant had 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 Vessel, Internals, and Reactor Coolant System—Summary of Aging Management Evaluation—Reactor Vessel and Internals—LRA Table 3.1.2-1

In LRA Tables 3.1.2-1, 3.1.2-3, and 3.1.2-4, the applicant stated that for nickel alloy components—including penetration nozzles and welds, safe ends and welds, and monitoring tubes—exposed to air with borated water leakage, there is no aging effect, and no AMP is proposed. The AMR items cite generic note G. In 9 of the 11 items, plant-specific note 2 applies. In the remaining items, no plant-specific note is indicated. Plant-specific note 2 states that "NUREG-1801 does not address the aging effect of nickel alloys in borated water leakage. Nickel alloys subject to an air with borated water leakage environment are similar to stainless steel in a borated water leakage environment and do not experience aging effects due to borated water leakage."

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment. In conducting this review, the staff considered all aging effects that are contained in the GALL Report for nickel alloys irrespective of the environment and all aging effects associated with the environment "air with borated water leakage" irrespective of the material. For nickel alloys in any environment, the GALL Report lists the following aging effects: cracking due to SCC, fatigue, denting, and loss of material. For the environment "air with borated water leakage," the GALL Report lists only loss of material. For these nickel alloy components exposed to borated water leakage, the aging effect cracking due to SCC need not be considered because neither the GALL Report nor operating experience have revealed any instances of cracking of nickel alloy components exposed to air with borated water leakage. This absence of cracking is likely a function of the environmental oxygen content, the component temperature, and the boric acid concentration. The issue of fatigue of these components will be addressed as a TLAA elsewhere in this SER as appropriate. Due to the location of these components, denting is not a credible aging effect. Loss of material is also not a credible aging effect for these components exposed to this environment based on Revision 2 to the GALL Report. This revision specifically contains an item, which indicates that no aging effect is applicable, and no AMP is recommended when nickel alloy components are exposed to air with borated water leakage. This change to the GALL Report is based on data contained in EPRI report 1000975, "Boric Acid Corrosion Guidebook," Revision 1. This report contains data (page 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."

On the basis of its review, the staff concludes that, for nickel alloy components exposed to air with borated water leakage, which are listed in LRA Table 3.1.2-1, 3.1.2-3, and 3.1.2-4, the applicant appropriately evaluated the material and environment combinations, and no aging management is necessary to provide reasonable assurance that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.3.2 Reactor Vessel, Internals, and Reactor Coolant System—Summary of Aging Management Evaluation—Reactor Coolant System—LRA Table 3.1.2-2

Nickel Alloy Closure Bolting Exposed to Borated Water Leakage. As amended by letter dated November 30, 2011, "Annual Update to the LRA Letter," LRA Table 3.1.2-2 states that nickel alloy closure bolting exposed to borated water leakage will be managed for cracking and loss of preload by the Bolting Integrity Program. The AMR items cite generic note F.

The staff noted that this material and environment combination is identified in the GALL Report, Revision 2, which addresses nickel alloy bolting exposed to any environment and recommends GALL Report AMP XI.M18, "Bolting Integrity," to manage loss of preload; however, the applicant has identified cracking as an additional aging effect. The applicant addressed the GALL Report identified aging effects for this component, material, and environment combination in AMR items in LRA Table 3.1.2-2.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.5. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because it includes bolting assembly and maintenance controls—such as application of appropriate gasket alignment, torque, lubricants, and preload—and inspects bolted connections to ensure detection of leakage occurs before the leakage becomes excessive. In addition, the applicant's Bolting Integrity Program invokes the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, which provides the requirements for inservice inspection of ASME Code Class 1 safety-related pressure-retaining bolting, which is capable of detecting cracking.

Calcium Silicate and Fiberglass Insulation Exposed to Plant Indoor Air (External). As amended by letter dated June 3, 2014, in LRA Table 3.1.2-2, the applicant stated that calcium silicate and fiberglass insulation exposed to plant indoor air (external) will be managed for reduced thermal insulation resistance due to moisture intrusion by the External Surfaces Monitoring Program.

The staff noted that although the applicant cited generic note H, LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," provides AMR items to address this material, environment, and aging effect combination. GALL Report AMR item S-403 states that reduced thermal insulation resistance due to moisture intrusion is managed for calcium silicate and fiberglass insulation exposed to plant indoor air (external), by GALL Report AMP XI.M36.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.16. The staff finds the applicant's proposal to manage aging using the External Surfaces Monitoring Program acceptable because periodic visual inspections of the insulation jacketing will be conducted to verify that the insulation is water-tight.

3.1.2.3.3 Reactor Vessel, Internals, and Reactor Coolant System—Summary of Aging Management Evaluation—Pressurizer—LRA Table 3.1.2-3

In LRA Table 3.1.2-3, the applicant stated that for nickel alloy Pressurizer safe ends exposed to air with borated water leakage—there is no aging effect, and no AMP is proposed. This issue is evaluated in SER Section 3.1.2.3.1.

The staff reviewed LRA Table 3.1.2-3, which summarizes the results of AMR evaluations for the pressurizer system component groups.

The staff's review did not find any items indicating plant-specific notes F through 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 associated with notes A through E is documented in SER Section 3.1.2.1.

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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.3.4 Reactor Vessel, Internals, and Reactor Coolant System—Summary of Aging Management Evaluation—Steam Generators—LRA Table 3.1.2-4

In LRA Table 3.1.2-4 the applicant stated that for nickel alloy SG Primary —including nozzles and safe ends exposed to air with borated water leakage—there is no aging effect, and no AMP is proposed. This issue is evaluated in SER Section 3.1.2.3.1.

The staff reviewed LRA Table 3.1.2-4, which summarizes the results of AMR evaluations for the SG system component groups.

The staff's review did not find any items indicating plant-specific notes F through 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 associated with notes A through E is documented in SER Section 3.1.2.1.

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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.3.5 Loss of Material in Steam Generator Head Components

As discussed in SER Section 3.0.3.1.3, the applicant's January 5, 2017, letter (i.e., response to RAI B2.1.8-3) revises LRA Table 3.1.2-4 to indicate that the applicant amended the AMR results for steam generator components based on the guidance in LR-ISG-2016-01. This section documents the staff's evaluation of the revised aging management for loss of material in SG heads, tubesheets, tube-to-tubesheet welds, and divider plates exposed to reactor coolant. SG heads are also called SG primary heads or channel heads. The applicant indicated that the SG heads and tubesheets are fabricated of carbon steel with stainless steel cladding and carbon steel with nickel alloy, respectively. The applicant also indicated that the SG tube-to-tubesheet welds and divider plates are fabricated of nickel alloys.

In LRA Table 3.1.2-4, the applicant added AMR items to manage loss of material for the SG components discussed above by using the Steam Generator Tube Integrity Program and Water Chemistry Program. As previously discussed, the applicant indicated that the Steam Generator Tube Integrity Program with an enhancement will include periodic visual inspections of SG head internal areas (including the primary side of the SG heads and tubesheets) to identify signs of cracking or loss of material, consistent with LR-ISG-2016-01. These AMR items cite generic note H.

In its review, the staff noted that the guidance in LR-ISG-2016-01 recommends that the Water Chemistry Program and Steam Generator Program, including periodic visual inspections of SG head internal areas, should be used to manage loss of material due to boric acid corrosion for SG heads (primary side) and tubesheets that are fabricated of steel with stainless steel or nickel alloy cladding and that are exposed to reactor coolant. The periodic visual inspections are intended to identify signs of loss of material or cracking (e.g., rust stains).

In its review, the staff finds that the applicant's use of the Water Chemistry Program and Steam Generator Tube Integrity Program is consistent with LR-ISG-2016-01 and, therefore, acceptable to manage loss of material for the SG heads and tubesheets. The staff also finds the applicant's use of the Water Chemistry Program and Steam Generator Tube Integrity Program to be acceptable to manage loss of material for the SG divider plates and tube-to-tubesheet welds because (1) the applicant's Water Chemistry Program establishes the plant water chemistry control parameters and their limits to mitigate aging and it identifies the actions required if the parameters exceed the limits; and (2) the Steam Generator Tube Integrity Program includes periodic visual inspections to identify signs of loss of material in these components, consistent with the guidance in LR-ISG-2016-01.

3.1.3 Conclusion

The staff concludes that the applicant provided sufficient information to demonstrate that the effects of aging for the RV and internals, RCS, pressurizer, and SG components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will remain consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2 Aging Management of Engineered Safety Features

This section of the SER documents the staff's review of the applicant's AMR results for the ESF components and component groups of the following systems:

- containment spray system
- integrated leak rate test system
- residual heat removal system
- safety injection system

3.2.1 Summary of Technical Information in the Application

LRA Section 3.2 provides AMR results for the ESF components and component groups. LRA Table 3.2.1, "Summary of Aging Management Evaluations in Chapter V of NUREG-1801 for Engineered Safety Features," provides a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for ESF components and component groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included issue reports and discussions with appropriate site personnel to identify AERMs. The applicant's operating experience review included industry sources, 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 ESF components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff conducted an onsite audit to examine the applicant's AMPs and related documentation to confirm the applicant's claims that certain AMPs were consistent with the corresponding GALL Report AMPs. The staff did not repeat its review of the matters described in the GALL Report. The staff's evaluations of the AMPs are documented in SER Section 3.0.3.

The staff reviewed the AMRs to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did confirm that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. Details of the staff's evaluation are discussed in SER Sections 3.2.2.1 and 3.2.2.2.

The staff also reviewed the AMRs not consistent with or not addressed in the GALL Report. The review evaluated whether all plausible aging effects were identified and whether the aging effects listed were appropriate for the combination of materials and environments specified. Details of the staff's evaluation are discussed in SER Section 3.2.2.3.

For components 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 confirm 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 ESF System Components in the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel and stainless steel piping, piping components, and piping elements in the ECCS (3.2.1.1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes, TLAA	TLAA	Fatigue is a TLAA (see SER Section 3.2.2.2.1)
Steel with stainless steel cladding pump casing exposed to treated borated water (3.2.1.2)	Loss of material due to cladding breach	A plant-specific AMP is to be evaluated. Reference NRC IN 94-63, "Boric Acid Corrosion of Charging Pump Casings Caused by Cladding Cracks."	Yes, verify that plant-specific program addresses cladding breach.	Not applicable to STP	Not applicable to STP (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, detection of aging effects is to be evaluated.	Water Chemistry Program and One-Time Inspection Program	Consistent with the GALL Report (see SER Section 3.2.2.2.3, item 1)
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, plant-specific	Not applicable to STP	Not applicable to STP (see SER Section 3.2.2.2.3, item 2)
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	BWR Only	Not applicable to PWRs, therefore not applicable to STP (see SER Section 3.2.2.1.1)
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, detection of aging effects is to be evaluated.	Not applicable to STP	Not applicable to STP (see SER Section 3.2.2.2.3, item 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
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, plant-specific	Not applicable to STP	Not applicable to STP (see SER Section 3.2.2.2.3, item 5)
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, plant-specific	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.2.2.2.3, item 6)
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, detection of aging effects is to be evaluated.	Lubricating Oil Analysis Program and One-Time Inspection Program	Consistent with the GALL Report (see SER Section 3.2.2.2.4, item 1)
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, detection of aging effects is to be evaluated.	Water Chemistry Program and One-Time Inspection Program	Consistent with the GALL Report (see SER Section 3.2.2.2.4, item 2)
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	BWR only	Not applicable to PWRs, therefore not applicable to STP (see SER Section 3.2.2.1.1)
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, plant-specific	Not applicable to STP	Not applicable to STP (see SER Section 3.2.2.2.6)

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
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	BWR only	Not applicable to PWRs, therefore not applicable to STP (see SER Section 3.2.2.1.1)
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	BWR only	Not applicable to PWRs, therefore not applicable to STP (see SER Section 3.2.2.1.1)
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, detection of aging effects is to be evaluated.	Not applicable to STP	Not applicable to STP (see SER Section 3.2.2.2.8, item 2)
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, detection of aging effects is to be evaluated.	Not applicable to STP	Not applicable to STP (see SER Section 3.2.2.2.8, item 3)
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 MIC	Buried Piping and Tanks Surveillance or Buried Piping and Tanks Inspection	Yes	BWR only	Not applicable to STP (see SER Section 3.2.2.2.9)
Stainless steel piping, piping components, and piping elements exposed to treated water > 60 °C (140 °F) (3.2.1.18)	Cracking due to SCC and IGSCC	BWR SCC and Water Chemistry	No	BWR only	Not applicable to PWRs, therefore not applicable to STP (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	BWR only	Not applicable to PWRs, therefore not applicable to STP (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
CASS piping, piping components, and piping elements exposed to treated water (borated or unborated) > 250 °C (482 °F) (3.2.1.20)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS	No	BWR only	Not applicable to PWRs, therefore not applicable to STP (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 to STP	Not applicable to STP (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 to STP	Not applicable to STP (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 Program	Consistent with the GALL Report
Steel closure bolting exposed to air-indoor uncontrolled (external) (3.2.1.24)	Loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	No	Bolting Integrity Program	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water > 60 °C (140 °F) (3.2.1.25)	Cracking due to SCC	Closed-Cycle Cooling Water System	No	Closed-Cycle Cooling Water System Program	Consistent with the 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	Not applicable to STP	Not applicable to STP (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
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 Program	Consistent with the 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 Program	Consistent with the 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 Program	Consistent with the GALL Report
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 Program	Consistent with the 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 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 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 the 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 to STP	Not applicable to STP (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	BWR only	Not applicable to PWRs (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 MIC and fouling	Open-Cycle Cooling Water System	No	Not applicable to STP	Not applicable to STP (see SER Section 3.2.2.1.1)
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	Not applicable to STP	Not applicable to STP (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 to STP	Not applicable to STP (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	Not applicable to STP	Not applicable to STP (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 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	Not applicable to STP	Not applicable to STP (see SER Section 3.2.2.1.1)
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 to STP	Not applicable to STP (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	Not applicable to STP	Not applicable to STP (see SER Section 3.2.2.1.1)
Gray cast iron piping, piping components, piping elements exposed to closed-cycle cooling water (3.2.1.42)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Not applicable to STP	Not applicable to STP (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 to STP	Not applicable to STP (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 to STP	Not applicable to STP (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 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 encapsulation components exposed to air with borated water leakage (internal) (3.2.1.46)	Loss of material due to general, pitting, crevice, and boric acid corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable to STP	Not applicable to STP (see SER Section 3.2.2.1.1)
CASS piping, piping components, and piping elements exposed to treated borated water > 250 °C (482 °F) (3.2.1.47)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS	No	Not applicable to STP	Not applicable to STP (see SER Section 3.2.2.1.1)
Stainless steel or stainless steel clad steel piping, piping components, piping elements, and tanks (including safety injection tanks and accumulators) exposed to treated borated water > 60 °C (140 °F) (3.2.1.48)	Cracking due to SCC	Water Chemistry	No	Water Chemistry Program and One-Time Inspection Program	Consistent with the GALL Report (see SER Section 3.2.2.1.2)
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 Program and One-Time Inspection Program	Consistent with the GALL Report (see SER Section 3.2.2.1.3)
Aluminum piping, piping components, and piping elements exposed to air-indoor uncontrolled (internal/external) (3.2.1.50)	None	None	Not applicable	None	Consistent with the GALL Report (see SER Section 3.2.2.1.4)
Galvanized steel ducting exposed to air-indoor controlled (external) (3.2.1.51)	None	None	Not applicable	Not applicable to STP	Not applicable to STP (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
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	Not applicable	Not applicable to STP	Not applicable to STP (see SER Section 3.2.2.1.1)
Stainless steel, copper alloy, and Ni-alloy piping, piping components, and piping elements exposed to air-indoor uncontrolled (external) (3.2.1.53)	None	None	Not applicable	None	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to air-indoor controlled (external) (3.2.1.54)	None	None	Not applicable	Not applicable to STP	Not applicable to STP (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	Not applicable	Not applicable to STP	Not applicable to STP (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	Not applicable	None	Consistent with the 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	Not applicable	None	Consistent with the GALL Report

SER Section 3.2.2.1 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. SER Section 3.2.2.2 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. SER Section 3.2.2.3 discusses the staff's review of AMR results for components that the applicant stated are not consistent with or not addressed in the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the ESF components is documented in SER Section 3.0.3.

3.2.2.1 AMR Results That Are Consistent with the GALL Report

LRA Section 3.2.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the ESF systems and components:

- ASME Section XI Inservice Inspection (Subsections IWB, IWC, and IWD)
- Bolting Integrity
- Boric Acid Corrosion
- Closed-Cycle Cooling Water System
- External Surfaces Monitoring Program
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- One-Time Inspection
- Water Chemistry

LRA Tables 3.2.2-1 through 3.2.2-4 summarize the results of AMRs for the ESF components and indicate AMRs claimed to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant has claimed consistency and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine whether the plant-specific components in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR item describing how the information in the tables aligns with the information in the GALL Report. The staff reviewed those AMRs with notes A through E, which indicate how the AMR was consistent with the GALL Report.

Note A indicates that the AMR 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 confirm 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 confirm consistency with the GALL Report and confirmed that it had reviewed and accepted the identified exceptions to the GALL Report AMPs. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR 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 confirm 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 confirm 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 had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR 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 confirm consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

The staff reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, it did confirm that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs.

The staff reviewed the LRA to confirm that the applicant did the following:

- provided a brief description of the system, components, materials, and environments
- stated that the applicable aging effects were reviewed and evaluated in the GALL Report
- identified those aging effects for the ESF components that are subject to an AMR

On the basis of its audit and review, the staff determines that, for AMRs not requiring further evaluation as identified in LRA Table 3.2.1, the applicant's references to the GALL Report are acceptable, and no further staff review is required.

3.2.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.2.1, items 3.2.1.5, 3.2.1.11, 3.2.1.13, 3.2.1.14, 3.2.1.17 through 3.2.1.20, and 3.2.1.34, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable because the associated items are only applicable to BWRs. In the applicant's 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 noted that STP is a PWR with a dry ambient containment. Based on its review, the staff finds the applicant's statement is acceptable and these items are not applicable to STP.

LRA Table 3.2.1, item 3.2.1.21, is associated with managing high-strength steel closure bolting exposed to air with steam or water leakage for cracking due to cyclic loading and SCC. The applicant stated that this item is not applicable to STP because STP does not have any in-scope high-strength steel closure bolting in the ESF systems, and the applicable items in the GALL Report were not used. The staff reviewed LRA Sections 2.3.2 and 3.2, and the UFSAR, and finds that the applicant's statement is acceptable and this item is not applicable to STP.

LRA Table 3.2.1, item 3.2.1.22, addresses steel closure bolting exposed to air with steam or water leakage. The GALL Report recommends GALL Report AMP XI.M18, "Bolting Integrity," to manage loss of material due to general corrosion for this component group. The applicant stated that this item is not applicable because it has used item 3.2.1.23 to manage aging of these items. The staff evaluated the applicant's claim and finds it acceptable because the GALL Report environments of air with steam or water leakage and air-indoor uncontrolled are included within the applicant's definition of plant indoor air, and LRA Table 3.2.1, item 3.2.1.23, age manages steel closure bolting exposed to plant indoor air and was consistently used in the AMR Table 2s to manage loss of material due to general corrosion.

LRA Table 3.2.1, item 3.2.1.26, is associated with managing steel piping, piping components, and piping elements exposed to CCCW for loss of material due to general, pitting, and crevice corrosion. The applicant stated that this item is not applicable to STP because STP does not have any in-scope steel piping, piping components, or piping elements exposed to CCCW in the ESF systems, and the applicable items in the GALL Report were not used. The staff reviewed LRA Sections 2.3.2 and 3.2, and the UFSAR, and finds that the applicant's claim is acceptable. Therefore, the staff concluded this item is not applicable to STP.

LRA Table 3.2.1, item 3.2.1.33, is associated with managing steel encapsulation components exposed to air-indoor uncontrolled (internal) for loss of material due to general, pitting, and crevice corrosion. The applicant stated that this item is not applicable to STP because STP does not have any in-scope steel encapsulation components in the ESF systems and that the applicable items in the GALL Report were not used. The staff reviewed LRA Sections 2.3.2 and 3.2, and the UFSAR, and finds that the applicant's statement is acceptable. Therefore, the staff concluded this item is not applicable to STP.

LRA Table 3.2.1, item 3.2.1.35, addresses steel containment isolation piping and components with internal surfaces exposed to raw water. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to manage loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion (MIC) and fouling for this component group. The applicant stated that this item is not applicable because the containment isolation components were evaluated in the systems in which the components were found to have the function of containment integrity. The staff evaluated the applicant's claim, and it was not clear to the staff where the stainless steel containment isolation piping and components exposed to raw water are identified in the LRA. In addition, it was not clear how the aging of containment isolation piping and components exposed to water will be managed. By letter dated September 22, 2011, the staff issued RAI 3.2.1.15-1 requesting that the applicant provide additional information showing what systems in the containment isolation piping and components were found to have the function of containment integrity. Additionally, the staff requested that the applicant provide additional information on what AMP will be used to manage aging of these components exposed to raw water and provide technical information that supports the adequacy of this program.

In its response dated November 21, 2011, the applicant stated that the only containment penetrations with an internal environment of raw water are associated with the fire protection system and the radioactive vents and drains system. The applicant further stated that the containment isolation components in the fire protection system are managed by the Fire Water System Program, which requires volumetric or internal inspections of the components. The applicant also stated that the containment penetration contained in the radioactive vents and drains system are managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The applicant stated that the program requires visual inspections of the internal surfaces of a sample of the components. The staff finds the applicant's claim, that this item is not applicable, acceptable because the applicant is managing loss of material for containment penetrations exposed to raw water by either the Fire Water System Program or Internal Surfaces in Miscellaneous Piping and Ducting Components Program, which include visual inspections capable of detecting loss of material in these components exposed to raw water. The staff's concern described in RAI 3.2.1.15-1 is resolved.

LRA Table 3.2.1, item 3.2.1.36, is associated with managing steel heat exchanger components exposed to raw water for loss of material due to general, pitting, crevice, galvanic, and MIC and fouling. The applicant stated that this item is not applicable to STP because STP does not have any in-scope steel heat exchanger components exposed to raw water in the ESF systems, and the applicable items in the GALL Report were not used. The staff reviewed LRA Sections 2.3.2 and 3.2, and the UFSAR, and finds that the applicant's statement is acceptable. Therefore, the staff concluded this item is not applicable to STP.

LRA Table 3.2.1, item 3.2.1.37, is associated with managing stainless steel piping, piping components, and piping elements exposed to raw water for loss of material due to pitting, crevice, and MIC. The applicant stated that this item is not applicable to STP because STP does not have any in-scope stainless steel components exposed to raw water in the ECCS, and the applicable items in the GALL Report were not used. The staff reviewed LRA Sections 2.3.2 and 3.2, and the UFSAR, and finds that the applicant's statement is acceptable. Therefore, the staff concluded this item is not applicable to STP.

LRA Table 3.2.1, item 3.2.1.38, is associated with managing stainless steel containment isolation piping and components with internal surfaces exposed to raw water for loss of material due to pitting and crevice corrosion, MIC, and fouling. The applicant stated that this item is not applicable to STP because STP does not have any in-scope stainless steel components exposed to raw water in the ESF systems, and the applicable items in the GALL Report were not used. The staff reviewed LRA Sections 2.3.2 and 3.2, and the UFSAR, and finds that the applicant's statement is acceptable. Therefore, the staff concluded this item is not applicable to STP.

LRA Table 3.2.1, item 3.2.1.39, is associated with managing stainless steel heat exchanger components exposed to raw water for loss of material due to pitting and crevice corrosion, MIC, and fouling. The applicant stated that this item is not applicable to STP because STP does not have any in-scope stainless steel heat exchanger components exposed to raw water in the ESF systems, and the applicable items in the GALL Report were not used. The staff reviewed LRA Sections 2.3.2 and 3.2, and the UFSAR, and finds that the applicant's statement is acceptable. Therefore, the staff concluded this item is not applicable to STP.

LRA Table 3.2.1, item 3.2.1.40, is associated with managing steel and stainless steel heat exchanger tubes (serviced by open-cycle cooling water) exposed to raw water for reduction of heat transfer due to fouling. The applicant stated that this item is not applicable to STP because STP does not have any in-scope steel and stainless steel heat exchanger tubes (serviced by open-cycle cooling water) exposed to raw water in the ESF systems, and the applicable items in the GALL Report were not used. The staff reviewed LRA Sections 2.3.2 and 3.2, and the UFSAR, and finds that the applicant's statement is acceptable. Therefore, the staff concluded this item is not applicable to STP.

LRA Table 3.2.1, item 3.2.1.41, is associated with managing copper alloy (greater than 15 percent Zn) piping, piping components, piping elements, and heat exchanger components exposed to CCCW for loss of material due to selective leaching. The applicant stated that this item is not applicable to STP because STP does not have any in-scope copper alloy (greater than 15 percent Zn) piping, piping components, piping elements, or heat exchanger components exposed to CCCW in the ESF systems, and the applicable items in the GALL Report were not used. The staff reviewed LRA Sections 2.3.2 and 3.2, and the UFSAR, and finds that the applicant's statement is acceptable. Therefore, the staff concluded this item is not applicable to STP.

LRA Table 3.2.1, item 3.2.1.42, is associated with managing gray cast iron piping, piping components, and piping elements exposed to CCCW for loss of material due to selective leaching. The applicant stated that this item is not applicable to STP because STP does not have any in-scope gray cast iron piping, piping components, or piping elements exposed to CCCW in the ECCS, and the applicable items in the GALL Report were not used. The staff reviewed LRA Sections 2.3.2 and 3.2, and the UFSAR, and finds that the applicant's statement is acceptable. Therefore, the staff concluded this item is not applicable to STP.

LRA Table 3.2.1, item 3.2.1.43, is associated with managing gray cast iron piping, piping components, and piping elements exposed to soil for loss of material due to selective leaching. The applicant stated that this item is not applicable to STP because STP does not have any in-scope gray cast iron piping, piping components, or piping elements exposed to soil in the ECCS, and the applicable items in the GALL Report were not used. The staff reviewed LRA Sections 2.3.2 and 3.2, and the UFSAR, and finds that the applicant's statement is acceptable. Therefore, the staff concluded this item is not applicable to STP.

LRA Table 3.2.1, item 3.2.1.44, is associated with managing gray cast iron motor cooler exposed to treated water for loss of material due to selective leaching. The applicant stated that this item is not applicable to STP because STP does not have any in-scope gray cast iron motor coolers exposed to treated water in the ESF systems, and the applicable items in the GALL Report were not used. The staff reviewed LRA Sections 2.3.2 and 3.2, and the UFSAR, and finds that the applicant's statement is acceptable. Therefore, the staff concluded this item is not applicable to STP.

LRA Table 3.2.1, item 3.2.1.46, is associated with managing steel encapsulation components exposed to air with borated water leakage (internal) for loss of material due to general, pitting, crevice, and boric acid corrosion. The applicant stated that this item is not applicable to STP because STP does not have any in-scope steel encapsulation components in the ESF systems, and the applicable items in the GALL Report were not used. The staff reviewed LRA Sections 2.3.2 and 3.2, and the UFSAR, and finds that the applicant's statement is acceptable. Therefore, the staff concluded this item is not applicable to STP.

LRA Table 3.2.1, item 3.2.1.47, is associated with managing CASS piping, piping components, and piping elements exposed to treated borated water greater than 250 °C (482 °F) for loss of fracture toughness due to thermal aging embrittlement. The applicant stated that this item is not applicable to STP because STP does not have any in-scope CASS piping, piping components, or piping elements exposed to treated borated water greater than 250 °C in the ECCS, and the applicable items in the GALL Report were not used. The staff reviewed LRA Sections 2.3.2 and 3.2, and the UFSAR, and finds that the applicant's statement is acceptable. Therefore, the staff concluded this item is not applicable to STP.

LRA Table 3.2.1, item 3.2.1.51, addresses galvanized steel ducting exposed to air-indoor controlled (external) and states that there are no aging effects or aging mechanisms and that no AMPs will be credited for this material and environment combination. The applicant stated that this item is not applicable to STP because STP does not have any in-scope galvanized steel ducting exposed to air-indoor controlled (external) in the ESF systems, and the applicable items in the GALL Report were not used. The staff reviewed LRA Sections 2.3.2 and 3.2, and the UFSAR, and finds that the applicant's statement is acceptable. Therefore, the staff concluded this item is not applicable to STP.

LRA Table 3.2.1, item 3.2.1.52, addresses glass piping elements exposed to air-indoor uncontrolled (external), lubricating oil, raw water, treated water, or treated borated water and states that there are no aging effects or aging mechanisms, and no AMPs will be credited for this material and environment combination. The applicant stated that this item is not applicable to STP because STP does not have any in-scope glass piping elements in the ESF systems, and the applicable items in the GALL Report were not used. The staff reviewed LRA Sections 2.3.2 and 3.2, and the UFSAR, and finds that the applicant's statement is acceptable. Therefore, the staff concluded this item is not applicable to STP.

LRA Table 3.2.1, item 3.2.1.54, addresses steel piping, piping components, and piping elements exposed to air-indoor controlled (external). The GALL Report recommends that there is no AERM for this component group. The applicant stated that this item is not applicable because its plant has no in-scope steel piping, piping components, and piping elements exposed to air-indoor controlled (external) in the ESF system. The staff reviewed LRA Table 3.0-1 and noted that the applicant includes air-indoor controlled (external), as defined in the GALL Report, within a more general environment called "plant indoor air (when used as external)." The staff also noted that plant indoor air (external) includes potential for condensation. The staff further noted that the applicant includes AMR evaluations for steel piping, valves, flanges, and heat exchangers exposed to plant indoor air (external) in LRA Table 3.2.1, item 3.2.1.31, and credits the External Surfaces Monitoring Program to manage loss of material due to general corrosion. The staff evaluated the applicant's claim that item 3.2.1.54 is not applicable and concluded this item is not applicable to STP because the applicant chose to manage steel piping components in a manner consistent with a more corrosive environment, plant indoor air (external), and the visual inspections in the External Surfaces Monitoring Program are capable of detecting general corrosion prior to loss of intended function.

LRA Table 3.2.1, item 3.2.1.55, addresses steel and stainless steel piping, piping components, and piping elements in concrete and states that there are no aging effects or mechanisms, and no AMPs will be credited for this material and environment combination. The applicant stated that this item is not applicable to STP because STP does not have any in-scope steel and stainless steel piping, piping components, or piping elements in concrete, and the applicable items in the GALL Report were not used. The staff reviewed LRA Sections 2.3.2 and 3.2, and the UFSAR, and did not identify any steel and stainless steel piping, piping components, or piping elements in concrete that were in-scope of license renewal. Therefore, the staff concluded that this item is not applicable to STP.

3.2.2.1.2 Cracking Due to Stress Corrosion Cracking

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 (including safety injection tanks/accumulators) exposed to treated borated water greater than 60 °C (140 °F), which will be managed for cracking due to SCC. For the AMR item that cites generic note E, the LRA credits the Water Chemistry Program to manage the aging effect. The applicant also credits the One-Time Inspection Program that will confirm the effectiveness of the Water Chemistry Program for adequate aging management of cracking. The GALL Report recommends GALL Report AMP XI.M2, "Water Chemistry," to ensure that the aging effect is adequately managed.

GALL Report AMP XI.M2 recommends using water chemistry control to manage aging by limiting the concentrations of chemical species known to cause SCC and controlling dissolved oxygen levels to minimize the environmental effect on SCC. The staff noted that the Water Chemistry Program manages the aging of stainless steel or stainless steel clad steel piping, piping components, piping elements, and tanks through the use of water chemistry control, and the One-Time Inspection Program provides confirmation of the effectiveness of the Water Chemistry Program for adequate aging management of cracking due to SCC.

The staff's evaluations of the applicant's Water Chemistry Program and One-Time Inspection Program are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.4, respectively. In its review of components associated with item 3.2.1.48, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Water Chemistry Program and One-Time Inspection Program acceptable because the Water Chemistry Program limits the concentrations of chemical species known to cause SCC and controls the dissolved oxygen level to minimize the environmental effect on SCC, and the One-Time Inspection Program includes a one-time inspection of selected components to confirm the effectiveness of the Water Chemistry Program so that it is ensured to adequately manage cracking due to SCC of these components.

The staff concludes that for LRA item 3.2.1.48, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.1.3 Loss of Material Due to Pitting and Crevice Corrosion

LRA Table 3.2.1, item 3.2.1.49, addresses stainless steel piping, piping components, piping elements, and tanks exposed to treated borated water, which will be managed for loss of material due to pitting and crevice corrosion. For the AMR items that cite generic note E, the LRA credits the Water Chemistry and One-Time Inspection programs to manage the aging effect for stainless steel piping, piping components, piping elements, and tanks. The GALL Report recommends GALL Report AMP XI.M2, "Water Chemistry," to ensure that these aging effects are adequately managed.

GALL Report AMP XI.M2 recommends using water chemistry control to minimize contaminant concentration to manage aging. The staff noted that the Water Chemistry and One-Time Inspection programs propose to manage the aging of stainless steel piping, piping components, piping elements, and tanks through the use of water chemistry controls to minimize contaminant concentrations along with a one-time visual inspection to confirm the effectiveness of the Water Chemistry Program.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection programs are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.4, respectively. Based on its review of components associated with item 3.2.1.49, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Water Chemistry and One-Time Inspection programs acceptable because the Water Chemistry Program establishes the plant water chemistry control parameters and their limits to mitigate aging and identifies the actions required if the parameters exceed the limits, and the One-Time Inspection Program prescribes appropriate visual, volumetric, or other inspection techniques capable of detecting pitting and crevice corrosion prior to loss of intended function to confirm the effectiveness of the water chemistry controls.

The staff concludes that for LRA item 3.2.1.49, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.1.4 Aluminum Piping, Piping Components, and Piping Elements Exposed to Air-Indoor Uncontrolled (Internal/External)

LRA Table 3.2.1, item 3.2.1.50, addresses aluminum piping, piping components, and piping elements exposed to air-indoor uncontrolled, which have no identified AERMs. During its review of components associated with item 3.2.1.50, for which the applicant cited generic note A, the staff noted an AMR item in LRA Table 3.3.2-17 for carbon steel valves exposed to fuel oil that appears to be incorrectly associated with item 3.2.1.50. The GALL Report, Revision 2, items VII.H1.AP-105 and VII.H2.AP-105, state that carbon steel piping, piping components, piping elements, and tanks exposed to fuel oil are susceptible to loss of material and recommend GALL Report AMP XI.M30, "Fuel Oil Chemistry," and XI.M32, "One-Time Inspection," to manage the aging effect. By letter dated September 22, 2011, the staff issued RAI 3.2.1.50-1 requesting that the applicant review the AMR item for carbon steel valves exposed to fuel oil in Table 3.3.2-17 that is associated with item 3.2.1.50 and either correct errors associated with the item or explain why the item has no AERMs.

In its response dated November 21, 2011, the applicant revised the AMR item in LRA Table 3.3.2-17 for carbon steel valves exposed to fuel oil to specify that this component will be managed for loss of material by the Fuel Oil Chemistry and One-Time Inspection programs. The applicant also revised the AMR item to associate it with LRA Table 3.3.1, item 3.3.1.20, which is for steel piping, piping components, piping elements, and tanks exposed to fuel oil that will be managed for loss of material due to general, pitting, crevice, and MIC and fouling by the Fuel Oil Chemistry and One-Time Inspection programs. The staff finds the applicant's response acceptable because the revised AMR result is consistent with the recommendations in the GALL Report for aging management of carbon steel piping components exposed to a fuel oil environment. The staff's concern described in RAI 3.2.1.50-1 is resolved.

The staff concludes that for LRA item 3.2.1.50, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation Is Recommended

LRA Section 3.2.2.2 provides further evaluations of aging management, as recommended by the GALL Report for the ESF components. The applicant provided information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to cladding 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

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report and for which further evaluation is recommended, the staff audited and reviewed the applicant's evaluations to determine whether they adequately address those issues. In addition, the staff reviewed the applicant's further evaluations against the criteria in SRP-LR Section 3.2.2.2. The staff's review of the applicant's further evaluations follows.

3.2.2.2.1 Cumulative Fatigue Damage

LRA Section 3.2.2.2.1 states that fatigue is a TLAA, as defined in 10 CFR 54.3, "Definitions." 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.

3.2.2.2.2 Loss of Material Due to Cladding Breach

LRA Section 3.2.2.2.2 is associated with LRA Table 3.2.1, item 3.2.1.2, and addresses loss of material due to cladding breach in steel with stainless steel cladding pump casings exposed to treated borated water. The applicant stated that this item is not applicable because the ECCS does not contain steel with stainless steel cladding pump casings exposed to treated borated water. The staff reviewed LRA Sections 2.3.2 and 3.2, and the UFSAR, and finds that no in-scope pump casings comprising steel with stainless steel cladding exposed to treated borated water are present in the ESF systems. Therefore, the staff finds that this aging affect related to component ground "steel with stainless steel cladding pump casing exposed to treated borated water" is not applicable to STP.

3.2.2.2.3 Loss of Material Due to Pitting and Crevice Corrosion

Item 1. LRA Section 3.2.2.2.3.1, associated with LRA Table 3.2.1, item 3.2.1.3, addresses internal surfaces of stainless steel containment isolation piping and components exposed to demineralized water, which will be 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 existing AMP relies on monitoring and control of water chemistry to mitigate degradation. The SRP-LR further states that the effectiveness of the chemistry control program should be confirmed to ensure that corrosion does not occur. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Water Chemistry and One-Time Inspection programs will manage loss of material in components exposed to demineralized water. The applicant also stated that the One-Time Inspection Program includes inspections of selected components at susceptible locations where contaminants could accumulate.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection programs are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.4. In its review of components associated with item 3.2.1.3, 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 establishes the plant water chemistry control parameters and their limits to mitigate the potential for aging and identifies the actions required if the parameters exceed the limits, and the One-Time Inspection

Program prescribes appropriate visual, volumetric, or other inspection techniques capable of detecting pitting and crevice corrosion in order to confirm the effectiveness of the water chemistry controls.

Based on the programs identified, the staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.2.2.2.3, item 1. For those items associated with LRA Section 3.2.2.2.3.1, 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).

Item 2. LRA Section 3.2.2.2.3.2, associated with LRA Table 3.2.1, item 3.2.1.4, addresses stainless steel piping, piping components, and piping elements exposed to soil. The applicant stated that this item is not applicable because the ECCS does not contain any in-scope stainless steel piping, piping components, and piping elements exposed to soil. The staff reviewed LRA Sections 2.3.2 and 3.2, and the applicant's UFSAR, and finds that no in-scope stainless steel piping, piping components, and piping elements exposed to soil are present in the ESF systems.

Item 3. LRA Table 3.2-1, item 3.2.1.5, is applicable to BWRs only. This information is provided in SER Section 3.2.2.1.1.

Item 4. LRA Section 3.2.2.2.3.4, associated with LRA Table 3.2.1, item 3.2.1.6, addresses loss of material due to pitting and crevice corrosion in stainless steel and copper-alloy piping, piping components, and piping elements exposed to lubricating oil. The applicant stated that this item is not applicable because STP has no in-scope stainless steel and copper-alloy piping, piping components, and piping elements exposed to lubricating oil in the ECCS. The staff reviewed LRA Sections 2.3.2, 3.1, and the UFSAR, and finds that no in-scope loss of material due to pitting and crevice corrosion in stainless steel and copper-alloy piping, piping components, and piping elements exposed to lubricating oil are present in the system.

Item 5. LRA Section 3.2.2.2.3.5, associated with LRA Table 3.2.1, item 3.2.1.7, addresses partially encased stainless steel tanks with breached moisture barrier exposed to raw water. The applicant stated that this item is not applicable because the ECCS does not contain any in-scope stainless steel tanks with a moisture barrier configuration exposed to raw water. The staff reviewed LRA Sections 2.3.2 and 3.2, and the applicant's UFSAR, and finds that that no in-scope stainless steel tanks with moisture barrier exposed to raw water are present in the ESF systems.

Item 6. LRA Section 3.2.2.2.3.6, associated with LRA Table 3.2.1, item 3.2.1.8, addresses stainless steel piping, piping components, piping elements, and tanks exposed to internal condensation, which will be managed for loss of material due to pitting and crevice corrosion by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The criteria in SRP-LR Section 3.2.2.2.3, item 6, states that loss of material due to pitting and crevice corrosion could occur for stainless steel piping, piping components, piping elements, and tanks exposed to internal condensation. The SRP-LR also states that a plant-specific AMP should be used to ensure that the aging effect is 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 will manage loss of material in the internal condensation environment.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.18. In its review of components associated with item 3.2.1.8, 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 because the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program will perform periodic visual inspections that are capable of detecting loss of material due to pitting and crevice corrosion, which is consistent with the updated guidance in the GALL Report, Revision 2.

Based on the programs identified, the staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.2.2.2.3, item 6. For those items associated with LRA Section 3.2.2.2.3.6, 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).

3.2.2.2.4 Reduction of Heat Transfer Due to Fouling

Item 1. LRA Section 3.2.2.2.4, item 1, associated with LRA Table 3.2.1, item 3.2.1.9, addresses steel, stainless steel, and copper heat exchanger tubes exposed to lubricating oil, which will be 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 could 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 that 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 confirm the program's effectiveness. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Lubricating Oil Analysis and the One-Time Inspection programs manage loss of heat transfer due to fouling for copper alloy components exposed to lubricating oil. The applicant further stated that the one-time inspection includes selected components at susceptible locations where contaminants could accumulate (e.g., stagnant flow locations).

The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection programs are documented in SER Sections 3.0.3.2.19 and 3.0.3.1.4, respectively. In its review of components associated with item 3.2.1.9, the staff finds that the applicant meets the further evaluation criteria and that the applicant's proposal to manage aging using the specified AMPs is 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 confirm the effectiveness of the Lubricating Oil Analysis Program to manage this aging effect.

Based on the programs identified, the staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.2.2.2.4, item 1. For those items associated with LRA Section 3.2.2.2.4, item 1, 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).

Item 2. LRA Section 3.2.2.2.4, item 2, associated with LRA Table 3.2.1, item 3.2.1.10, addresses stainless steel heat exchanger tubes exposed to treated water. The applicant stated that this item is not applicable because there are no in-scope stainless steel heat exchanger tubes exposed to treated water in the containment spray system. To confirm this, the staff reviewed LRA Sections 2.3.2 and 3.2 for the ESF systems and noted that, although this was true for the containment spray system, the RHR heat exchangers and RHR pump seal water coolers contain stainless steel heat exchanger tubes exposed to treated borated water. The staff considers certain aging effects of treated borated water to be comparable to treated water, including reduction of heat transfer, and, as such, the staff considers item 3.2.1.10 to be applicable to both treated water and treated borated water.

The staff also noted that the LRA cites generic note H for these components to indicate that this aging effect is not in the GALL Report for this component, material, and environment combination. For these components, the LRA specifies the Water Chemistry and One-Time Inspection programs as the applicable AMPs, which are consistent with the further evaluation criteria in SRP-LR Section 3.2.2.2.4, item 2. The staff finds the specified AMPs acceptable and discussed these components in more detail in SER Section 3.2.2.3.3.

3.2.2.2.5 Hardening and Loss of Strength Due to Elastomer Degradation

LRA Table 3.2.1, item 3.2.1.11, is for BWRs only; therefore, it is not applicable to STP. This information is provided in SER Section 3.2.2.1.1.

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 safety injection pumps' minimum flow orifices exposed to treated borated water. The criteria in SRP-LR Section 3.2.2.2.6 state 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 safety injection pumps are not used for normal charging and that the associated line in the GALL Report is not applicable.

The staff noted in the GALL Report that only the HPSI pumps' minimum flow recirculation orifices are associated with item 3.2.1.12 and that loss of material due to erosion is identified as a concern when there is extended use of the HPSI pumps for normal charging, including use of ECCS minimum flow recirculation piping. The staff reviewed descriptions of the ECCS and the chemical and volume control system (CVCS) in the applicant's UFSAR and on the license renewal boundary drawings. The staff noted that the applicant's safety injection system includes both high-head and low-head safety injection pumps with minimum flow recirculation orifices. The staff further noted that the applicant's UFSAR states that both the high-head and the low-head safety injection pumps are normally in standby mode and that centrifugal pumps in the CVCS normally provide charging flow to the RCS. The staff finds it acceptable that the applicant determined that item 3.2.1.12 and SRP-LR Section 3.2.2.2.6 are not applicable for the following reasons:

- RCS charging flow is normally provided by centrifugal pumps in the CVCS.
- The high-head and low-head safety injection pumps are normally in standby and do not pump borated water through their minimum flow recirculation orifices during standby mode.
- With no flow going through the safety injection pumps' minimum flow recirculation orifices when those pumps are in standby, there is no mechanical interaction with moving fluid to cause erosion in their minimum flow recirculation orifices during the periods between scheduled ECCS pump surveillance testing.

3.2.2.2.7 Loss of Material Due to General Corrosion and Fouling

LRA Table 3.2.1, item 3.2.1.13, is for BWRs only; therefore, it is not applicable to STP. This information is provided in SER Section 3.2.2.1.1.

3.2.2.2.8 Loss of Material Due to General, Pitting, and Crevice Corrosion

Item 1. LRA Table 3.2-1, item 3.2.1.14, is applicable to BWRs only; therefore, it is not applicable to STP. This information is provided in SER Section 3.2.2.1.1.

Item 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 the 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 the containment isolation components were evaluated in the systems in which the components were found to have the function of containment integrity. The staff reviewed all steel piping, piping components, and piping elements exposed to treated water in the LRA and noted that the applicant chose to manage these components with LRA Table 3.4-1, item 3.4.1.4, which manages loss of material due to general, pitting, and crevice corrosion with the Water Chemistry and One-Time Inspection programs, consistent with the SRP-LR Section 3.2.2.2.8, item 2, further evaluation criteria. The staff concludes 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.

Item 3. LRA Section 3.2.2.2.8.3, associated with LRA Table 3.2.1, item 3.2.1.16, addresses loss of material due to general, pitting, and crevice corrosion in steel piping, piping components, and piping elements exposed to lubricating oil. The applicant stated that this item is not applicable because STP has no in-scope carbon steel components exposed to lubricating oil in the ESF systems. The staff reviewed LRA Sections 2.3.2 and 3.2, and the UFSAR, and finds that STP has no in-scope steel piping, piping components, or piping elements exposed to lubricating oil in the ESF systems.

3.2.2.2.9 Loss of Material Due to General, Pitting, Crevice Corrosion, and Microbiologically-Influenced Corrosion

LRA Section 3.2.2.2.9, associated with LRA Table 3.2.1, item 3.2.1.17, addresses steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil. The applicant stated that this item is applicable only to BWRs. The staff noted that SRP-LR Table 3.2-1, item 3.2.1.17 is applicable to both PWRs and BWRs. However, based upon the staff's review of LRA Sections 2.3.2 and 3.2, and the applicant's UFSAR, the staff determined that the applicant does not have any in-scope buried steel piping, piping components, and piping elements in the ESF systems.

3.2.2.2.10 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's QA Program.

3.2.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.2.2-1 through 3.2.2-4, 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.

3.2.2.3.1 Engineered Safety Features—Summary of Aging Management Evaluation—Containment Spray System—LRA Table 3.2.2-1

The staff reviewed LRA Table 3.2.2-1, which summarizes the results of AMR evaluations for the containment spray system component groups.

The staff's review did not find any items indicating plant-specific notes F through 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 associated with notes A through E is documented in SER Section 3.2.2.1.

3.2.2.3.2 Engineered Safety Features—Summary of Aging Management Evaluation—Integrated Leak Rate Test System—LRA Table 3.2.2-2

The staff reviewed LRA Table 3.2.2-2, which summarizes the results of AMR evaluations for the ILRT system component groups.

The staff's review did not find any items indicating plant-specific notes F through 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 associated with notes A through E is documented in SER Section 3.2.2.1.

3.2.2.3.3 Engineered Safety Features—Summary of Aging Management Evaluation—Residual Heat Removal System—LRA Table 3.2.2-3

<u>Fiberglass Insulation Exposed to Plant Indoor Air</u>. In LRA Table 3.2.2-3, the applicant stated that for fiberglass insulation exposed to plant indoor air, there is no aging effect, and no AMP is proposed. The AMR item cites generic note J.

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff noted that fiberglass insulation is commonly used at nuclear power plants and that the applicant credited the insulation with an intended function of "insulate," which is defined in Table 2.1-1 as controlling heat loss. The staff also noted that in a dry environment, without potential for water leakage, spray, or condensation, fiberglass is expected to be inert to environmental effects. The staff further noted that fiberglass insulation has the potential for prolonged retention of any moisture to which it is exposed, and prolonged exposure to moisture may increase thermal conductivity, thereby degrading the insulating characteristics. By letter dated September 22, 2011, the staff issued RAI 3.1.2.3.2-1 requesting that the applicant state whether all of the fiberglass is covered by jacketing and explain what procedure requirements are in place to prevent water intrusion into the insulation (e.g., seams on the bottom, overlapping seams) such that aging management is not required.

In its response dated November 21, 2011, the applicant stated the following:

(a) The chemical and volume control, feedwater, main steam, SG blowdown systems, and portions of RHR systems outside of containment are totally covered by jacketing with a few exceptions; these areas are not likely to receive environmental damage and RCPB penetrations.

(b) Plant specifications require that most of the insulation is jacketed.

(c) External surfaces walkdowns will detect component leakage that could negatively impact insulation.

(d) If leakage is discovered, corrective actions are initiated to address the leak's impact on the insulation.

(e) Where jacketing is provided, plant specifications include controls such as overlap of joints, horizontal run jacketing is oriented to shed water, etc.

The staff finds the applicant's response and proposal acceptable for the following reasons:

(a) Most of the insulation is jacketed.

(b) Those areas not covered by jacketing have a low likelihood of environmental damage or are associated with piping inside the containment in the vicinity of the reactor heat source such that during normal operations moisture would not penetrate through the insulation. Additionally, during RFOs, inspections are conducted that would detect leakage.

(c) Plant specifications provide guidance for installing the jacketing in such a way as to shed water.

(d) Fiberglass and calcium silicate are expected to be inert to environmental effects if they remain dry.

(e) When plant walkdowns detect leakage, corrective actions are taken to address the wetted insulation.

The staff's concern described in RAI 3.1.2.3.2-1 is resolved.

<u>Stainless Steel Heat Exchangers (RHR, RHR Pump Seal Water Cooler, RCP Thermal Barrier Cooler, and the CVCS Seal Water Return, Boron Thermal Regeneration System Letdown Reheat, Excess Letdown, Letdown, and Regenerative Heat Exchangers) Exposed to Treated Borated Water (Internal)</u>. In LRA Tables 3.2.2-3, 3.3.2-6, and 3.3.2-19, as revised by STPNOC's letter dated July 31, 2012, the applicant stated that the stainless steel RHR, RHR pump seal water cooler, RCP thermal barrier cooler, and the CVCS seal water return, Boron Thermal Regeneration System letdown reheat, excess letdown, letdown, and regenerative heat

exchangers exposed to treated borated water will be managed for reduction of heat transfer by the Water Chemistry and One-Time Inspection programs. The AMR items cite generic note H.

The staff noted that this material and environment combination is identified in the GALL Report, which addresses stainless steel heat exchanger components and tubes exposed to treated borated water and recommends TLAAs to manage cumulative fatigue damage; however, the applicant has identified this additional aging effect. The applicant addressed the GALL Report identified aging effects for this component, material, and environment combination in LRA Section 3.3.2.2.1.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection programs are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.4 respectively. The staff noted that the Water Chemistry Program manages loss reduction of heat transfer by monitoring and controlling the chemical environment in the reactor coolant and related auxiliary systems within industry guidelines to mitigate fouling. The staff finds the applicant's proposal to manage aging using the Water Chemistry and One-Time Inspection programs acceptable because they will limit the concentration of chemicals known to cause corrosion and add chemicals to inhibit degradation. This will minimize fouling while confirming the effectiveness of the Water Chemistry Program by conducting one-time inspections and using acceptance criteria consistent with the design and standards or ASME Code Section XI, as applicable for the component.

<u>Conclusion</u>. 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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.3.4 Engineered Safety Features—Summary of Aging Management Evaluation—Safety Injection System—LRA Table 3.2.2-4

The staff reviewed LRA Table 3.2.2-4, which summarizes the results of AMR evaluations for the safety injection system component groups. The staff's evaluation of the items associated with notes A through E is documented in SER Section 3.2.2.1.

<u>Stainless Steel Tanks Exposed to Plant Indoor Air</u>. By letter dated February 18, 2014, the applicant revised LRA Table 3.2.2-4 to state that the stainless steel RWST externally exposed to indoor air will be managed for cracking by the External Surfaces Monitoring Program. The AMR item cites generic note H. The staff noted that, although this material and environment combination was identified as not having any aging effects requiring management in the GALL Report, the applicant identified this additional aging effect based on plant-specific operating experience as discussed in its response dated February 18, 2014, to RAI B2.1.16-3. The applicant addressed the other GALL Report identified aging effects for this component, material and environment combination by AMR items in LRA Table 3.2.2-4.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.16. The staff noted that the applicant committed to perform a one-time internal inspection of the RWST to confirm the effectiveness of the previous corrective actions to repair the leaking tank floor. The staff finds the applicant's proposal to manage aging using the External Surfaces Monitoring Program acceptable because the periodic visual inspections of the tank's exterior surfaces at least every refueling outage, in conjunction with the one-time verification of previous corrective actions, are capable of identifying cracking of the RWST before its intended functions are adversely affected.

Stainless Steel Tank Exposed to Concrete. In LRA Table 3.2.2-4, as revised by letter dated June 3, 2014, the applicant stated that stainless steel tanks externally exposed to concrete will be managed for loss of material by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The AMR item cites generic note G, and plant-specific note 3, which state that for tanks sitting directly on concrete a volumetric examination of the bottom of the tank is performed from inside the tank in lieu of an external inspection.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the GALL Report, Revision 2, item SP-137, which states that stainless steel tanks exposed to concrete should be managed for loss of material due to pitting and crevice corrosion, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination. The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.18. The staff finds the applicant's proposal to manage aging using the above program acceptable because periodic volumetric inspections of the tank bottom conducted every 10 years is capable of confirming that no degradation occurs due to potential water leakage, consistent with GALL Report AMP XI.M29, "Aboveground Metallic Tanks."

Conclusion. 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 functions will remain 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 system components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will remain consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3 Aging Management of Auxiliary Systems

This section of the SER documents the staff's review of the applicant's AMR results for the auxiliary systems components and component groups of the following systems:

- fuel handling system
- spent fuel pool cooling and cleanup system
- cranes and hoists
- ECW and ECW screen wash system
- reactor makeup water system
- CCW system
- compressed air system
- primary process sampling system
- chilled water HVAC system

- electrical auxiliary building and control room HVAC system
- fuel handling building HVAC system
- mechanical auxiliary building HVAC system
- miscellaneous HVAC systems (in scope)
- containment building HVAC system
- standby diesel generator building HVAC system
- containment hydrogen monitoring and combustible gas control system
- fire protection system
- standby diesel generator fuel oil storage and transfer system
- chemical and volume control system
- standby diesel generator and auxiliaries system
- nonsafety-related diesel generators and auxiliary fuel oil system
- liquid waste processing system
- radioactive vents and drains system
- nonradioactive waste plumbing drains and sumps system
- oily waste system
- radiation monitoring (area and process) mechanical system
- miscellaneous systems in scope ONLY for Criterion 10 CFR 54.4(a)(2):
  - boron recycling
  - condensate storage
  - condensate
  - ECP makeup
  - gaseous waste processing
  - low-pressure nitrogen
  - MAB plant vent header (radioactive)
  - nonradioactive chemical waste
  - open loop auxiliary cooling
  - potable water and well water
  - secondary process sampling
  - solid waste processing
  - turbine vents and drains
- lighting diesel generator

3.3.1 Summary of Technical Information in the Application

LRA Section 3.3 provides AMR results for the auxiliary systems components and component groups. LRA Table 3.3.1, “Summary of Aging Management Evaluations in Chapter VII of NUREG-1801 for Auxiliary Systems,” is a summary comparison of the applicant’s AMRs with those evaluated in the GALL Report for the components and component groups of the auxiliary systems.

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 operating experience review included industry sources, 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 the effects of aging for auxiliary system components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions remain 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 to examine the applicant's AMPs and related documentation to confirm the applicant's claims that certain AMPs were consistent with the corresponding GALL Report AMPs. The staff did not repeat its review of the matters described in the GALL Report. The staff's evaluations of the AMPs are documented in SER Section 3.0.3.

The staff reviewed the AMRs to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did confirm that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. Details of the staff's evaluation are discussed in SER Sections 3.3.2.1 and 3.3.2.2.

The staff also reviewed the AMRs not consistent with or not addressed in the GALL Report. The review evaluated whether all plausible aging effects were identified and whether the aging effects listed were appropriate for the combination of materials and environments specified. Details of the staff's evaluation are discussed in SER Section 3.3.2.3.

For components 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 confirm the applicant's claims.

Table 3.3-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.3 and addressed in the GALL Report.

Table 3.3-1 Staff Evaluation for Auxiliary System Components in the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel cranes—structural girders exposed to air-indoor uncontrolled (external) (3.3.1.1)	Cumulative fatigue damage	TLAA to be evaluated for structural girders of cranes. SRP-LR, Section 4.7, provides generic guidance for meeting the requirements of 10 CFR 54.21(c)(1).	Yes	TLAA	Fatigue is a TLAA (see SER Sections 3.3.2.2.1 and 4.7.1)

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 and stainless steel piping, piping components, piping elements, and heat exchanger components exposed to air-indoor uncontrolled, treated borated water or treated water (3.3.1.2)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Fatigue is a TLAA (see SER Sections 3.3.2.2.1 and 4.3.5)
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	BWR only (staff noted that this item is applicable to STP)	Consistent with the GALL Report (see SER Section 3.3.2.2.2)
Stainless steel piping, piping components, and piping elements exposed to sodium pentaborate solution > 60 °C (140 °F) (3.3.1.4)	Cracking due to SCC	Water Chemistry and One-Time Inspection	Yes	BWR only	Not applicable to PWRs, therefore not applicable to STP (see SER Section 3.3.2.1.1)
Stainless steel and stainless clad steel heat exchanger components exposed to treated water > 60 °C (140 °F) (3.3.1.5)	Cracking due to SCC	A plant-specific AMP is to be evaluated.	Yes	BWR only	Not applicable to STP (see SER Section 3.3.2.2.3, item 2)
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 the GALL Report (see SER Section 3.3.2.2.3, item 3)
Stainless steel non-regenerative heat exchanger components exposed to treated borated water > 60 °C (140 °F) (3.3.1.7)	Cracking due to SCC and cyclic loading	Water Chemistry and a plant-specific verification program. An acceptable verification program is to include temperature and radioactivity monitoring of the shell side water and eddy current testing of tubes.	Yes	Water Chemistry Program and One-Time Inspection Program	Consistent with the GALL Report (see SER Section 3.3.2.2.4, item 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 regenerative heat exchanger components exposed to treated borated water > 60 °C (140 °F) (3.3.1.8)	Cracking due to SCC and cyclic loading	Water Chemistry and a plant-specific verification program. The AMP is to be augmented by verifying the absence of cracking due to SCC and cyclic loading. A plant-specific AMP is to be evaluated.	Yes	Water Chemistry Program and One-Time Inspection Program	Consistent with the GALL Report (see SER Section 3.3.2.2.4, item 2)
Stainless steel high-pressure pump casings 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 Program and One-Time Inspection Program	Consistent with the GALL Report (see SER Section 3.3.2.2.4 item 3)
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 to STP	Not applicable to STP (see SER Section 3.3.2.2.4, item 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 Program	Consistent with the GALL Report (see SER Section 3.3.2.2.5.1)
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 that determines and assesses the qualified life of the linings in the environment is to be evaluated.	Yes	Not applicable to STP	Not applicable (see SER Section 3.3.2.2.5, item 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
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	Not applicable to STP	Not applicable to STP (see SER Section 3.3.2.2.6)
Steel piping, piping components, 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 the GALL Report (see SER Section 3.3.2.2.7.1)
Steel RCP 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	Consistent with the GALL Report (see SER Section 3.3.2.2.7.1)
Steel RCP 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 the GALL Report (see SER Section 3.3.2.2.7.1)
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	BWR only	Not applicable to PWRs, therefore not applicable to STP (see SER Section 3.3.2.1.1)
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 pitting corrosion (steel only), and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.3.2.2.7, item 3)
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 Program	Consistent with the 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 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 programs	Consistent with the GALL Report (see SER Section 3.3.2.2.9, item 1)
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 programs	Consistent with the GALL Report (see SER Section 3.3.2.2.9, item 2)
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 to STP	Not applicable to STP (see SER Section 3.3.2.2.10, item 1)
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	BWR only	Not applicable to PWRs, therefore not applicable to STP (see SER Sections 3.3.2.1.1 and 3.3.2.2.10, item 2)
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	BWR only	Not applicable to PWRs, therefore not applicable to STP (see SER Sections 3.3.2.1.1 and 3.3.2.2.10, item 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
Copper alloy 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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and External Surfaces Monitoring Program	Consistent with the GALL Report (see SER Section 3.3.2.2.10, item 3)
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 Program	Consistent with the GALL Report (see SER Section 3.3.2.2.10, item 4)
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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, and External Surfaces Monitoring programs	Consistent with the GALL Report (see SER Section 3.3.2.2.10, item 5)
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 Program	Consistent with the GALL Report (see SER Section 3.3.2.2.10, item 6)
Stainless steel piping, piping components, and piping elements exposed to soil (3.3.1.29)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Not applicable to STP	Not applicable to STP (see SER Section 3.3.2.2.10, item 7)
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	BWR only	Not applicable to PWRs, therefore not applicable to STP (see SER Sections 3.3.2.1.1 and 3.3.2.2.10, item 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
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	BWR only	Not applicable to PWRs, therefore not applicable to STP (see SER Section 3.3.2.1.1)
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 and One-Time Inspection	Consistent with the GALL Report (see SER Section 3.3.2.2.12, item 1)
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 the GALL Report (see SER Section 3.3.2.2.12, item 2)
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 Program and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the 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	Not applicable to STP	Not applicable to STP (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	BWR only	Not applicable to PWRs, therefore not applicable to STP (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 piping, piping components, and piping elements exposed to treated water > 60 °C (140 °F) (3.3.1.37)	Cracking due to SCC and IGSCC	BWR Reactor Water Cleanup System	No	BWR only	Not applicable to PWRs, therefore not applicable to STP (see SER Section 3.3.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to treated water > 60 °C (140 °F) (3.3.1.38)	Cracking due to SCC	BWR Stress-Corrosion Cracking and Water Chemistry	No	BWR only	Not applicable to PWRs (see SER Section 3.3.2.1.1)
Stainless steel BWR spent fuel storage racks exposed to treated water > 60 °C (140 °F) (3.3.1.39)	Cracking due to SCC	Water Chemistry	No	BWR only	Not applicable to PWRs, therefore not applicable to STP (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 to STP	Not applicable to STP (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 to STP	Not applicable to STP (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 to STP	Not applicable to STP (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 Program	Consistent with the GALL Report (see SER Section 3.0.3.2.5)
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 to STP	Not applicable to STP (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 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 Program	Consistent with the GALL Report (see SER Section 3.3.2.1.14)
Stainless steel and stainless clad steel piping, piping components, piping elements, and heat exchanger components exposed to closed-cycle cooling water > 60 °C (140 °F) (3.3.1.46)	Cracking due to SCC	Closed-Cycle Cooling Water System	No	Closed-Cycle Cooling Water Program	Consistent with the GALL Report
Steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to closed-cycle cooling water (3.3.1.47)	Loss of material due to general, pitting, and crevice corrosion	Closed-Cycle Cooling Water System	No	Closed-Cycle Cooling Water Program	Consistent with the 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 Program	Consistent with the GALL Report
Stainless steel, steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water (3.3.1.49)	Loss of material due to MIC	Closed-Cycle Cooling Water System	No	BWR only	Not applicable to PWRs, therefore not applicable to STP (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 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 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 Program	Consistent with the 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 Program	Consistent with the GALL Report
Steel compressed air system piping, piping components, and piping elements exposed to condensation (internal) (3.3.1.53)	Loss of material due to general and pitting corrosion	Compressed Air Monitoring	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report (see SER Section 3.3.2.1.6)
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	Consistent with GALL Report (see SER Section 3.3.2.1.6)
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 Program	Consistent with the GALL Report
Steel HVAC ducting and components external surfaces exposed to air-indoor uncontrolled (external) (3.3.1.56)	Loss of material due to general corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring Program	Consistent with the GALL Report
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 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 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 Program or Fire Protection Program	Consistent with the GALL Report (see SER Section 3.3.2.1.7)
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 Program	Consistent with the 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 Program	Consistent with the 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 Program	Consistent with the GALL Report
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 to STP	Not applicable to STP (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	Fire Protection Program	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to fuel oil (3.3.1.64)	Loss of material due to general, pitting, and crevice corrosion	Fire Protection and Fuel Oil Chemistry	No	Fire Protection and Fuel Oil Chemistry programs	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
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	No	Fire Protection Program and Structures Monitoring Program	Consistent with the GALL Report
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	No	Fire Protection Program and Structures Monitoring Program	Consistent with the GALL Report
Reinforced concrete structural fire barriers—walls, ceilings, and floors exposed to air-outdoor or air-indoor uncontrolled (3.3.1.67)	Loss of material due to corrosion of embedded steel	Fire Protection and Structures Monitoring	No	Fire Protection Program and Structures Monitoring Program	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to raw water (3.3.1.68)	Loss of material due to general, pitting, crevice, and MIC and fouling	Fire Water System	No	Fire Water System Program	Consistent with the GALL Report
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 Program	Consistent with the GALL Report
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 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 piping, piping components, and piping elements exposed to moist air or condensation (internal) (3.3.1.71)	Loss of material due to general, pitting, and crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report
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 the GALL Report (see SER Section 3.3.2.1.9)
Steel crane structural girders in load handling system exposed to air-indoor uncontrolled (external) (3.3.1.73)	Loss of material due to general corrosion	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	No	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Consistent with the GALL Report
Steel cranes—rails exposed to air-indoor uncontrolled (external) (3.3.1.74)	Loss of material due to wear	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	No	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Consistent with the GALL Report
Elastomer seals and components exposed to raw water (3.3.1.75)	Hardening and loss of strength due to elastomer degradation; loss of material due to erosion	Open-Cycle Cooling Water System	No	Not applicable to STP	Not applicable to STP (see SER Section 3.3.2.1.1)
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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and External Surfaces Monitoring Program	Consistent with the GALL Report (see SER Section 3.3.2.1.2)

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 (3.3.1.77)	Loss of material due to general, pitting, crevice, galvanic, and MIC and fouling	Open-Cycle Cooling Water System	No	Open-Cycle Cooling Water System Program	Consistent with the GALL Report
Stainless steel, Ni-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	Open-Cycle Cooling Water System Program and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.3.2.1.3)
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 and External Surfaces Monitoring Program	Consistent with the GALL Report (see SER Section 3.3.2.1.4)
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	Open-Cycle Cooling Water System Program	Consistent with the GALL Report
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	Open-Cycle Cooling Water System Program and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.3.2.1.5)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
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 Program	Consistent with the 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	Open-Cycle Cooling Water System Program	Consistent with the GALL Report
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 Program and Selective Leaching of Aluminum Bronze Program	Consistent with the GALL Report (see SER Section 3.3.2.1.13)
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 Program	Consistent with the 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	Structures Monitoring Program	Consistent with the GALL Report
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 to STP	Not applicable to STP (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
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	Loss of Material Due to Boric Acid Corrosion	Consistent with the GALL Report (see SER Section 3.3.2.1.12)
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 Program	Consistent with the 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 > 60 °C (140 °F) (3.3.1.90)	Cracking due to SCC	Water Chemistry	No	Water Chemistry Program and One-Time Inspection Program	Consistent with the GALL Report (see SER Section 3.3.2.1.11)
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 Program and One-Time Inspection Program	Consistent with the GALL Report (see SER Section 3.3.2.1.8)
Galvanized steel piping, piping components, and piping elements exposed to air-indoor uncontrolled (3.3.1.92)	None	None	No	None	Consistent with the GALL Report (see SER Section 3.3.2.1.9)
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 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 and Ni-alloy piping, piping components, and piping elements exposed to air-indoor uncontrolled (external) (3.3.1.94)	None	None	No	None	Consistent with the 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 the GALL Report
Steel and stainless steel piping, piping components, and piping elements in concrete (3.3.1.96)	None	None	No	None	Consistent with the GALL Report (see SER Section 3.3.2.1.10)
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 the 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 the 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 the GALL Report

SER Section 3.3.2.1 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. SER Section 3.3.2.2 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. SER Section 3.3.2.3 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 auxiliary system components is documented in SER Section 3.0.3.

3.3.2.1 AMR Results That Are Consistent with the GALL Report

LRA Section 3.3.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the auxiliary system components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
- Bolting Integrity
- Boric Acid Corrosion
- Buried Piping and Tanks Inspection
- Closed-Cycle Cooling Water System
- External Surfaces Monitoring Program
- Fire Protection
- Fire Water System
- Flow-Accelerated Corrosion
- Fuel Oil Chemistry
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems
- Lubricating Oil Analysis
- One-Time Inspection
- One-Time Inspection of ASME Code Class 1 Small-Bore Piping
- Open-Cycle Cooling Water System
- Selective Leaching of Aluminum Bronze
- Selective Leaching of Materials
- Structures Monitoring Program
- Water Chemistry

LRA Tables 3.3.2-1 through 3.3.2-27 summarize AMRs for the auxiliary systems components and indicate AMRs claimed to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant had claimed consistency and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine whether the plant-specific components in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR item describing how the information in the tables aligns with the information in the GALL Report. The staff reviewed those AMRs with notes A through E, which indicate how the AMR was consistent with the GALL Report.

Note A indicates that the AMR 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 confirm 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 confirm consistency with the GALL Report and 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 confirm 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 confirm 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 had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR 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 confirm consistency with the GALL Report and determined whether the identified AMP would manage the aging effect consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

The staff audited and reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, it did confirm that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. The staff's evaluation is discussed below.

The staff reviewed the LRA to confirm that the applicant provided a brief description of the system, components, materials, and environments; stated that the applicable aging effects were reviewed and evaluated in the GALL Report; and identified those aging effects for the auxiliary systems' components that are subject to an AMR.

On the basis of its audit and review, the staff determines that, for AMRs not requiring further evaluation as identified in LRA Table 3.3.1, the applicant's references to the GALL Report are acceptable, and no further staff review is required.

3.3.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.3.1, items 3.3.1.4, 3.3.1.17, 3.3.1.23, 3.3.1.24, 3.3.1.30, 3.3.1.31, 3.3.1.36 through 3.3.1.39, and 3.3.1.49, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable because the associated items are only applicable to BWRs. In the applicant's 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 noted that STP is a PWR with a dry ambient containment. Based on this determination, the staff finds these items are not applicable to STP.

LRA Table 3.3.1, item 3.3.1.40, is associated with managing steel tanks in the diesel fuel oil system exposed to air-outdoor (external) for loss of material due to general, pitting, and crevice corrosion. The applicant stated that this item is not applicable to STP because STP has no in-scope steel tanks exposed to air-outdoor (external) in this system, and the applicable items in the GALL Report were not used. The staff reviewed LRA Sections 2.3.3 and 3.3, and the UFSAR, and finds that the applicant's statement is acceptable. Therefore, the staff concluded this item is not applicable to STP.

LRA Table 3.3.1, item 3.3.1.87, is associated with managing boraflex spent fuel storage racks with neutron-absorbing sheets exposed to treated borated water for reduction of neutron-absorbing capacity due to boraflex degradation. The applicant stated that, while boraflex is installed in one region of the spent fuel pool, this item is not applicable to STP because STP does not take credit for any flux reductions from the boraflex. The staff reviewed LRA Sections 2.3.3 and 3.3, and UFSAR Sections 9.1.2 and 4.3.2.6.2, and finds that the applicant's statement is acceptable. Therefore, the staff concluded this item is not applicable to STP.

LRA Table 3.3.1, item 3.3.1.41, is associated with cracking due to cyclic loading and SCC. The applicant stated that this item is not applicable to STP because it has no in-scope high-strength steel closure bolting in the auxiliary systems. The staff reviewed the LRA and UFSAR and finds that the applicant's statement is acceptable. Therefore, the staff concluded this item is not applicable to STP.

LRA Table 3.3.1, item 3.3.1.42, is associated with loss of material due to general corrosion in steel closure bolting exposed to air with steam or water leakage. The GALL Report recommends GALL Report AMP XI.M18, "Bolting Integrity," to manage loss of material due to general corrosion for this component group. The applicant stated that this item is not applicable because it has no in-scope steel closure bolting exposed to steam or water leakage in the auxiliary systems. The staff evaluated the applicant's statement and found it acceptable for the following reasons:

- All auxiliary system closure bolting exposed to the plant indoor air environment is being managed for loss of material by items 3.3.1.43 or 3.4.1.22, which use the Bolting Integrity Program, or 3.3.1.55, which uses the External Surfaces Monitoring Program.
- The use of the Bolting Integrity Program is the same program recommended by the GALL Report for item 3.3.1.42.
- The External Surfaces Monitoring Program conducts periodic walkdowns similar to those for the Bolting Integrity Program, which would identify bolted connection joint leakage before the leakage becomes excessive.

- For those items being managed by the External Surfaces Monitoring Program, the same components are being managed for loss of preload by the Bolting Integrity Program; therefore, the preventive actions related to bolt torque, proper use of lubricants, etc., would be included in the age managing of the components.

Therefore, the staff concluded this item is not applicable to STP.

LRA Table 3.3.1, item 3.3.1.44, addresses steel compressed air system closure bolting exposed to condensation. The GALL Report recommends GALL Report AMP XI.M18, "Bolting Integrity," to manage loss of material due to general, pitting, and crevice corrosion for this component group. The applicant stated that this item is not applicable because it has no closure bolting exposed to condensation in the compressed air system. Although the staff could not confirm that the compressed air system closure bolting would not be exposed to condensation, it finds the applicant's proposal acceptable because LRA Table 3.3.2-7, "Compressed Air System," states that all steel closure bolting in the system is being managed for loss of material by item 3.3.1.43 (i.e., steel closure bolting exposed to indoor uncontrolled air being managed for loss of material) using the Bolting Integrity Program, which is the same program recommended by item 3.3.1.44.

LRA Table 3.3.1, item 3.3.1.62 is associated with loss of material due to wear in aluminum piping, piping components, and piping elements exposed to raw water. The applicant stated that this is not applicable to STP because STP does not have in-scope aluminum components exposed to raw water in the fire protection system. The staff reviewed the LRA and UFSAR and finds the applicant's statement acceptable.

LRA Table 3.3.1, item 3.3.1.75, is associated with hardening and loss of strength due to elastomer degradation; loss of material due to erosion in elastomer seals and components exposed to raw water. The applicant stated this item is not applicable because STP has no in-scope elastomer components exposed to raw water in the open-cycle cooling water systems. The staff reviewed LRA Sections 2.3.3 and 3.3, and the UFSAR, and finds the applicant's statement acceptable.

3.3.2.1.2 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion; Fouling that Leads to Corrosion; Lining/Coating Degradation

LRA Table 3.3.1, item 3.3.1.76, addresses steel piping components (without lining/coating or with degraded lining/coating), exposed to raw water, which will be managed for loss of material due to general, pitting, and crevice corrosion, MIC; fouling; and lining/coating degradation. For the AMR items that cite generic note E, the LRA credits either the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program or External Surfaces Monitoring Program to manage the aging effect for carbon steel or iron piping, piping components, and piping elements. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed.

GALL Report AMP XI.M20 recommends using appropriate materials along with preventive measures, such as chemical treatment whenever the potential for biological fouling exists or flushing of infrequently used systems to manage aging. In addition, GALL Report AMP XI.M20 recommends inspection methods including visual or nondestructive examination and testing frequencies that are in accordance with the applicant's docketed response to GL 89-13. The staff noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting

Components Program or External Surfaces Monitoring Program proposes to manage the aging of these components and piping elements through the use of periodic visual inspections. The staff also noted that the applicant is using these programs because the components are exposed to waste streams or drains and not to an open-cycle environment that is used to remove heat to the ultimate heat sink. The staff observed that in LRA Table 3.3.2-27, the carbon steel piping exposed to raw water is being managed for loss of material by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The LRA noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program was being used because the internal environment is comprised of raw water, as opposed to nonradioactive waste streams for other items citing 3.3.1.76. It was not clear why the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program was more appropriate for this raw water environment. By letter dated September 22, 2011, the staff issued RAI 3.3.1.76-1 requesting that the applicant justify the use of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage loss of material for the carbon steel piping exposed to raw water in the miscellaneous systems to justify why chemical treatments or flushing is not required for these components.

In its response dated November 21, 2011, the applicant stated that the systems in LRA Table 3.3.2-27 that have carbon steel piping with an internal environment of raw water are the ECP makeup system and the open loop auxiliary cooling water system. The applicant further stated that these systems are nonsafety-related and perform no safety functions. The applicant stated that these components are scoped in the license renewal based on 10 CFR 54.4(a)(2) for spatial interaction and do not provide cooling to any safety-related systems. The applicant also states that because these components are scoped in for spatial interaction, loss of heat transfer is not an applicable AERM, and only loss of material is needed to be managed. The applicant further stated that because the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program manages loss of material, it is adequate to manage loss of material for the components exposed to raw water environment in the ECP makeup system and the open loop auxiliary cooling water system. The staff finds the applicant’s response acceptable because these components do not have the intended function of heat transfer and would not need to include chemical treatment of flushing to prevent fouling. Additionally, the GALL Report, Revision 2, indicates that components exposed to raw water not transferring heat to the ultimate heat sink can be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program or External Surfaces Monitoring Program. The staff’s concern described in RAI 3.3.1.76-1 is resolved.

The staff’s evaluations of the applicant’s Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program and External Surfaces Monitoring Program are documented in SER Sections 3.0.3.2.18 and 3.0.3.2.16, respectively. The staff noted that the applicant is using the periodic visual inspection programs for raw water that is not removing heat to the ultimate heat sink. In its review of components associated with item 3.3.1.76, for which the applicant cited generic note E, the staff finds the applicant’s proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program or External Surfaces Monitoring Program acceptable because the applicant is using a periodic visual inspection that is adequate to identify loss of material and because the raw water environment does not transfer heat from safety-related components to the ultimate heat sink, which is consistent with the guidance in the GALL Report.

The staff concludes that for LRA item 3.3.1.76, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.3 Loss of Material Due to General, Pitting, and Crevice Corrosion

LRA Table 3.3.1, item 3.3.1.78, addresses stainless steel, nickel alloy, and copper-alloy piping components exposed to raw water, which will be managed for loss of material due to general, pitting, and crevice corrosion. For the AMR items that cite generic note E, the LRA credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effect for these components. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed.

GALL Report AMP XI.M20 recommends using appropriate materials along with preventive measures, such as chemical treatment, whenever the potential for biological fouling exists or flushing of infrequently used systems to manage aging. In addition, GALL Report AMP XI.M20 recommends inspection methods including visual or nondestructive examination and testing frequencies that are in accordance with the applicant's docketed response to GL 89-13. The staff noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program proposes to manage the aging of the stainless steel, nickel alloy, and copper-alloy piping components through the use of periodic visual inspections. The staff also noted that the applicant is using this program because the components are exposed to waste drains and not to an open-cycle environment that is used to remove heat to the ultimate heat sink.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.18. The staff noted that the applicant is using the periodic visual inspection programs for raw water that is not removing heat to the ultimate heat sink. In its review of components associated with item 3.3.1.78, for which the applicant cited generic note E, 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 applicant is using a periodic visual inspection that is adequate to identify loss of material and because the raw water environment does not transfer heat from safety-related components to the ultimate heat sink, which is consistent with the guidance in the GALL Report.

The staff concludes that for LRA item 3.3.1.78, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.4 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 components exposed to raw water, which will be managed for loss of material due to pitting and crevice corrosion and fouling. For the AMR items that cite generic note E, the LRA credits either the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program or the External Surfaces Monitoring Program to manage the aging effect for these components. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed.

GALL Report AMP XI.M20 recommends using appropriate materials along with preventive measures, such as chemical treatment, whenever the potential for biological fouling exists or flushing of infrequently used systems to manage aging. In addition, GALL Report AMP XI.M20 recommends inspection methods including visual or nondestructive examination and testing frequencies that are in accordance with the applicant's docketed response to GL 89-13. The staff noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program or External Surfaces Monitoring Program proposes to manage the aging of the stainless steel piping, piping components, and piping elements through the use of periodic visual inspections. The staff also noted that the applicant is using these programs because the components are exposed to waste drains and not to an open-cycle environment that is used to remove heat to the ultimate heat sink.

The staff's evaluations of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program and External Surfaces Monitoring Program are documented in SER Sections 3.0.3.2.18 and 3.0.3.2.16, respectively. The staff noted that the applicant is using the periodic visual inspection programs for raw water that is not removing heat to the ultimate heat sink. In its review of components associated with item 3.3.1.79, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program and External Surfaces Monitoring Program acceptable because the applicant is using a periodic visual inspection that is adequate to identify loss of material and because the raw water environment does not transfer heat from safety-related components to the ultimate heat sink, which is consistent with the guidance in the GALL Report.

The staff concludes that for LRA item 3.3.1.79, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.5 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion; Fouling that Leads to Corrosion

LRA Table 3.3.1, item 3.3.1.81, addresses copper-alloy piping components exposed to raw water, which will be managed for loss of material due to general, pitting, and crevice corrosion, MIC, and fouling that leads to corrosion. For the AMR items that cite generic note E, the LRA credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effect for these components. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that these aging effects are adequately managed.

GALL Report AMP XI.M20 recommends using appropriate materials along with preventive measures, such as chemical treatment, whenever the potential for biological fouling exists or flushing of infrequently used systems to manage aging. In addition, GALL Report AMP XI.M20 recommends inspection methods, including visual or nondestructive examination, and testing frequencies that are in accordance with the applicant's docketed response to GL 89-13. The staff noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program proposes to manage the aging of the copper-alloy piping components through the use of periodic visual inspections. The staff also noted that the applicant is using this program because the components are exposed to a raw water environment of the liquid radioactive waste and ECP makeup system and not to an open-cycle environment that is used to remove heat to the ultimate heat sink.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.18. The staff noted that the applicant is using the periodic visual inspection program for raw water that is not removing heat to the ultimate heat sink. In its review of components associated with item 3.3.1.81 for which the applicant cited generic note E, 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 applicant is using a periodic visual inspection that is adequate to identify loss of material and because the raw water environment does not transfer heat from safety-related components to the ultimate heat sink, which is consistent with the guidance in the GALL Report.

The staff concludes that for LRA item 3.3.1.81, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.6 Loss of Material Due to General, Pitting, and Crevice Corrosion

LRA Table 3.3.1, items 3.3.1.53 and 3.3.1.54, address steel and stainless steel compressed air system piping, piping components, and piping elements exposed to condensation (internal), which will be managed for loss of material due to general and pitting corrosion and crevice corrosion (stainless steel only). For the AMR items that cite generic note E, the LRA credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage loss of material for carbon steel accumulators, compressors, filters, heat exchangers, piping, tanks, and valves; galvanized steel piping; stainless steel expansion joints, thermowells, flexible hoses, piping, tanks, tubing, and valves; and CASS valves internally exposed to plant indoor air. The GALL Report recommends GALL Report AMP XI.M24, "Compressed Air Monitoring," to ensure that these aging effects are adequately managed.

GALL Report AMP XI.M24 recommends maintaining moisture and other corrosive contaminants below acceptable limits via periodic samples and testing to mitigate loss of material. Additionally, the GALL Report AMP recommends periodic and opportunistic visual inspections of accessible internal surfaces to detect signs of loss of material due to corrosion. As described in UFSAR Section 9.3.1, the compressed air system is designed to supply instrument air meeting the requirements of ANSI/International Society of Automation (ISA) S7.0.01-1996, "Quality Standard for Instrument Air," dated November 1996. During an audit, the staff reviewed the applicant's instrument air quality test procedure and confirmed that the applicant periodically tests for particulate and oil contamination as well as the dew point at various locations throughout the instrument air system. The applicant's test acceptance criteria, as stated in its instrument air quality test procedure, are in accordance with ANSI/ISA S7.3, "Quality Standard for Instrument Air," as committed to in its response to GL 88-14. This standard has been superseded by ANSI/ISA S7.0.01-1996.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.18. This program proposes to manage cracking, loss of material, and hardening and loss of strength of the internal surfaces of steel, stainless steel, aluminum, copper alloy, stainless steel-cast austenitic, nickel alloys, glass and elastomer piping, piping components, ducting, and other components using periodic and opportunistic visual inspections, augmented by physical manipulation when appropriate. In its review of components associated with items 3.3.1.53 and 3.3.1.54, for which the applicant cited generic note E, 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 environment to which the components are exposed is indoor plant air, which is not a more aggressive environment than those recommended for aging management by GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components." As stated in GALL Report AMP XI.M38, the program includes visual inspections to ensure that existing environmental conditions are not causing material degradation that could result in a loss of component intended functions. Periodic and opportunistic visual inspections of internal surfaces are capable of detecting signs of loss of material due to corrosion in steel and stainless steel components.

3.3.2.1.7 Loss of Material Due to General Corrosion

LRA Table 3.3.1, item 3.3.1.58, addresses steel external surfaces exposed to air-indoor uncontrolled (external), air-outdoor (external), and condensation (external), which will be managed for loss of material due to general corrosion. For the AMR items that cite generic note E, the LRA credits the Fire Protection Program to manage loss of material due to general corrosion for carbon steel piping (Halon) and valves (Halon) exposed to plant indoor air (external). The GALL Report recommends GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," to ensure that these aging effects are adequately managed.

GALL Report AMP XI.M36 recommends using visual inspections to manage aging. The staff noted that the Fire Protection Program proposes to manage the aging of the carbon steel Halon piping and valves through the use of visual inspections at least once every 18 months, visual inspections once every 6 months to identify corrosion and mechanical damage in the Halon flow path, and a functional test of the Halon fire suppression system every 18 months by qualified inspectors.

The staff's evaluation of the applicant's Fire Protection Program is documented in SER Section 3.0.3.2.9. In its review of components associated with item 3.3.1.58 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Fire Protection Program acceptable because the program includes periodic visual inspections and functional tests that can detect signs of loss of material due to general corrosion for carbon steel components.

During its review of carbon steel dampers exposed to atmosphere and weather (internal) associated with item 3.3.1.58, for which the applicant cited generic note B, the staff noted that the LRA credits the External Surfaces Monitoring Program to manage loss of material due to general corrosion. The staff also noted that since the carbon steel dampers listed in LRA Tables 3.3.2-11 and 3.3.2-12 appear to describe an internal surface, internal inspections would be needed to appropriately manage the aging effect. However, the staff noted that the applicant's External Surfaces Monitoring Program is not credited for managing loss of material for internal surfaces. By letter dated August 15, 2011, the staff issued RAI B2.1.20-2 requesting that the applicant clarify how the carbon steel dampers exposed to an atmospheric weather internal environment in LRA Tables 3.3.2-11 and 3.3.2-12 will be periodically inspected by the External Surfaces Monitoring Program.

In its response dated September 15, 2011, the applicant stated that the supply HVAC tornado dampers for the fuel handling and mechanical auxiliary buildings, listed in LRA Tables 3.3.2-11 and 3.3.2-12, respectively, were inadvertently assigned to the External Surfaces Monitoring Program. The applicant also stated that it will amend the LRA to manage loss of material for these items with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. By letter dated November 11, 2011, the applicant revised LRA Tables 3.3.2-11 and 3.3.2-12 to manage the HVAC tornado dampers for loss of material using the Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The applicant also revised these two items to align with GALL Report item VIII.B1-6, and LRA Table 3.4-1, item 3.4.1.30. The staff finds the applicant's response acceptable because the applicant will manage the internal surfaces of the dampers consistent with the GALL Report recommendation in item VIII.B1-6 using a program that inspects the internal surfaces of components. The staff's concern described in RAI B2.1.20-2 is resolved.

The staff concludes that for LRA item 3.3.1.58, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.8 Loss of Material Due to Pitting and Crevice Corrosion

LRA Table 3.3.1, item 3.3.1.91, addresses stainless steel and steel with stainless steel cladding piping, piping components, and piping elements exposed to treated borated water, which will be managed for loss of material due to pitting and crevice corrosion. For the AMR items that cite generic note E, the LRA credits the Water Chemistry and One-Time Inspection programs to manage the aging effect for stainless steel piping components, bolting, tanks, heat exchanger components, and structural components. The GALL Report recommends GALL Report AMP XI.M2, "Water Chemistry," to ensure that these aging effects are adequately managed.

GALL Report AMP XI.M2 recommends using water chemistry control to minimize contaminant concentration to manage aging. The staff noted that the Water Chemistry and One-Time Inspection programs propose to manage the aging of stainless steel piping components, bolting, tanks, heat exchanger components, and structural components through the use of water chemistry controls to minimize contaminant concentrations along with a one-time visual inspection to confirm the effectiveness of the Water Chemistry Program.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection programs are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.4, respectively. In its review of components associated with item 3.3.1.91, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Water Chemistry and One-Time Inspection programs acceptable because the Water Chemistry Program establishes the plant water chemistry control parameters and their limits to mitigate aging and identifies the actions required if the parameters exceed the limits, and the One-Time Inspection Program prescribes appropriate visual, volumetric, or other inspection techniques capable of detecting pitting and crevice corrosion prior to loss of intended function to confirm the effectiveness of the water chemistry controls.

The staff concludes that for LRA item 3.3.1.91, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.9 Galvanized Steel Piping, Piping Components, and Piping Elements Exposed to Air-Indoor Uncontrolled—No Aging Effect

LRA Table 3.3.1, item 3.3.1.92, addresses galvanized steel piping, piping components, and piping elements exposed to air-indoor uncontrolled, which have no identified AERM. During its review of components associated with item 3.3.1.92, for which the applicant cited generic notes A or C, the staff noted that LRA Table 3.3.2-17 includes an AMR item for a galvanized carbon steel damper exposed to ventilation atmosphere (internal) in the fire protection system. The staff also noted similar AMR items for galvanized carbon steel dampers in other auxiliary systems that are associated with Table 3.3.1, item 3.3.1.72, and are managed for loss of material with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. By letter dated September 22, 2011, the staff issued RAI 3.3.1.92-1 requesting that the applicant state why the galvanized carbon steel damper exposed to ventilation atmosphere in LRA Table 3.3.2-17 has no AERM.

In its response dated November 21, 2011, the applicant revised LRA Table 3.3.2-17 to state that the galvanized carbon steel damper exposed to ventilation atmosphere has a loss of material aging effect that will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The applicant aligned the AMR item with LRA Table 3.3.1, item 3.3.1.72, which is associated with steel HVAC ducting and components exposed to condensation.

The staff finds the applicant’s response acceptable because the applicant’s revised aging management approach considers the potential for condensation in the galvanized carbon steel damper in the fire protection system. The staff noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program includes visual inspections that are capable of detecting corrosion degradation of the damper prior to loss of intended functions. The staff’s concern described in RAI 3.3.1.92-1 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 3.0.3.2.18. The staff noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program will use the work control process for preventive maintenance and visual inspections to detect loss of material. The staff also noted that the applicant’s program will use supplemental inspections at locations with the greatest likelihood of degradation. Based on its review of components initially associated with item 3.3.1.92, but revised to reference item 3.3.1.72, 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 visual inspections, in conjunction with the supplemental inspections at locations of likely significant degradation, are capable of detecting loss of material prior to loss of intended functions.

The staff’s evaluation of LRA item 3.3.1.72 is documented in SER Section 3.3.2.1. The staff concludes that for LRA item 3.3.1.92, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.10 Steel, Stainless Steel Piping, Piping Components, and Piping Elements Encased in Concrete—No Aging Effect

LRA Table 3.3.1, item 3.3.1.96, addresses steel and stainless steel piping, piping components, and piping elements encased in concrete, which have no identified AERM. During its review of components associated with item 3.3.1.96, for which the applicant cited generic notes A or C, the staff noted that the updated staff guidance in Revision 2 of the GALL Report states that steel piping, piping components, and piping elements encased in concrete do not need to be managed for aging provided that the attributes of the concrete are consistent with ACI 318 or ACI 349 standards and that plant operating experience indicates no degradation of the concrete. The staff also noted that if the conditions are not met, further evaluation is recommended. The staff further noted that ACI 318-71, "Building Code Requirements for Reinforced Concrete," was used by the applicant, as documented in UFSAR Section 3.8.4.2. By letter dated September 22, 2011, the staff issued RAI 3.3.1.96-1 requesting that the applicant state whether concrete degradation has occurred in the vicinity of the steel components embedded in concrete. If so, the staff asked the applicant to state what further evaluation has or will be performed to determine whether aging management of steel components embedded in concrete is needed.

In its response dated November 21, 2011, the applicant stated that its Structures Monitoring Program provides aging management for the concrete in which carbon steel and galvanized carbon steel components are encased and that none of the inspections have identified any degradation of the concrete greater in size than a hairline crack. The applicant also stated that the hairline cracks were evaluated and determined not to have any impact on the ability of the structure to perform its intended function, including protection of embedded steel components. The applicant further stated that the Structures Monitoring Program will continue to monitor the concrete, and any aging effects that might occur in the future will be managed to ensure that there is no loss of intended function.

The staff finds the applicant's response acceptable because the concrete encasing the steel components is designed and fabricated in accordance with ACI 318, and the applicant's operating experience does not indicate any concrete degradation that resulted in exposure of the encased components to a corrosive environment. The staff's concern described in RAI 3.3.1.96-1 is resolved.

The staff concludes that for LRA item 3.3.1.96, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.11 Cracking Due to Stress Corrosion Cracking

LRA Table 3.3.1, item 3.3.1.90, addresses stainless steel and steel with stainless steel cladding piping, piping components, piping elements, tanks, and fuel storage racks exposed to treated borated water greater than 60 °C (140 °F), which will be managed for cracking due to SCC. For the AMR item that cites generic note E, the LRA credits the Water Chemistry Program to manage the aging effect. The LRA also credits the One-Time Inspection Program to confirm the effectiveness of the Water Chemistry Program for adequate aging management of cracking. The GALL Report recommends GALL Report AMP XI.M2, "Water Chemistry," to ensure that the aging effect is adequately managed.

GALL Report AMP XI.M2 recommends using preventive measures, including water chemistry control, to manage the aging of these items by limiting the concentrations of chemical species known to cause SCC and controlling dissolved oxygen levels to minimize the environmental effect on SCC. The staff noted that the Water Chemistry Program proposes managing the aging of stainless steel piping, piping components, and piping elements through the use of water chemistry controls, and the One-Time Inspection Program provides confirmation of the effectiveness of the Water Chemistry Program to manage cracking.

The staff's evaluations of the applicant's Water Chemistry Program and One-Time Inspection Program are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.4, respectively. In its review of components associated with item 3.3.1.90, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Water Chemistry Program and One-Time Inspection Program acceptable because the Water Chemistry Program limits the concentrations of chemical species known to cause SCC and controls the dissolved oxygen level to minimize the environmental effect on SCC, and the One-Time Inspection Program includes a one-time inspection of selected components to confirm the effectiveness of the Water Chemistry Program so that it is ensured to adequately manage cracking due to SCC of these components.

The staff concludes that for LRA item 3.3.1.90, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.12   Loss of Material Due to Boric Acid Corrosion

LRA Table 3.3.1, item 3.3.1.88, addresses aluminum and copper alloy greater than 15 percent Zn piping, piping components, and piping elements exposed to air with borated water leakage. The GALL Report recommends GALL Report AMP XI.M10, "Boric Acid Corrosion," to manage loss of material due to boric acid corrosion for this component group. In the LRA, dated October 28, 2010, the applicant originally stated that this item was not applicable, stating that there were no in-scope aluminum or copper alloy greater than 15 percent Zn piping, piping components, or piping elements exposed to air with borated water leakage in the auxiliary systems.

LRA Section 3.3.2.1.19 states that the CVCS, an auxiliary system, contains an environment of borated water leakage. The staff noted that LRA Table 3.3.2-19, the AMR results for the CVCS, included an item for aluminum insulation; however, the only environment cited was plant indoor air (external). Given that borated water leakage is a recognized environment in the CVCS, it was not clear to the staff why the aluminum insulation in this system was not managed for loss of material due to boric acid corrosion. By letter dated September 22, 2011, the staff issued RAI 3.3.1.88-1 requesting that the applicant clarify whether aluminum insulation in the CVCS may be exposed to borated water leakage. If so, the staff asked the applicant to state how loss of material due to boric acid corrosion will be managed.

In its response dated October 25, 2011, the applicant stated that, although the aluminum sheathing could be exposed to borated water leakage, the aging management evaluation for a treated borated water leakage environment is considered applicable only for components that contain treated borated water and is not applicable for adjacent system components or insulation on the piping that contains the treated borated water. The staff found the response unacceptable because GALL Report AMP XI.M10 does not limit the air with borated water leakage environment to only those components that contain borated water. By letter dated December 14, 2011, the staff issued RAI 3.3.1.88-2 requesting that the applicant include AMR items for a borated water leakage environment for all in-scope, susceptible components—including the subject aluminum sheathing—that are adjacent to locations in borated water piping where leakage is most likely to occur.

In its response dated January 18, 2012, the applicant revised LRA Tables 3.3.2-19, 3.4.2-1, 3.4.2-3, and 3.4.2-5 to include AMR items for aluminum insulation jacketing exposed to an external environment of borated water leakage and managed with the Boric Acid Corrosion Program. In addition, the applicant performed a review of plant systems in the reactor containment building, fuel handling building, and mechanical electrical auxiliary building and identified several systems that contain in-scope components in the vicinity of components containing treated borated water. The applicant added AMR items to the affected LRA tables for aluminum, steel, galvanized steel, and copper alloy greater than 15 percent Zn piping, closure bolting, tank, and heat exchanger components exposed to an external environment of borated water leakage and managed with the Boric Acid Corrosion Program. The applicant also revised LRA Table 3.3.1, item 3.3.1.88; Table 3.4.1, item 3.4.1.38; and the descriptions of each of the affected systems in LRA Section 3 to reflect the changes.

The staff finds the applicant's response acceptable because the LRA has been revised to include AMR items for in-scope, susceptible components exposed to an external environment of borated water leakage. The staff notes that, for all items that reference LRA item 3.3.1.88, the applicant cites generic notes A and C and is managing these components for loss of material with the Boric Acid Corrosion Program, consistent with GALL Report recommendations. The staff's concern described in RAIs 3.3.1.88-1 and 3.3.1.88-2 is resolved.

The staff concludes that for LRA item 3.3.1.88, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.13 Loss of Material Due to Selective Leaching

LRA Table 3.3.1, item 3.3.1.84, addresses copper alloy greater than 15 percent Zn piping, piping components, piping elements, and heat exchanger components exposed to raw water, treated water, or CCCW, which will be managed for loss of material due to selective leaching. For the AMR items that cite generic note E, the LRA credits the Selective Leaching of Aluminum Bronze Program to manage the aging effect for copper alloy (aluminum greater than 8 percent). The GALL Report recommends GALL Report AMP XI.M33, "Selective Leaching," to ensure that these aging effects are adequately managed.

GALL Report AMP XI.M33 recommends using a one-time internal visual and mechanical examination of a representative sample of locations susceptible to selective leaching to demonstrate the presence or absence of selective leaching where there has not been previous experience of selective leaching. The staff noted that, based on plant-specific operating experience, selective leaching is occurring in copper alloy (aluminum greater than 8 percent) in the ECW system.

By letter dated June 3, 2014, the applicant amended the LRA to provide its responses to LR-ISG-2012-02, "Aging Management of Internals Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation" (ADAMS Accession No. ML13227A361). In the

LRA, the applicant indicated that loss of material/selective leaching that was detected in the copper alloy (aluminum greater than 8 percent) piping of the ECW system was considered to be recurring internals corrosion for the piping system. As a result, the applicant proposed a plant-specific program, the Selective Leaching of Aluminum Bronze Program, to manage this aging effect. The Selective Leaching of Aluminum Bronze Program proposes to manage the aging of copper alloy greater than 15 percent Zn piping, piping components, and piping elements components through the use of external visual inspections of aboveground piping and a walkdown of areas above susceptible buried piping locations to detect signs of leakage conducted every 6 months. Components found to have indications of through-wall dealloying are evaluated and scheduled for replacement by the CAP. Given that GALL Report AMP XI.M33 recommends internal visual and mechanical examinations to detect selective leaching, the staff issued RAI B2.1.37-1 requesting that the applicant revise LRA Section B2.1.37 to include periodic internal visual inspections coupled with mechanical examinations (e.g., hardness testing, destructive examination) capable of detecting the degree of selective leaching occurring in aluminum bronze components to establish a baseline understanding of the extent to which subsurface degradation has occurred to date and to monitor and trend this aging effect throughout the period of extended operation. The staff's evaluation of RAI B2.1.37-1 is documented in SER Section 3.0.3.3.3.

The staff's evaluation of the applicant's Selective Leaching of Aluminum Bronze Program is documented in SER Section 3.0.3.3.3. Until OI 3.0.3.3.3-2 is resolved, the staff cannot complete its evaluation of this AMR item. The staff conducted a followup audit of the applicant's program and supporting documentation on February 29, 2012, and issued RAI B2.1.37-3 by letter dated April 12, 2012, to address the information required to close OI 3.0.3.3.3-2.

The staff finds that for LRA item 3.3.1.84, it requires further information to complete its determination 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. The staff's issues are documented in OI 3.0.3.3.3-2.

3.3.2.1.14 Loss of Preload

LRA Table 3.3.1, item 3.3.1.45, addresses steel closure bolting exposed to air-indoor uncontrolled (external), which will be managed for loss of preload due to thermal effects, gasket creep, and self-loosening. During its review of components associated with item 3.3.1.45, the staff noted that, in LRA Tables 3.3.2-13 and 3.3.2-15, there were no AMR items for steel closure bolting exposed to air-indoor uncontrolled (external), which will be managed for loss of preload. By letter dated September 22, 2011, the staff issued RAI 3.3.2.13-1 requesting that the applicant provide AMR items for managing loss of preload for steel closure bolting exposed to air-indoor uncontrolled (external). In its response dated November 21, 2011, the applicant stated that LRA Tables 3.3.2.1-3 and 3.3.2-15 were revised to add loss of preload for steel closure bolting exposed to air-indoor uncontrolled (external).

The staff finds the applicant's response acceptable because the applicant revised LRA Tables 3.3.2.1-3 and 3.3.2-15 to include loss of preload and referenced Table 3.3.1, item 3.3.1.45, which is consistent with the GALL Report. The staff's concern described in RAI 3.3.2.13-1 is resolved.

The staff concludes that for LRA item 3.1.1.45, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

LRA Section 3.3.2.2 provides further evaluations of aging management, as recommended by the GALL Report, for the auxiliary systems components. The applicant provided information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- reduction of heat transfer due to fouling
- cracking due to SCC
- cracking due to SCC and cyclic loading
- hardening and loss of strength due to elastomer degradation
- reduction of neutron-absorbing capacity and loss of material due to general corrosion
- loss of material due to general, pitting, and crevice corrosion
- loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion
- loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling
- loss of material due to pitting and crevice corrosion
- loss of material due to pitting, crevice, and galvanic corrosion
- loss of material due to pitting, crevice, and microbiologically-influenced corrosion
- loss of material due to wear
- loss of material due to cladding breach

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluations to determine whether they adequately address those issues. In addition, the staff reviewed the applicant's further evaluations against the criteria in SRP-LR Section 3.3.2.2. The staff's review of the applicant's further evaluations follows.

3.3.2.2.1 Cumulative Fatigue Damage

Cumulative fatigue is an aging-related degradation mechanism caused by cyclic stresses on a component by either mechanical or thermal stresses. LRA Section 3.3.2.2.1 states that TLAAs are evaluated in accordance with 10 CFR 54.21(c)(1). For Table 3.3.1, items 3.3.1.1 and 3.3.1.2, the LRA states that evaluations of these TLAA items are addressed in Sections 4.7.1 and 4.3.5, respectively. The staff finds that the applicant's statements regarding these items are consistent with the further evaluation criteria of SRP-LR Section 3.3.2.2.1 and are, therefore, acceptable.

3.3.2.2.2 Reduction of Heat Transfer Due to Fouling

LRA Section 3.3.2.2.2, associated with LRA Table 3.3.1, item 3.3.1.3, addresses stainless steel heat exchanger tubes exposed to treated water. The applicant stated that this item is not applicable to STP because this item is only for BWRs, but the staff noted SRP-LR Table 3.3.1, item 3.3.1.3, states this item is applicable to both BWRs and PWRs. The staff also noted that, based on information in NUREG-1833, the technical basis for adding the related item, AP-62, to 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 staff noted that this item is applicable to STP.

Through its review of LRA Section 3.3, the staff noted that LRA Table 3.3.2-2, "Spent Fuel Pool Cooling," cites generic note G for stainless steel heat exchanger tubes exposed to treated borated water for reduction of heat transfer, indicating that this environment is not in the GALL Report for this component and material. For these components, the LRA specifies the Water Chemistry and One-Time Inspection programs as the applicable AMPs, which are consistent with the further evaluation criteria in SRP-LR Section 3.3.2.2.2. The staff finds the specified AMPs acceptable and discussed these components in more detail in SER Section 3.3.2.3.2.

3.3.2.2.3 Cracking Due to Stress-Corrosion Cracking

<u>Item 1</u>. LRA Section 3.3.2.2.3.1 and Table 3.3.1, item 3.3.1.4, are applicable to BWRs only; therefore, they are not applicable to STP. This information is provided in SER Section 3.3.2.1.1.

<u>Item 2</u>. LRA Section 3.3.2.2.3, item 2, associated with LRA Table 3.3.1, item 3.3.1.5, addresses stainless steel and stainless clad steel heat exchanger components exposed to treated water greater than 60 °C (140 °F). The applicant stated that this item is not applicable to STP because this item is only for BWRs.

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 60 °C (140 °F) present in the auxiliary systems, there were several systems with heat exchanger tubes exposed to treated borated water greater than 60 °C (140 °F). 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 LRA Table 3.3.1, items 3.3.1.7 and 3.3.1.8, which are associated with non-regenerative and regenerative heat exchanger tubes, and cited generic note E to indicate 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 2 for these components, which stated that the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Program. 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 items 3.3.1.7 and 3.3.1.8, which have comparable acceptance criteria as item 3.3.1.5; consequently, it will adequately manage this aging effect consistent with the CLB for the period of extended operation.

<u>Item 3</u>. LRA Section 3.3.2.2.3.3, associated with LRA Table 3.3.1, item 3.3.1.6, addresses stainless steel diesel engine exhaust piping components exposed to diesel exhaust, which will be managed for cracking due to SCC by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The criteria in SRP-LR, Revision 1, Section 3.3.2.2.3, item 3, states that cracking due to SCC could occur for stainless steel piping components exposed to diesel exhaust. The SRP-LR also states that the acceptance criteria

described in Branch Technical Position RLSB-1 should be used to ensure that a plant-specific AMP will adequately manage this aging effect. In addition, the equivalent item (3.3.1-83) in SRP-LR, Revision 2, states that GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," is capable of ensuring that this aging effect is adequately managed. GALL Report AMP XI.M38 recommends using periodic inspection to manage cracking due to SCC. The applicant addressed the further evaluation criteria of the SRP-LR by stating that cracking due to SCC for stainless steel diesel engine exhaust piping and expansion joint will be detected and characterized by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program.

During its review of components associated with item 3.3.1.6, the staff noted that LRA Table 3.3.2-21 includes an AMR item for stainless steel expansion joints exposed to diesel exhaust (internal); however, the LRA did not include SCC as an aging effect being managed for this component. By letter dated September 22, 2011, the staff issued RAI 3.3.2.2.3.3-1 requesting that the applicant provide the basis for not managing this component for SCC, as recommended by the GALL Report, or to provide a suitable AMP to manage this aging effect. In its response dated October 25, 2011, the applicant provided a revision to Table 3.3.2-21 by adding an item to manage cracking in the stainless steel expansion joint exposed to diesel exhaust. The staff finds this response acceptable because the applicant is now managing cracking of stainless steel components for the nonsafety-related diesel generators that are exposed to diesel exhaust consistent with the other stainless steel components in a similar environment and with the GALL Report. The staff's concern described in RAI 3.3.2.2.3.3-1 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 3.0.3.2.18. The staff noted that the applicant's AMP includes ultrasonic examinations to detect SCC of stainless steel components exposed to diesel exhaust and supplemental inspections with the locations and intervals based on the likelihood of degradation and on operating experience. 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 applicant's program includes volumetric examination using UT techniques, which provide ongoing opportunities to detect SCC of stainless steel components and will be supplemented by other established nondestructive examination techniques during periodic maintenance, predictive maintenance, surveillance testing, and corrective maintenance, as appropriate.

Based on the program identified, the staff determines that the applicant's program meets the further evaluation criteria of SRP-LR, Section 3.3.2.2.3, item 3. For those items associated with LRA Section 3.3.2.2.3.3, 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).

3.3.2.2.4 Cracking Due to Stress-Corrosion Cracking and Cyclic Loading

Item 1. LRA Section 3.3.2.2.4, item 1, associated with LRA Table 3.3.1, item 3.3.1.7, addresses cracking due to SCC and cyclic loading in stainless steel non-regenerative heat exchanger components exposed to treated borated water greater than 60 °C (140 °F), 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 that 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, which includes selected components at susceptible locations. The applicant stated that the One-Time Inspection Program is selected in lieu of eddy current testing of tubes and also stated that temperature and radioactivity monitoring of shell side water is performed by installed instrumentation.

The staff's evaluations of the applicant's Water Chemistry and the One-Time Inspection programs are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.4, 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 noted that the applicant credited its One-Time Inspection Program to confirm 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, if eddy current testing is not used, what inspection techniques will be used. By letter dated September 22, 2011, the staff issued RAI 3.3.2.2.4-1 requesting that the applicant clarify whether the non-regenerative heat exchangers will be included in the sample of components to be inspected. The staff also asked the applicant to provide justification as to why eddy current testing is not used and explain how visual inspection will detect cracking in the heat exchanger tubes.

In its response dated November 21, 2011, the applicant stated that although the non-regenerative heat exchangers are included in the material-environment component population in the One-Time Inspection Program, the heat exchanger tubes may not be selected for inspection. However, the applicant revised LRA Section 3.3.2.2.4.1 to include eddy current inspection of the tubes in one of the non-regenerative heat exchangers as part of the One-Time Inspection Program and stated that the LRA Basis Document AMP XI.M32, "One-Time Inspection Program," "scope of program" element, will be revised to reflect this requirement.

In its review of the applicant's response, the staff agreed that the above change addressed the technical concerns described in RAI 3.3.2.2.4-1; however, it was not clear to the staff how this apparent enhancement to the One-Time Inspection Program would be captured in the CLB. By letter dated February 8, 2012, the staff issued RAI 3.3.2.2.4-1a requesting that the applicant revise LRA Section A.1.16 for the One-Time Inspection Program to include a description of the eddy current testing of non-regenerative heat exchanger tubes or to provide another licensing basis document to comparably accomplish this commitment. In its response dated February 27, 2012, the applicant revised LRA Section A.1.16 and Section B2.1.16 to include the following statement: "The sample population includes eddy current testing of the tubes in one non-regenerative heat exchanger." The staff finds this response acceptable because the supplement to the UFSAR for the One-Time Inspection Program describes the eddy current testing of non-regenerative heat exchanger tubes, which becomes part of the CLB.

Based on the programs identified and the responses to RAI 3.3.2.2.4-1 and RAI 3.3.2.2.4-1a, the staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.3.2.2.4, item 1. For those items that apply to LRA Section 3.3.2.2.4, item 1, 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).

Item 2. LRA Section 3.3.2.2.4, item 2, associated with LRA Table 3.3.1, item 3.3.1.8, addresses cracking due to SCC and cyclic loading in stainless steel regenerative heat exchanger components exposed to treated borated water greater than 60 °C (140 °F). The criteria in SRP-LR Section 3.3.2.2.4, item 2, state that cracking due to SCC and cyclic loading may occur in stainless steel regenerative heat exchanger components exposed to treated borated water greater than 60 °C (140 °F). The SRP-LR also states that the existing AMP monitors and controls primary water chemistry to manage cracking due to SCC; however, since these controls do not preclude cracking, the SRP-LR recommends that the effectiveness of the 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 the Water Chemistry and the One-Time Inspection programs manage cracking due to SCC and cyclic loading for stainless steel heat exchangers exposed to treated borated water. The applicant further stated that the one-time inspection will include selected components at susceptible locations.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection programs are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.4, respectively. In its review of components associated with item 3.3.1.8, the staff finds that the applicant has met the further evaluation criteria and 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. In addition, the staff finds that the One-Time Inspection Program will confirm 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 determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.3.2.2.4, item 2. For those items that apply to LRA Section 3.2.2.2.4, item 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).

Item 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 in the PWR CVCS exposed to treated borated water, which will be managed for cracking due to SCC and cyclic loading by the Water Chemistry Program and One-Time Inspection Program. The criteria in SRP-LR Section 3.3.2.2.4, item 3, state that cracking due to SCC and cyclic loading could occur for the stainless steel pump casings of PWR high-pressure pumps in the CVCS. The SRP-LR also states that the existing AMP relies on monitoring and control of primary water chemistry to manage the aging effect. The SRP-LR further states that control of water chemistry does not preclude cracking due to SCC and cyclic loading; therefore, the effectiveness of the Water Chemistry Control Program should be confirmed to ensure that cracking does not occur. The GALL Report recommends that a plant-specific AMP be evaluated to confirm the absence of cracking due to SCC and cyclic loading, and to ensure that these aging effects are adequately managed. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Water Chemistry Program and the One-Time Inspection Program manage cracking due to SCC and cyclic loading for stainless steel pump casings exposed to treated borated water. LRA Section B2.1.16 states that the One-Time Inspection Program conducts one-time inspections of plant system piping and components to confirm the effectiveness of the Water Chemistry Program.

The staff's evaluations of the applicant's Water Chemistry Program and the One-Time Inspection Program are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.4, respectively. The staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the Water Chemistry Program and One-Time Inspection Program is acceptable because (a) the Water Chemistry Program limits the concentration of chemical species known to cause SCC and controls the dissolved oxygen levels to minimize the environmental effect on cracking; and (b) the One-Time Inspection Program includes a one-time inspection of selected components to confirm the effectiveness of the Water Chemistry Program and the absence of cracking so that it is ensured to adequately manage cracking due to SCC and cyclic loading of these components.

Based on the programs identified, the staff concludes that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.3.2.2.4, item 3. For those items that apply to LRA Section 3.3.2.2.4.3, the staff determines 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).

Item 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 cyclic loading and SCC 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 in-scope high-strength steel closure bolting exposed to air with steam or water leakage in the CVCS. The staff reviewed LRA Sections 2.3.3 and 3.3, and the UFSAR, and finds that no in-scope high-strength steel closure bolting exposed to air with steam or water leakage are present in the auxiliary systems.

3.3.2.2.5 Hardening and Loss of Strength Due to Elastomer Degradation

Item 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 the plant indoor air (uncontrolled) and ventilation atmosphere environments, which will be managed for hardening and loss of strength due to elastomer degradation by the External Surfaces Monitoring and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting programs. The criteria in SRP-LR Section 3.3.2.2.5, item 1, states that hardening and loss of strength due to elastomer degradation could occur for elastomeric seals and components associated with 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 External Surfaces Monitoring and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting programs are adequate to manage the aging effects of these components. The staff noted that based on a review of LRA Table 3.0-1, the applicant's definitions of plant indoor air and ventilation atmosphere are consistent with the GALL Report, Table IX.D, definition of air-indoor uncontrolled in regard to this component, material, and environment combination.

The staff's evaluations of the applicant's External Surfaces Monitoring and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.2.18, respectively. In its review of components associated with item 3.3.1.11, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the External Surfaces Monitoring and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components programs is acceptable for the following reasons:

- The programs provide for visual inspections of the internal surfaces during component surveillances or during periodic, predictive, and corrective maintenance activities when the systems are opened and the surfaces made accessible for visual inspection. The programs provide for visual inspections of the external surfaces during periodic system inspections and walkdowns.
- The plant indoor air and ventilation atmosphere are similar enough in temperature, and the flexible connectors and hoses are configured such that periodic external inspections could detect aging effects on the external or internal surfaces.
- When appropriate for the component configuration and material, physical manipulation will be used to augment visual inspection to confirm the absence of elastomer hardening and loss of strength.

As amended by its response to RAI SBPB-2-2, dated December 15, 2011, reactor makeup water storage tank floating elastomeric seals exposed to a plant indoor air environment, which will be managed for hardening and loss of strength, were added to Table 3.3.2-5. The AMR item cites item 3.3.1.11 and generic note E, and credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effect. The GALL Report, Revision 2, recommends GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"; however, the seal is located on the inside of a tank and, therefore, GALL Report item EP-58 recommends GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," 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 3.0.3.2.18. The staff noted that, in its response, the applicant stated that the inspections for this seal look for thinning along the sides and at seams, seam adhesion, seam flotation, and condensation buildup on the top of the seals. The applicant also stated that the inspection manipulates the seals to inspect for elastomer hardening or other changes in mechanical properties. The staff also noted that the applicant revised LRA Section B2.1.22 to state that the first inspection of the seals will be conducted within 5 years prior to the period of extended operation with followup inspections every 5 years thereafter. Based on its review of components associated with item 3.3.1.11, for which the applicant cited generic note E, 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:

- Visual inspections, augmented by physical manipulation of the material, will be conducted every 5 years.
- Visual inspections, augmented by physical manipulation of the material, are capable of detecting hardening and loss of strength in elastomeric materials.
- The inspections, conducted within 5 years prior to the period of extended operation with followup inspections every 5 years thereafter, are at a sufficient interval to detect aging.

Based on the programs identified, the staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.3.2.2.5, item 1. For those items associated with LRA Section 3.3.2.2.5, item 1, 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).

Item 2. LRA Section 3.3.2.2.5.2, associated with LRA Table 3.3.1, item 3.3.1.12, addresses hardening and loss of strength in elastomer lined components exposed to treated borated water in the spent fuel pool cooling and cleanup system. The applicant stated that this item is not applicable because there are no steel with elastomer lining components exposed to treated or treated borated water in the spent fuel pool cooling and cleanup system. The staff reviewed LRA Sections 2.3.3, 3.3, and the UFSAR, and finds that no in-scope steel piping with elastomer lining exposed to treated borated water is present in the spent fuel pool cooing system.

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, associated with LRA Table 3.3.1, item 3.3.1.13, addresses reduction of neutron-absorbing capacity and loss of material due to general corrosion in Boral and boron steel spent fuel storage racks neutron-absorbing sheets exposed to treated water or treated borated water. The applicant stated that this item is not applicable because STP does not employ Boral or boron steel in spent fuel storage racks to maintain subcriticality. The applicant stated that soluble boron is used in the spent fuel pool to provide criticality safety margin by maintaining an effective neutron multiplication factor (k_{eff}) less than 0.95, including uncertainties, tolerances, and accident conditions. The staff reviewed LRA Sections 2.3.3 and 3.3, and the TS, and finds that no in-scope Boral or boron steel spent fuel storage rack neutron-absorbing sheets exposed to treated water or treated borated are present in the system.

3.3.2.2.7 Loss of Material Due to General, Pitting, and Crevice Corrosion

Item 1. LRA Section 3.3.2.2.7.1 and Table 3.3.1, items 3.3.1.14, 3.3.1.15, and 3.3.1.16, address loss of material due to general, pitting, and crevice corrosion that may occur in piping, piping components, and piping elements exposed to lubricating oil. The applicant stated that these items were consistent with the GALL Report and referenced its Lubricating Oil Analysis and One-Time Inspection programs for managing the effects of aging. The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection programs are documented in SER Sections 3.0.3.2.19 and 3.0.3.1.4, respectively.

In its review of components associated with Table 3.3.1, items 3.3.1.14, 3.3.1.15, and 3.3.1.16, the staff finds that the applicant has met the further evaluation criteria and the applicant's proposal to manage aging using the Lubricating Oil Analysis and One-Time Inspection programs is acceptable because 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 selected components at susceptible locations where contaminants such as water could accumulate, which is also consistent with the GALL Report.

Based on the programs identified, the staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.3.2.2.7, item 1. For those items associated with LRA Section 3.3.2.2.7.1, 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).

Item 2. LRA Section 3.3.2.2.7.2 and Table 3.3.1, item 3.3.1.17, are applicable to BWRs only; therefore, they are not applicable to STP. This information is provided in SER Section 3.3.2.1.1.

Item 3. LRA Section 3.3.2.2.7.3, associated with LRA Table 3.3.1, item 3.3.1.18, addresses stainless steel and steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust, which will be 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 Program. The criteria in SRP-LR Revision 1, Section 3.3.2.2.7, item 3, states that loss of material due to general (steel only) pitting and crevice corrosion could occur for steel and stainless steel diesel exhaust piping components exposed to diesel exhaust. The SRP-LR also states that the acceptance criteria described in Branch Technical Position RLSB-1 should be used to ensure that a plant-specific AMP will adequately manage this aging effect. In addition, the equivalent item (3.3.1-88) in SRP-LR, Revision 2, states that GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," which recommends periodic inspections, is capable of ensuring that the aging effect is adequately managed. The applicant addressed the further evaluation criteria of the SRP-LR by stating that loss of material due to general, pitting, and crevice corrosion for carbon steel internal surfaces will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Program is documented in SER Section 3.0.3.2.18. The staff noted that the applicant's AMP uses visual inspections for loss of material performed by qualified personnel during periodic, predictive, and corrective maintenance activities and surveillance testing and includes inspection of steel and stainless steel components. The staff also noted that, although not specified in LRA Section 3.3.2.2.7.3, the AMR items associated with LRA Table 3.3.1, item 3.3.1.18, included both carbon steel and stainless steel components. The staff further noted that the program also includes supplemental inspections with locations and intervals based on the likelihood of degradation and on operating experience. During its review of components associated with item 3.3.1.18, the staff finds that the applicant meets the further evaluation criteria, and the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Program is acceptable because the applicant's program includes periodic visual inspections, which provide ongoing opportunities capable of detecting loss of material due to corrosion of steel and stainless steel components exposed to diesel exhaust.

Based on the program identified, the staff determines that the applicant's program meets the further evaluation criteria of SRP-LR, Section 3.3.2.2.7, item 3. For those items associated with LRA Section 3.3.2.2.7.3, 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).

3.3.2.2.8 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion

LRA Section 3.3.2.2.8, associated with LRA Table 3.3.1, item 3.3.1.19, addresses steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil, which will be managed for loss of material to general, pitting, and crevice corrosion, and MIC. The criteria in 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 SRP-LR also states that 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 applicant addressed the further evaluation criteria of the SRP-LR by stating that the Buried Piping and Tanks Inspection Program manages the loss of material due to general, pitting, crevice, and MIC for the carbon steel (including cast iron and ductile iron) external surfaces of buried components.

The staff's evaluation of the applicant's Buried Piping and Tanks Inspection Program is documented in SER Section 3.0.3.2.14. The staff noted that the program proposes to manage loss of material of buried piping and piping components through opportunistic and directed inspections. The program also includes preventive and mitigative actions to ensure the piping and components are coated, backfilled, and cathodically protected. If during the inspections, adverse indications (e.g., leaks, material thickness less than minimum, and general or local degradation of coatings that exposes the base material) that fail to meet the acceptance criteria are discovered, corrective actions for the repair or replacement of the affected component are required. The staff noted that the applicant did not address the second criterion in the SRP-LR, that is, the effectiveness of the Buried Piping and Tanks Inspection Program should be confirmed to evaluate an applicant's inspection frequency and operating experience. However, SRP-LR, Revision 2, and the GALL Report, Revision 2, have removed this recommendation; therefore, the applicant's proposal is in accordance with the current staff position. 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 because the program will use directed inspections or suitable alternative (hydrostatic test or visual inspection of the internal surface) to determine if a loss of material is occurring. In addition, the program contains corrective actions that include repair or replacement if acceptance criteria are not met.

Based on the program identified, the staff determines that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.3.2.2.8. For those items associated with LRA Section 3.3.2.2.8, 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).

3.3.2.2.9 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion and Fouling

Item 1. LRA Section 3.3.2.2.9.1 and Table 3.3.1, item 3.3.1.20, address loss of material due to general, pitting, and crevice corrosion, MIC, and fouling in applicable diesel generator system steel piping, piping components, and piping elements exposed to fuel oil. The applicant stated that this item is consistent with the GALL Report and that the Fuel Oil Chemistry and One-Time Inspection programs will be used to manage aging for these components. The staff's evaluations of the applicant's Fuel Oil Chemistry and One-Time Inspection programs are documented in SER Sections 3.0.3.2.11 and 3.0.3.1.4, respectively.

In its review of components associated with item 3.3.1.20, the staff finds that the applicant meets the further evaluation criteria, and the applicant's proposal to manage aging using the Fuel Oil Chemistry and One-Time Inspection programs is acceptable because the Fuel Oil Chemistry Program was determined to be consistent with the GALL Report, and the staff confirmed that the One-Time Inspection Program will be used to examine selected components at susceptible locations where contaminants such as water could accumulate, which is also consistent with the GALL Report.

Based on the programs identified, the staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.3.2.2.9, item 1. For those items associated with LRA Section 3.3.2.2.9.1, 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).

Item 2. LRA Section 3.3.2.2.9.2 and Table 3.3.1, item 3.3.1.21, address loss of material due to general, pitting, and crevice corrosion, and MIC that may occur in heat exchanger components exposed to lubricating oil. The applicant stated that this item is consistent with the GALL Report, and that the Lubricating Oil Analysis and One-Time Inspection programs will be used to manage aging for these components. The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection programs are documented in SER Sections 3.0.3.2.19 and 3.0.3.1.4, respectively.

In its review of components associated with item 3.2.1.21, the staff finds that the applicant meets the further evaluation criteria, and the applicant's proposal to manage aging using the Lubricating Oil Analysis and One-Time Inspection programs is acceptable because the Lubricating Oil Analysis Program was determined to be consistent with the GALL Report, and the staff confirmed that the One-Time Inspection Program will be used to examine selected components at susceptible locations where contaminants such as water could accumulate, which is also consistent with the GALL Report.

Based on the programs identified, the staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.3.2.2.9, item 2. For those items associated with LRA Section 3.3.2.2.9.2, 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).

3.3.2.2.10 Loss of Material Due to Pitting and Crevice Corrosion

Item 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, piping components, and piping elements (after lining/cladding degradation) with elastomer lining or stainless steel cladding exposed to treated water or treated borated water. The applicant stated that this item is not applicable because there are no steel with elastomer lining or steel with stainless steel cladding components exposed to treated or treated borated water in the spent fuel pool cooing system. The staff noted that although the applicant claimed non-applicability based on having no in-scope steel piping with elastomer lining or stainless steel cladding exposed to treated or treated borated water in the spent fuel pool cooing system, SRP-LR Section 3.3.2.2.10, item 1, is applicable to all auxiliary systems. The staff reviewed LRA Sections 2.3.3 and 3.3, and the

UFSAR, and finds that no in-scope steel piping with elastomer lining or stainless steel cladding exposed to treated or treated borated water is present in the auxiliary systems.

Item 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 aluminum piping, piping components, and piping elements and stainless steel and steel with stainless steel cladding heat exchanger components exposed to treated water. The applicant stated that this item is not applicable because loss of material for these components is only applicable to BWR plants. The staff noted that the LRA contains stainless steel piping exposed to demineralized water in the auxiliary systems; however, the applicant chose to manage those components with LRA Table 3.4-1, item 3.4.1.16, which manages loss of material due to pitting and crevice corrosion with the Water Chemistry and One-Time Inspection programs, which is consistent with the updated staff guidance in the GALL Report, Revision 2. Therefore, the staff finds the applicant's determination of non-applicability for stainless steel piping acceptable. The staff reviewed LRA Sections 2.3.3 and 3.3, and the UFSAR, and finds that no in-scope aluminum piping or stainless steel and steel with stainless steel cladding heat exchanger components exposed to treated water are present in the auxiliary systems.

Item 3. LRA Section 3.3.2.2.10.3, which is associated with LRA Table 3.3.1, item 3.3.1.25, addresses copper alloy HVAC piping, piping components, and piping elements exposed to condensation, which will be managed for loss of material due to pitting and crevice corrosion by the External Surfaces Monitoring Program or by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Program. The criteria in SRP-LR Section 3.3.2.2.10, item 3, state that loss of material due to pitting and crevice corrosion could occur for copper-alloy piping, piping components, and piping elements exposed to condensation (external). 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 stating that the External Surfaces Monitoring Program manages loss of material due to pitting and crevice corrosion for the external surfaces of copper alloy components exposed to plant indoor air, and the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program manages loss of material due to pitting and crevice corrosion for the internal surfaces of copper alloy components exposed to a ventilation atmosphere.

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 3.0.3.2.16 and 3.0.3.2.18, respectively. The staff noted that the applicant's External Surfaces Monitoring Program and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program both include visual inspections for loss of material performed by qualified personnel. The staff also noted that the External Surfaces Monitoring Program's visual inspections will be implemented during system inspections and walkdowns, and the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program's visual inspections will be implemented during periodic maintenance, predictive maintenance, surveillance testing, and corrective maintenance activities. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program also includes supplemental inspections not performed concurrently with other planned work activities that are based on assessments of the likelihood of degradation and on current industry and plant-specific operating experience. The staff further noted that each program includes inspections of steel, stainless steel, aluminum, copper alloy, and other metallic and non-metallic components.

Based on its review of components associated with item 3.3.1.25, the staff finds that the applicant meets the further evaluation criteria, and the applicant's proposal to manage aging using the External Surfaces Monitoring Program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is acceptable for the following reasons:

- The applicant's programs include visual inspections that are capable of detecting loss of material due to pitting and crevice corrosion in copper alloy components.
- The applicant's programs include acceptance criteria and provisions for corrective actions if unacceptable loss of material is detected.
- As documented in the GALL Report, Revision 2, the staff has determined that a program including periodic visual inspections, acceptance criteria, and corrective actions is acceptable for managing loss of material due to pitting and crevice corrosion in copper alloy components exposed to condensation.

Based on the programs identified, the staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.3.2.2.10, item 3. For those items associated with LRA Section 3.3.2.2.10.3, 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).

Item 4. LRA Section 3.3.2.2.10.4, associated with LRA Table 3.3.1, item 3.3.1.26, addresses loss of material due to pitting and crevice corrosion that may occur in copper-alloy piping, piping components, and piping elements exposed to lubricating oil. The SRP-LR criteria state that because control of lubricating oil contaminants may not always have been adequate to preclude corrosion, the effectiveness of lubricating oil contaminant control should be confirmed to ensure that corrosion does not occur. The applicant stated that this item is consistent with the GALL Report and that it will use the Lubricating Oil Analysis and One-Time Inspection programs to manage aging for these components. The applicant also stated that its One-Time Inspection Program will include locations where contaminants could accumulate. The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection programs are documented in SER Sections 3.0.3.2.19 and 3.0.3.1.4, respectively.

Based on its review of components associated with item 3.3.1.26, the staff finds that the applicant meets the further evaluation criteria, and the applicant's proposal to manage aging using the Lubricating Oil Analysis and One-Time Inspection programs is acceptable because the Lubricating Oil Analysis Program was determined to be consistent with the GALL Report, and the staff confirmed that the One-Time Inspection Program will be used to examine selected components at susceptible locations where contaminants such as water could accumulate, which is also consistent with the GALL Report.

Based on the programs identified, the staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.3.2.2.10, item 4. For those items associated with LRA Section 3.3.2.2.10.4, 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).

Item 5. LRA Section 3.3.2.2.10.5, associated with LRA Table 3.3.1, item 3.3.1.27, addresses stainless steel HVAC ducting and components and aluminum HVAC piping, piping components, and piping elements exposed to condensation. As described in the applicant's response to RAI 3.0-1a by letter dated February 27, 2012, the loss of material from pitting and crevice corrosion for stainless steel and aluminum internal surfaces exposed to ventilation atmosphere and condensation will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Program, and the stainless steel and aluminum external surfaces exposed to plant indoor air and condensation will be managed for loss of material from pitting and crevice corrosion by the External Surfaces Monitoring Program. The criteria in SRP-LR Section 3.3.2.2.10, item 5, state 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 stating that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program manages the loss of material from pitting and crevice corrosion for stainless steel and aluminum internal surfaces exposed to ventilation atmosphere and condensation, and the External Surfaces Monitoring Program manages the loss of material from pitting and crevice corrosion for stainless steel and aluminum external surfaces exposed to indoor air and condensation.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program and External Surfaces Monitoring Program are documented in SER Section 3.0.3.2.18, and 3.0.3.2.16, respectively. The staff noted that the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and External Surfaces Monitoring programs use visual inspections for loss of material performed by qualified personnel during periodic maintenance, predictive maintenance, surveillance testing, and corrective maintenance activities and includes inspection of steel, stainless steel, and aluminum components. The staff further noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program also includes supplemental inspections not performed concurrently with other planned work activities and that the supplemental inspections are based on assessments of likelihood of degradation and on current industry and plant-specific operating experience.

Based on its review of components associated with item 3.3.1.27, the staff finds that the applicant meets the further evaluation criteria, and the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and External Surfaces Monitoring programs is acceptable for the following reasons:

- The applicant's programs use periodic visual inspections to detect loss of material due to pitting and crevice corrosion in stainless steel and aluminum components.
- The applicant's programs include acceptance criteria and provisions for corrective actions if unacceptable loss of material is detected.
- As documented in the GALL Report, Revision 2, the staff has determined that a program including periodic visual inspections, acceptance criteria, and corrective actions is acceptable for managing loss of material due to pitting and crevice corrosion in stainless steel and aluminum HVAC components exposed to condensation, and it is consistent with the criteria in SRP-LR Section 3.3.2.2.10, item 5.

Based on the program identified, the staff determines that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.3.2.2.10, item 5. For those items associated with

LRA Section 3.3.2.2.10.5, 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).

Item 6. LRA Section 3.3.2.2.10.6, which is associated with LRA Table 3.3.1, item 3.3.1.28, addresses copper alloy fire protection piping, piping components, and piping elements exposed to internal condensation, which will be managed for loss of material due to pitting and crevice corrosion by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Program. The criteria in SRP-LR Section 3.3.2.2.10, item 6, state that loss of material due to pitting and crevice corrosion could occur for copper alloy fire protection system piping, piping components, and piping elements exposed to internal condensation. The SRP-LR also states that 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 stating that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program manages the loss of material from pitting and crevice corrosion for copper alloy internal surfaces exposed to internal condensation and moisture. As amended by letter dated June 3, 2014, LRA Table 3.3.1, item 3.3.1.28 is only cited for copper alloy valves in the compressed air system. Copper alloy valves in the fire protection system that previously cited the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Program now cite the Fire Water System Program. The staff's evaluation of these changes is documented in SER Section 3.3.2.3.17 below.

Based on the programs identified, the staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.3.2.2.10, item 6. For those items associated with LRA Section 3.3.2.2.10.6, 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).

Item 7. LRA Section 3.3.2.2.10.7, associated with LRA Table 3.3.1, item 3.3.1.29, addresses loss of material due to pitting and crevice corrosion in stainless steel piping, piping components, and piping elements exposed to soil. The applicant stated that this item is not applicable because the auxiliary systems do not contain any in-scope stainless steel piping, piping components, or piping elements that are exposed to soil. The staff reviewed LRA Sections 2.3.3 and 3.3, and the applicant's UFSAR, and confirmed that no in-scope stainless steel piping, piping components, and piping elements exposed to soil are present in the auxiliary systems.

Item 8. LRA Section 3.3.2.2.10.8 and Table 3.3.1, item 3.3.1.30, address 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. This item is applicable to BWRs only; therefore, it is not applicable to STP. Evaluation of this items is described in SER Section 3.3.2.1.1.

3.3.2.2.11 Loss of Material Due to Pitting, Crevice, and Galvanic Corrosion

LRA Section 3.3.2.2.11 and Table 3.3.1, item 3.3.1.31, are applicable to BWRs only. Therefore, as stated in SER Section 3.3.2.1.1, this item is not applicable to STP.

3.3.2.2.12 Loss of Material Due to Pitting, Crevice, and Microbiologically-Influenced Corrosion

Item 1. LRA Section 3.3.2.2.12.1 is associated with Table 3.3.1, item 3.3.1.32, and addresses loss of material due to pitting, crevice corrosion, and MIC in stainless steel and copper-alloy piping, piping components, and piping elements exposed to fuel oil. The applicant stated that this item is consistent with the GALL Report and that the Fuel Oil Chemistry and One-Time Inspection programs will be used to manage aging for these components. The staff's evaluations of the applicant's Fuel Oil Chemistry and One-Time Inspection programs are documented in SER Sections 3.0.3.2.11 and 3.0.3.1.4, respectively.

During its review of components associated with item 3.3.1.32, the staff finds that the applicant meets the further evaluation criteria, and the applicant's proposal to manage aging using the Fuel Oil Chemistry and One-Time Inspection programs is acceptable because the Fuel Oil Chemistry Program was determined to be consistent with the GALL Report, and the staff confirmed that the One-Time Inspection Program will be used to examine selected components at susceptible locations where contaminants such as water could accumulate, which is also consistent with the GALL Report.

Based on the programs identified, the staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.3.2.2.12, item 1. For those items associated with LRA Section 3.3.2.2.12.1, 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).

Item 2. LRA Section 3.3.2.2.12.2 is associated with Table 3.3.1, item 3.3.1.33, and addresses loss of material due to pitting, crevice corrosion, and MIC that may occur in stainless steel piping, piping components, and piping elements exposed to lubricating oil. The applicant stated that this item is consistent with the GALL Report and that the Lubricating Oil Analysis and One-Time Inspection programs will be used to manage aging for these components. The applicant also stated that aging effects for the RCP lube oil collection system will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection programs are documented in SER Sections 3.0.3.2.19 and 3.0.3.1.4, respectively. However, the staff determined that additional information was needed concerning the applicant's use of the Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging for the RCP lube oil collection system. In RAI 3.3.2.2.12.2-1, dated April 26, 2012, the staff requested that the applicant justify the use of this program to manage loss of material due to pitting, crevice corrosion, and MIC for stainless steel components exposed to lubricating oil in the RCP lube oil collection system.

By letter dated May 3, 2012, the applicant responded that LRA Section 3.3.2.2.12.2 incorrectly states that the loss of material due to pitting, crevice corrosion, and MIC for stainless steel components exposed to lubricating oil in the RCP lube oil collection system is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. Instead, aging management is provided by the Lubricating Oil Analysis and One-Time Inspection programs. In addition, the applicant revised LRA Section 3.3.2.2.12.2 to delete the discussion on the RCP lube oil collection system being managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program.

The staff reviewed this response and finds it acceptable because the revision to LRA Section 3.3.2.2.12.2 makes it consistent with the recommendations found in GALL Report AMP XI.M39, “Lubricating Oil Analysis.” The staff’s concern described in RAI 3.3.2.2.12.2-1 is resolved.

During its review of components associated with LRA Table 3.3.1, item 3.3.1.33, the staff finds that the applicant has met the further evaluation criteria, and the applicant’s proposal to manage aging using the Lubricating Oil Analysis and One-Time Inspection programs is acceptable because the Lubricating Oil Analysis Program was determined to be consistent with the GALL Report, and the staff confirmed that the One-Time Inspection Program will be used to examine selected components at susceptible locations where contaminants such as water could accumulate, which is also consistent with the GALL Report.

Based on the programs identified and the applicant’s response to RAI 3.3.2.2.12.2-1, the staff determines that the applicant’s programs meet the further evaluation criteria of SRP-LR Section 3.3.2.2.12, item 2. For those items associated with LRA Section 3.3.2.2.12.2, 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 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 plant indoor uncontrolled air (internal or external), which will be managed for loss of material due to wear by the External Surfaces Monitoring and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting programs. The criteria in SRP-LR Section 3.3.2.2.13 state that loss of material due to wear could occur for elastomer seals and components exposed to indoor uncontrolled air (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 External Surfaces Monitoring Program manages the loss of material due to wear from elastomer degradation for elastomer external surfaces exposed to plant indoor air (uncontrolled) in locations where relative motion of adjacent surfaces is possible. The applicant also stated that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program manages the loss of material due to wear from elastomer degradation for elastomer internal surfaces exposed to plant indoor air (internal) and ventilation atmosphere in locations where relative motion of adjacent surfaces is possible.

The staff’s evaluations of the applicant’s External Surfaces Monitoring and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components programs are documented in SER Sections 3.0.3.2.16 and 3.0.3.2.18, respectively. In its review of components associated with item 3.3.1.34, the staff finds that the applicant has met the further evaluation criteria, and the applicant’s proposal to manage aging using the External Surfaces Monitoring and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components programs is acceptable because the programs provide for visual inspections of internal surfaces during component surveillances or during periodic, predictive, and corrective maintenance activities when the systems are opened and the surfaces made accessible for visual inspection and the external surfaces during periodic system inspections and walkdowns. Additionally, when appropriate for the component, configuration, and material, physical manipulation will be used to augment visual inspection to confirm the absence of elastomer loss of material due to wear.

Based on the programs identified, the staff determined that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.3.2.2.13. For those items associated with LRA Section 3.3.2.2.13, 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).

3.3.2.2.14 Loss of Material Due to Cladding Breach

LRA Section 3.3.2.2.14 is associated with LRA Table 3.3.1, item 3.3.1.35, and addresses loss of material due to cladding breach in steel with stainless steel cladding pumps exposed to treated borated water, as described in NRC IN 94-63, "Boric Acid Corrosion of Charging Pump Casings Caused by Cladding Cracks." This IN describes a cladding breach of the centrifugal charging pumps at North Anna Power Station. The applicant stated that this item is not applicable because the CVCS for STP does not contain steel with stainless steel cladding pumps exposed to treated borated water. The staff reviewed LRA Sections 2.3.3 and 3.3, and the UFSAR, and finds that no in-scope pumps comprising steel with stainless steel cladding exposed to treated borated water are present in the auxiliary systems.

3.3.2.2.15 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's QA Program.

3.3.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.3.2-1 through 3.3.2-28, the staff reviewed additional details of AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.3.2-1 through 3.3.2-28, the applicant indicated, via notes F through 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 whether the applicant had 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 as required by 10 CFR 54.21(a)(3).

3.3.2.3.1 Auxiliary Systems—Summary of Aging Management Evaluation—Fuel Handling System—LRA Table 3.3.2-1

Closure Bolting Stainless Steel Exposed to Treated Borated Water. In LRA Table 3.3.2-1, the applicant stated that the stainless steel closure bolting exposed to treated borated water will be managed for loss of preload by the Bolting Integrity Program. The AMR items cite generic note H. Items associated with closure bolting cite plant-specific note 1, which states that loss of preload is conservatively applied for all closure bolting.

The staff noted that this material and environment combination was not identified in the GALL Report, Revision 1; however, items EP-120 and AP-265 in the GALL Report, Revision 2, address stainless steel closure bolting exposed to treated borated water and recommends GALL Report AMP XI.M18, “Bolting Integrity,” to manage loss of preload. The applicant addressed the GALL Report identified aging effects, cracking, and loss of material for this component, material, and environment combination in AMR items in LRA Table 3.3.2-1, plant-specific note 2.

The staff’s evaluation of the applicant’s Bolting Integrity Program is documented in SER Section 3.0.3.2.5. The staff finds the applicant’s proposal to manage aging using the Bolting Integrity Program acceptable because it includes bolting assembly and maintenance controls such as application of appropriate gasket alignment, torque, lubricants, and preload, and it inspects bolted connections to ensure detection of leakage occurs before the leakage becomes excessive.

Conclusion. 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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.2 Auxiliary Systems—Summary of Aging Management Evaluation—Spent Fuel Pool Cooling and Cleanup System—LRA Table 3.3.2-2

Closure Bolting Stainless Steel Exposed to Plant Indoor Air. In LRA Tables 3.3.2-2, 3.3.2-4, 3.3.2-5, 3.3.2-6, 3.3.2-7, 3.3.2-10, 3.3.2-14, 3.3.2-16, 3.3.2-20, 3.3.2-22, 3.3.2-23, 3.3.2-24, 3.3.2-25, and 3.3.2-27, the applicant stated that the stainless steel closure bolting exposed to plant indoor air will be managed for loss of preload by the Bolting Integrity Program. The AMR items cite generic note H. Items associated with closure bolting cite plant-specific note 1, which states that loss of preload is conservatively applied for all closure bolting.

The staff noted that this material and environment combination was not identified in the GALL Report, Revision 1; however, several items (e.g., RP-46, AP-124) in the GALL Report, Revision 2, address stainless steel closure bolting exposed to air-indoor uncontrolled (which is consistent with the applicant’s plant indoor air environment), and recommend the GALL Report AMP XI.M18, “Bolting Integrity,” to manage loss of preload. The staff noted that, in conjunction with managing the loss of preload aging effect, the closure bolting will also be managed for loss of material by the Bolting Integrity Program.

The staff’s evaluation of the applicant’s Bolting Integrity Program is documented in SER Section 3.0.3.2.5. The staff finds the applicant’s proposal to manage loss of preload using the Bolting Integrity Program acceptable because it includes bolting assembly and maintenance controls such as application of appropriate gasket alignment, torque, lubricants, and preload, and it inspects for leaking bolted connections to ensure detection of leakage occurs before the leakage becomes excessive.

Heat Exchanger (Spent Fuel Pool) Stainless Steel Exposed to Treated Borated Water (Internal). In LRA Table 3.3.2-2, the applicant stated that the stainless steel heat exchanger (spent fuel pool) exposed to treated borated water (internal) will be managed for reduction of heat transfer by the Water Chemistry Program and One-Time Inspection Program. The AMR item cites generic note G. Items associated with stainless steel heat exchangers in LRA Table 3.3.2-2 cite plant-specific note 2, which states that "reduction in heat transfer due to fouling is a potential aging effect/mechanism for stainless steel heat exchanger components in treated borated water. This non-NUREG-1801 line is based upon the component, material, aging effects and aging management program combination of NUREG-1801, line V.A-16."

The staff noted that this material and environment combination is identified in the GALL Report, which addresses stainless steel and heat exchanger components and tubes exposed to treated borated water and recommends a TLAA to manage cumulative fatigue damage; however, the applicant has identified this additional aging effect. The applicant addressed the GALL Report identified aging effects for this component, material, and environment combination in LRA Section 3.3.2.2.1.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection programs are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.4, respectively. The staff finds the applicant's proposal to manage aging using the Water Chemistry Program acceptable because the Water Chemistry Program manages reduction of heat transfer by monitoring and controlling the chemical environment in the reactor coolant and related auxiliary systems within industry guidelines to mitigate fouling. Additionally, the One-Time Inspection Program confirms the effectiveness of the Water Chemistry Program by conducting one-time inspections using acceptance criteria consistent with the design and standards of ASME Code Section XI, as applicable, for the component.

Carbon Steel and Stainless Steel Piping Exposed to Treated Borated Water, Closed-Cycle Cooling Water, and Raw Water. In LRA Tables 3.3.2-2, 3.3.2-9, and 3.3.2-27, the applicant stated that the carbon steel and stainless steel piping exposed to treated borated water, CCCW, and raw water will be managed for wall thinning by the Flow-Accelerated Corrosion Program. The AMR items cite generic note H and were added in response to RAI 3.4.2.6-1, as discussed in SER Section 3.0.3.2.4.

The staff noted that these material and environment combinations are identified in the GALL Report, which addresses carbon steel and stainless steel piping exposed to treated borated water, closed-cycle water, and raw water, and recommends the Water Chemistry Program, the Closed-Cycle Cooling Water Program, and the Open-Cycle Cooling Water Program to manage loss of material; however, the applicant has identified the additional aging effect of wall thinning and the corresponding AMP as its Flow-Accelerated Corrosion Program. The applicant addressed the GALL Report identified aging effects for this component, material, and environment combination in AMR items in LRA Tables 3.3.2-2, 3.3.2-9, and 3.3.2-27.

The staff's evaluation of the applicant's Flow-Accelerated Corrosion Program is documented in SER Section 3.0.3.2.4. The staff noted that, in response to RAI B2.1.6-1a, the applicant revised the program to include aging management of wall thinning due to mechanisms other than flow-accelerated corrosion. The staff finds the applicant's proposal to manage aging using the

Flow-Accelerated Corrosion Program acceptable because the detection, monitoring, and acceptance criteria for the additional wall thinning mechanisms are the same as for flow-accelerated corrosion, and the program includes guidance for inspection and selection of components that are susceptible to wall thinning due to mechanisms other than flow-accelerated corrosion.

Conclusion. 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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.3 Auxiliary Systems—Summary of Aging Management Evaluation—Cranes and Hoists—LRA Table 3.3.2-3

The staff reviewed LRA Table 3.3.2-3, which summarizes the results of AMR evaluations for the containment spray system component groups.

The staff's review did not find any items indicating plant-specific notes F through 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 associated with notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.4 Auxiliary Systems—Summary of Aging Management Evaluation—Essential Cooling Water and ECW Screen Wash System—LRA Table 3.3.2-4

The staff's evaluation for stainless steel closure bolting exposed to plant indoor air that will be managed for loss of preload by the Bolting Integrity Program and cites generic note H is documented in SER Section 3.3.2.3.2.

Closure Bolting Copper Alloy Exposed to Plant Indoor Air. In LRA Table 3.3.2.4, the applicant stated that copper alloy closure bolting exposed to plant indoor air will be managed for loss of preload by the Bolting Integrity Program. The AMR item cites generic note F. Items associated with closure bolting cite plant-specific note 1, which states that loss of preload is conservatively applied for all closure bolting.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on GALL Report Revision 2, items AP-261 and SP-149, which state that loss of preload is the only aging effect for copper bolting exposed to any environment, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.5. The staff finds the applicant's proposal to manage loss of preload using the Bolting Integrity Program acceptable because it includes bolting assembly and maintenance controls such as application of appropriate gasket alignment, torque, lubricants, and preload, and it inspects bolted connections for leakage, to ensure detection of leakage occurs before the leakage becomes excessive.

Strainer Carbon Steel Clad with Copper-Nickel Exposed to Raw Water Internal. In LRA Table 3.3.2-4, the applicant stated that carbon steel clad with copper-nickel exposed to raw water will be managed for loss of material by the Open-Cycle Cooling Water System Program. The AMR item cites generic note F.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the GALL Report, which states copper-nickel alloys are resistant to SCC and selective leaching, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Open-Cycle Cooling Water System Program is documented in SER Section 3.0.3.2.6. The staff finds the applicant's proposal to manage aging using the Open-Cycle Cooling Water System Program acceptable because it includes surveillance and control techniques to manage aging effects caused by biofouling, corrosion, erosion, protective coating failures, and silting and includes periodic inspections to monitor aging effects.

Copper-Alloy Piping Exposed to a Buried Environment. In LRA Table 3.3.2-4, the applicant stated that copper alloy buried piping will be managed for loss of material 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 considered whether the aging effect proposed by the applicant constitutes all of the credible aging effects for this component, material, and environment description. As stated in the GALL Report, Revision 2 (item AP-174), copper alloy may be susceptible to loss of material due to pitting and crevice corrosion; for this reason, the GALL Report recommends use of the Buried and Underground Piping and Tanks Inspection Program to manage the effects of aging.

The staff's evaluation of the applicant's Buried Piping and Tanks Inspection Program is documented in SER Section 3.0.3.2.14. The staff noted that the program proposes to manage loss of material of buried piping and piping components through opportunistic and directed inspections. The program also includes preventive and mitigative actions to ensure the piping and components are coated, backfilled, and cathodically protected. The staff finds the applicant's proposal to manage loss of material using the Buried Piping and Tanks Inspection Program acceptable because the program will use directed inspections or suitable alternative to determine if a loss of material is occurring. In addition, the program contains corrective actions that include repair or replacement of the affected component if acceptance criteria are not met.

Copper Alloy (Greater than 8 Percent Aluminum) Piping Exposed to a Buried Environment. By letter dated June 16, 2011, the applicant amended LRA Table 3.3.2-4 and added an AMR item, which states that copper alloy (greater than 8 percent aluminum) buried piping will be managed for loss of material 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 considered whether the aging effect proposed by the applicant constitutes all of the credible aging effects for this component, material, and environment description. As stated in the GALL Report, Revision 2 (Table IX.C), copper alloy (greater than 8 percent aluminum) may also be susceptible to SCC and selective leaching. The staff noted that the applicant addressed loss of material due to selective leaching for this component, material, and environment combination in an AMR item in LRA Table 3.3.2-4 (added by an LRA amendment dated June 16, 2011), which will use the Selective Leaching of Aluminum Bronze Program to manage loss of material due to selective leaching. In accordance with the Metals Handbook, copper alloys greater than 8 percent aluminum may also be susceptible to SCC when exposed to ammonia or amines and tensile stress is present. The staff reviewed the UFSAR and the environmental report and noted that there are potential sources of ammonia or ammonia-like compounds in the vicinity of the STP site. The staff could not determine if the soil analysis performed as part of the Buried Piping and Tanks Inspection Program includes testing for the presence of ammonia or ammonia-like compounds. Therefore, by letter dated September 22, 2011, the staff issued RAI 3.3.2.3.4-1 requesting that the applicant describe what measures are taken to detect the presence or absence of ammonia in the soil near the copper alloy (greater than 8 percent aluminum) buried piping elements.

In its response dated October 15, 2011, the applicant stated that the closest industrial facility is 4.8 miles away, and there have been no industrial ammonia events detected at its plant site. The applicant also stated that there are no large concentrations of cattle within 5 miles of the plant site that could generate excessive detrimental gases or concentrated solid waste, and there is no runoff from adjacent land onto the plant site. In addition, the applicant performed a search of its corrective action database and did not identify any ammonia or ammonia-like compound spills or contaminations that affected onsite soil conditions. Therefore, the applicant concluded that there is no evidence to expect that the soil at its plant site would have elevated levels of ammonia or ammonia-like compounds.

The staff finds the applicant’s response acceptable because ammonia or amines are not present in the vicinity of the buried aluminum bronze piping such that SCC would be an aging effect of concern, which is supported by the applicant’s review of the corrective action database. As such, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination. The staff’s concern described in RAI 3.3.2.3.4-1 is resolved.

The staff’s evaluation of the applicant’s Buried Piping and Tanks Inspection Program is documented in SER Section 3.0.3.2.14. The staff noted that the program proposes to manage loss of material of buried piping and piping components through opportunistic and directed inspections. The program also includes preventive and mitigative actions to ensure the piping and components are coated, backfilled, and cathodically protected. The staff finds the applicant’s proposal to manage loss of material using the Buried Piping and Tanks Inspection Program acceptable because the program will use directed inspections or suitable alternative to determine if a loss of material is occurring. In addition, the program contains corrective actions that include repair or replacement of the affected component if acceptance criteria are not met.

<u>Copper Alloy (Greater than 8 Percent Aluminum) Piping (Welds) Exposed to a Buried Environment</u>. In LRA Table 3.3.2-4, as amended in letter dated June 16, 2011, the applicant stated that copper alloy (greater than 8 percent aluminum) piping exposed to an external buried environment will be managed for loss of material by the Selective Leaching of Aluminum Bronze Program. The AMR item cites generic note G. Items associated with copper alloy (greater than 8 percent aluminum) piping exposed to an external buried environment in this table cite plant-specific note 4, which states that “[t]he weld material used in this piping has an aluminum content of between 8.5–11%. This aging evaluation is applicable for the welds in the buried ECW piping which have the potential for greater than 8% aluminum and thus are considered susceptible to selective leaching.”

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noted that the applicant also addressed loss of material for this component, material, and environment combination in an AMR item in LRA Table 3.3.2-4, which will use the Buried Piping and Tanks Inspection Program to age manage loss of material (i.e., general, pitting, and crevice corrosion, and MIC). Based on its review of the GALL Report, item A-47, which states that copper alloy (greater than 15 percent Zn or greater than 8 percent aluminum) exposed to raw water (an environment equivalent to the buried environment) is susceptible to selective leaching, and item AP-45, which states that copper alloy exposed to raw water is susceptible to loss of material due to general, pitting, and crevice corrosion, and MIC, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Selective Leaching of Aluminum Bronze Program is documented in SER Section 3.0.3.3.3. Until OI 3.0.3.3.3-2 is resolved, the staff cannot complete its evaluation of this AMR item. The staff conducted a followup audit of the applicant's program and supporting documentation on February 29, 2012, and issued RAI B2.1.37-3 by letter dated April 12, 2012, to address the information required to close OI 3.0.3.3.3-2.

<u>Copper Alloy (Greater than 8 Percent Aluminum) Piping Exposed to Borated Water Leakage (External)</u>. In LRA Table 3.3.2-4, the applicant stated that copper alloy (greater than 8 percent aluminum) piping exposed to borated water leakage (external) will be managed for loss of material by the Boric Acid Corrosion Program. The AMR item cites generic note G.

The staff noted that, while the applicant cited generic note G, the borated water leakage environment is present in the GALL Report for this component and material. The staff also noted that LRA Table 3.0-1 aligns the LRA environment of borated water leakage with the GALL Report environment of air with borated water leakage. The staff further noted that GALL Report, Revision 2, item VII.I.AP-66, states that copper alloy greater than 15 percent Zn or 8 percent aluminum piping, piping components, and piping elements exposed to air with borated water leakage is managed for loss of material due to boric acid corrosion with GALL Report AMP XI.M10, "Boric Acid Corrosion." The staff finds that the applicant identified the appropriate aging effects, consistent with the GALL Report recommendation, for this component, material, and environment combination.

The staff's evaluation of the applicant's Boric Acid Corrosion Program is documented in SER Section 3.0.3.2.3. The staff finds the applicant's proposal to manage aging using the Boric Acid Corrosion program acceptable because the program includes periodic visual inspections for potential boric acid leakage and timely engineering evaluations and repair if leakage is detected, which are capable of identifying and repairing degradation prior to loss of intended functions.

<u>Copper Alloy (Aluminum Greater than 8 Percent) Piping Exposed to Raw Water</u>. In LRA Table 3.3.2-4, as revised in its response to RAI 4.7.3-2, dated March 5, 2012, the applicant stated there is a TLAA for copper alloy (aluminum greater than 8 percent) piping exposed to raw water that cites generic note H. The staff confirmed that there is a TLAA, as documented in LRA Section 4.7.3, for this component and material. The staff's evaluation of the TLAA for copper alloy (aluminum greater than 8 percent) piping in the ECW system is documented in SER Section 4.7.3.

<u>Carbon Steel Clad with Copper-Nickel Strainers Exposed to Plant Indoor Air</u>. In LRA Table 3.3.2-4 the applicant stated that carbon steel clad with copper-nickel strainers exposed to

plant indoor air (external) will be managed for loss of material by the External Surfaces Monitoring Program. The AMR item cites generic note F and also cites plant-specific note 2, which states that carbon steel clad with copper-nickel is not a material addressed in the GALL Report; however, the External Surfaces Monitoring Program manages the aging of the exterior carbon steel surfaces of this material that are exposed to plant indoor air (external), and the Open-Cycle Cooling Water Program manages the aging of the copper-nickel clad surfaces of this material that are exposed to raw water.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the GALL Report, which states carbon steel strainers exposed to plant indoor air are only susceptible to loss of material, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.16. The staff noted that the LRA clarifies that the exterior portion of the strainers is carbon steel exposed to plant indoor air (external), which is a material and environment combination that is within the scope of the External Surfaces Monitoring Program. The staff finds the applicant's proposal to manage aging using the External Surfaces Monitoring Program acceptable because the visual inspections and surveillance activities included in the AMP are adequate to detect loss of material on the external surface of carbon steel strainers prior to loss of intended function.

<u>Heat Exchanger Components Managed for Reduction of Heat Transfer</u>. Multiple tables in the LRA (Tables 3.3.2-4, 3.3.2-6, 3.3.2-7, 3.3.2-9 through -12, 3.3.2-14, 3.3.2-16, 3.3.2-19, and 3.3.2-20) contain heat exchanger components with an intended function of heat transfer; however, the applicant did not specify that reduction of heat transfer was an AERM for those components. The staff was not able to determine whether all credible aging effects for these components had been identified. By letter dated September 22, 2011, the staff issued RAI 3.3.2.4-1 requesting that the applicant provide the technical basis to demonstrate that reduction of heat transfer does not need to be managed for each of these items.

By letter dated November 21, 2011, the applicant stated that a reduction of heat transfer aging effect was not used for heat exchangers with environments of plant indoor air, ventilation atmosphere, or dry gas. For plant indoor air and ventilation atmosphere environments, the applicant stated that these environments are inside plant buildings, and because outdoor air is filtered prior to entry into the affected buildings, the buildings' clean air environments are not conducive to heat exchanger fouling and accumulation of dust on heat exchanger surfaces. For dry gas environments, the applicant stated that this environment is associated with chiller internal refrigerant gas, and that dry gas internal to a closed system is not conducive to heat exchanger fouling.

In its review of the applicant's response, the staff agreed that for an environment of dry gas associated with chiller internal refrigerant gas, an aging effect for reduction of heat transfer due to fouling is not applicable because there is no potential for dust or debris accumulation. However, for plant indoor air and ventilation atmosphere environments, the staff did not agree that filtering outdoor air prior to entry into the affected buildings would alleviate the need to manage reduction of heat transfer due to fouling in the associated heat exchangers. The staff questioned whether the air within the associated buildings is a "clean air environment," because dust and debris can be generated inside the buildings during normal plant activities. By letter dated February 28, 2012, the staff issued RAI 3.3.2.4-2 requesting that the applicant provide information to support its position that fouling is not an applicable aging mechanism for heat exchangers in plant indoor air environments, or provide an AMP to manage this aging effect.

In its response dated March 28, 2012, the applicant stated that the aging effect of fouling due to dust is not applicable for the following reasons: (a) 100 percent of the outside air supplied to the electrical auxiliary, mechanical auxiliary, and fuel handing buildings is filtered before passing into each building's HVAC system; (b) "filtered air is distributed throughout the buildings and then exhausted to the outside, thus maintaining a dust-free environment in each building"; (c) buildings are maintained clean by general housekeeping procedures, and if dust-generating activities occur, then the area is secured and any dust generation is contained; (d) a review of past cooler inspections located in the mechanical auxiliary and the fuel handing buildings determined that fouling of cooler fins does not occur; and (e) there is no plant operating experience related to loss of heat transfer due to heat exchanger fouling because of dust. The staff finds the applicant's response acceptable for these reasons: (a) the applicant maintains a dust-free environment in the associated buildings; (b) administrative controls are in place to prevent migration of dust generating activities to the cooler locations; (c) a review of past cooler inspections showed no fouling of cooler fins is occurring; (d) although the applicant did not cite the results of cooler inspections in the electrical auxiliary building, it is reasonable to expect similar results given the similarity in the environment and administrative controls; (e) there has been no plant-specific operating experience showing that fouling of heat exchanges in an air environment has occurred; and (f) it is not expected that the environment would change during the period of extended operation. The staff's concerns described in RAIs 3.3.2.4-1 and 3.3.2.4-2 are resolved.

Belzona Coating Exposed to Raw Water. As amended by letter dated June 3, 2014, LRA Table 3.3.2-4 states that Belzona coating exposed to raw water will be managed for loss of coating integrity by the Open-Cycle Cooling Water System Program. The AMR item cites generic note J.

The staff noted that although the applicant cited generic note J, LR-ISG-2013-01, "Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," provides AMR items to address this material, environment, and aging effect combination. GALL Report AMR item A-416 states that loss of coating integrity may be managed for metallic piping, piping, components, heat exchangers, and tanks with internal coatings/linings exposed to raw water, by AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks."

The staff's evaluation of the applicant's Open-Cycle Cooling Water System Program, as modified to address loss of coating integrity, is documented in SER Section 3.0.3.3.5. The staff finds the applicant's proposal to manage aging using the Open-Cycle Cooling Water System Program acceptable because: (a) the periodic visual inspections conducted by qualified personnel can detect indications of loss of coating integrity; (b) coatings that do not meet acceptance criteria are replaced; and (c) physical testing ensures that replaced coatings encompass sound coating/lining material.

Copper Alloy Closure Bolting Exposed to Raw Water (External). In LRA Table 3.3.2-4, as revised by letter dated October 22, 2014, the applicant stated that copper alloy closure bolting exposed to raw water (submerged) will be managed for loss of preload by the Bolting Integrity

Program. The AMR item cites generic note F, which states that the material is not in the GALL Report for this component.

The staff reviewed the associated item in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review, the staff noted that the GALL Report recommends that closure bolting be inspected for loss of preload and loss of material by the Bolting Integrity Program.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.5. The applicant addressed the GALL Report identified aging effect of loss of material for this component, material, and environment combination in another AMR item in LRA Table 3.3.2-4 and proposed to manage this aging effect with the Open-Cycle Cooling Water System Program. The staff notes that the closure bolts will be subject to visual inspections capable of detecting loss of material and leakage (i.e., loss of preload) at least once every 10 years. The staff further notes that these closure bolts are part of the ECW pump columns and these pumps are subject to quarterly performance tests in which flow and pressure parameters are monitored and trended. The staff notes that these quarterly inspections can identify degradation associated with loss of material and loss of preload of the closure bolts that result in leakage of the bolted connection. Therefore, the staff finds the applicant's proposal to manage aging using the Bolting Integrity and Open-Cycle Cooling Water System programs acceptable because the combination of preventive actions, tests, and inspection activities described above are able to detect and adequately manage the aging effects for the submerged closure bolts in the ECW pump before there is a loss of intended function.

Conclusion. 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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.5 Auxiliary Systems—Summary of Aging Management Evaluation—Reactor Makeup Water System—LRA Table 3.3.2-5

The staff's evaluation for stainless steel closure bolting exposed to plant indoor air, which will be managed for loss of preload by the Bolting Integrity Program and cites generic note H, is documented in SER Section 3.3.2.3.2.

As amended by its response to RAI SBPB-2-2, dated December 15, 2011, LRA Table 3.3.2.5 states that reactor makeup water storage tank floating elastomeric seals exposed to demineralized water will be managed for hardening and loss of strength by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The AMR item cites generic note G. The AMR item cites plant-specific note 2, which states that "[t]he Reactor Make-up Water Storage Tank floating seal cannot be readily inspected from the treated water side. Credit for aging management of the floating seal is by physical inspection from the accessible topside of the floating seal following the inspection attributes in XI.M38, Inspection of Internal Surfaces. The XI.M38 inspections will determine if the elastomeric floating seal is experiencing hardening, and loss of strength."

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the GALL Report, Revision 2, item AP-101, which states elastomers exposed to treated water should be 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 staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.18. The staff noted that, in its response, the applicant stated that the inspections for this seal look for thinning along the sides and at seams, seam adhesion, seam flotation, and condensation buildup on the top of the seals. The applicant also stated that the inspection manipulates the seals to inspect for elastomer hardening or other changes in mechanical properties. The staff also noted that the applicant revised LRA Section B2.1.22 to state that the first inspection of the seals will be conducted within 5 years prior to the period of extended operation with followup inspections every 5 years thereafter. The staff finds the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program from the accessible topside of the seal acceptable for the following reasons:

- The treated water environment is no worse in regard to elastomeric degradation than the plant indoor air environment on the topside of the seal because the treated water does not have any compounds that would cause accelerated aging of the seal, and the temperatures on both surfaces are similar.
- Visual inspections, augmented by physical manipulation of the material, will be conducted every 5 years.
- Visual inspections, augmented by physical manipulation of the material, are capable of detecting hardening and loss of strength in elastomeric materials.
- The inspections, conducted within 5 years prior to the period of extended operation with followup inspections every 5 years thereafter, are at a sufficient interval to detect aging.

Conclusion. 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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.6 Auxiliary Systems—Summary of Aging Management Evaluation—Component Cooling Water System—LRA Table 3.3.2-6

The staff's evaluation for stainless steel closure bolting exposed to plant indoor air, which will be managed for loss of preload by the Bolting Integrity Program and cites generic note H, is documented in SER Section 3.3.2.3.2.

The staff's evaluation for stainless steel heat exchangers exposed to treated borated water, which will be managed for reduction of heat transfer by the Water Chemistry and One-Time Inspection programs and cite generic note H, is documented in SER Section 3.2.2.3.3.

Heat Exchanger Titanium Exposed to Closed-Cycle Cooling Water. In LRA Tables 3.3.2-6 and 3.3.2-20, the applicant stated that for titanium heat exchangers exposed to CCCW, there is no aging effect, and no AMP is proposed. The AMR items cite generic note F.

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff finds in its review of heat exchanger-related AMR items, the applicant did not include reduction of heat transfer as an AERM for these components that have an intended function of heat transfer. By letter dated September 22, 2011, the staff issued RAI 3.3.2.4-1 requesting that, for those heat exchanger-related items in the LRA that list an intended function of heat transfer, the applicant provides the technical basis demonstrating that reduction of heat transfer does not need to be managed.

In its response dated November 21, 2011, the applicant stated that it had inadvertently omitted the aging effect of reduction of heat transfer. The applicant stated that it revised the tables to add the reduction of heat transfer aging effect for the affected heat exchanger components. The acceptance of the applicant's response is described in detail in SER Section 3.3.2.3.4. The staff finds that the applicant's proposal to manage only reduction of heat transfer acceptable based on its review of ASM Handbook, Volume 13B, "Corrosion: Materials," which states that titanium alloys are fully resistant to water, all natural waters, and steam up until temperatures in excess of 315 °C (600 °F) because of the formation of an adherent passive film made of titanium oxide. In addition, this reference indicates that typical contaminants encountered in natural water streams—such as iron and manganese oxides, sulfides, sulfates, carbonates, and chlorides—do not compromise the passivity of titanium. The staff finds the applicant's management of titanium alloys in CCCW acceptable because this environment is maintained to specific water quality specifications described in the EPRI Closed Cooling Water Chemistry Guideline Report and is unlikely to lead to situations that could compromise the passivity of the titanium alloys.

Copper Alloy Greater than 15 Percent Zinc Solenoid Valve Exposed to Plant Indoor Air. The staff's evaluation for copper alloy (greater than 15 percent Zn) solenoid valves internally exposed to plant indoor air, which will be managed for loss of material by the Selective Leaching of Materials Program and cite generic note G, is documented in SER Section 3.3.2.3.7.

Conclusion. 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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.7 Auxiliary Systems—Summary of Aging Management Evaluation—Compressed Air System—LRA Table 3.3.2-7

The staff's evaluation for stainless steel closure bolting exposed to plant indoor air, which will be managed for loss of preload by the Bolting Integrity Program and cites generic note H, is documented in SER Section 3.3.2.3.2.

Copper Alloy (Greater than 15 Percent Zinc) Solenoid Valve Exposed to Plant Indoor Air. In LRA Tables 3.3.2-6, 3.3.2-7, 3.3.2-19, and 3.4.2-2, as revised by letters dated November 30, 2011, and March 28, 2012, the applicant stated that copper alloy (greater than 15 percent Zn) solenoid valves internally exposed to plant indoor air will be managed for loss of material by the Selective Leaching of Materials Program. The AMR item cites generic note G and plant-specific note 3, which state that copper alloy greater than 15 percent Zn SCs with surfaces exposed to plant indoor air (internal) are subject to wetting due to condensation; thus, they are subject to loss of material due to selective leaching.

The staff reviewed the associated items in the LRA and considered whether the aging effect proposed by the applicant constitutes all of the credible aging effects for this component, material, and environment description. Copper alloys greater than 15 percent Zn are susceptible to SCC when exposed to ammonia or amines, provided sufficient tensile stresses are present (ASM International, *Metals Handbook Desk Edition*, second edition, 1998). The staff did not have sufficient information regarding the control of ammonia or amines in the vicinity of the instrument air intake; therefore, by letter dated September 22, 2011, the staff issued RAI 3.3.2.3.7-1 to request that the applicant describe what measures are in place to control or limit the presence of ammonia and amines. In its response dated October 25, 2011, the applicant stated that the instrument air intakes that contain the copper alloy valves are located inside the turbine generator building in an area designated as a housekeeping area. The area contains no standing water or nearby enclosures in which insects could build up. The applicant also stated that it does not use ammonia-based chemicals in the instrument air compressor intake area; however, some of the cleaning solutions may contain a very low concentration of ammonia, but they are used infrequently. The applicant concluded that the instrument air intake piping is not exposed to airborne amines or ammonia-based compounds in sufficient quantities to be of significance. The applicant also performed a review of STP operating experience but did not find any evidence of SCC associated with copper alloy greater than 15 percent Zn. Based on its review of the applicant's response, the staff agrees that ammonia or amines are not typically present or used in the vicinity of the air compressor intakes in sufficient concentration to induce SCC. Additionally, there are no instances of SCC of copper alloy greater than 15 percent Zn exposed to indoor air in the plant-specific operating experience. As such, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Selective Leaching of Materials Program is documented in SER Section 3.0.3.2.13. The staff finds the applicant's proposal to manage aging using the Selective Leaching of Materials Program acceptable because the program will use a one-time inspection, comprising both visual and mechanical techniques, of a sample of components for each system, material, and environment combination—including the copper alloy solenoid valves—to confirm that selective leaching does not occur.

<u>Coatings Exposed to Plant Indoor Air</u>. As amended by letter dated June 3, 2014, LRA Table 3.3.2-7 states that coatings exposed to plant indoor air will be managed for loss of coating integrity by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The AMR item cites generic note J.

The staff noted that although the applicant cited generic note J, LR-ISG-2013-01, "Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," provides AMR items to address this material, environment, and aging effect combination. GALL Report AMR item A-416 states that loss of coating integrity may be managed for metallic piping, piping, components, heat exchangers, and tanks with internal coatings/linings exposed to fluid environments, by AMP XI.M42.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, as modified to address loss of coating integrity, is documented in SER Section 3.0.3.3.5. 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: (a) the periodic visual inspections conducted by qualified personnel can detect indications of loss of coating integrity; (b) coatings that do not meet acceptance criteria are replaced; and (c) physical testing ensures that replaced coatings encompass sound coating/lining material.

Conclusion. 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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.8 Auxiliary Systems—Summary of Aging Management Evaluation—Primary Process Sampling System—LRA Table 3.3.2-8

Stainless Steel Expansion Joints, Heat Exchanger (Hydrogen Analyzer), Orifices, Piping, Pumps, Thermowells, Tubing, and Valves Exposed to Plant Indoor Air. In LRA Tables 3.3.2-8, 3.3.2-16, 3.3.2-20, and 3.3.2-23, the applicant stated that for stainless steel expansion joints, heat exchanger (hydrogen analyzer), orifices, piping, pumps, thermowells, tubing, or valves exposed to plant indoor air (internal), there is no aging effect, and no AMP is proposed. The AMR items cite generic note G, except for the expansion joint, which cites generic note H.

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff noted that the applicant's LRA submittal was based on Revision 1 of the GALL Report, which included the material and environment combination of stainless steel and plant indoor air (external) but did not include the combination of stainless steel and plant indoor air (internal). The staff also noted that the combination of stainless steel and plant indoor air (internal) has been added to Revision 2 of the GALL Report, and the GALL Report recommends that there are no AERM. However, the staff further noted that the applicant's environment of "plant indoor air" encompasses the GALL Report defined environment of "condensation" when used as an internal environment. Revision 2 of the GALL Report and SRP-LR state that stainless steel components are susceptible to loss of material when exposed to condensation, as documented in SRP-LR Table 3.3-1, item 95, and Table 3.4-1, item 39. It was unclear to the staff why these stainless steel components exposed to plant indoor air have no AERM since they may be exposed to condensation. By letter dated September 22, 2011, the staff issued RAI 3.0-1 requesting that the applicant identify which AMR items in the LRA are exposed to a plant indoor air environment for which humidity, condensation, moisture, or other contaminants are present. Additionally, if in identifying these items, the applicant determines that the AMR items have additional AERMs, the staff asked the applicant to propose AMP(s) to manage the aging effect or state the basis for why no AMP is required. The staff's concerns discussed in RAI 3.0-1 and followup RAI 3.0-1a are documented in SER Section 3.0.2.2.1.

By letter dated February 27, 2012, the applicant stated that internal surfaces of components exposed to "plant indoor air" are assumed to be exposed to condensation. The applicant revised the AMR items for internal surfaces of components exposed to "plant indoor air" to credit the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components program to manage loss of material. The AMR items were revised to cite generic note E and reference LRA Table 3.2.1, item 3.2.1.08, LRA Table 3.3.1, item 3.3.1.27, or LRA Table 3.3.1, item 3.3.1.54. The staff finds the applicant's response acceptable because the applicant revised the LRA to manage components exposed to condensation for loss of material, which is consistent with the GALL Report recommendations. The staff's evaluation of the AMR items associated with LRA Table 3.2.1, item 3.2.1.08, LRA Table 3.3.1, item 3.3.1.27, and LRA

Table 3.3.1, item 3.3.1.54, are documented in SER Sections 3.2.2.2.3.6, 3.3.2.2.10.5, and 3.3.2.1.6, respectively. The staff's concern described above is resolved.

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 functions will remain consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.9 Auxiliary Systems—Summary of Aging Management Evaluation—Chilled Water HVAC System—LRA Table 3.3.2-9

The staff's evaluation for carbon steel and stainless steel piping exposed to treated borated water, CCCW, and raw water, which will be managed for wall thinning by the Flow-Accelerated Corrosion Program and cite generic note H, is documented in SER Section 3.3.2.3.2.

Heat Exchanger Titanium Exposed to Raw Water Internal. In LRA Tables 3.3.2-6, 3.3.2-9, and 3.3.2-20, the applicant stated that titanium heat exchangers exposed to raw water will be managed for reduction of heat transfer by the Open-Cycle Cooling Water System Program. The AMR items cite generic note F.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noted that the applicant did not address loss of material due to crevice corrosion and that various types of titanium alloys exposed to raw water with certain chloride levels can undergo loss of material due to crevice corrosion. By letter dated September 22, 2011, the staff issued RAI 3.3.2.6-1 requesting that the applicant provide additional information on what type of titanium alloys are used in the heat exchangers exposed to raw water and explain why aging management of loss of material due to crevice corrosion is not included.

In its response dated November 21, 2011, the applicant stated that the titanium heat exchanger tubes exposed to raw water meet the specification for ASME SB-338, Grade 2 (unalloyed titanium). The applicant further stated that corrosion of this titanium requires elevated temperatures that are greater than approximately 71 °C (160 °F). The applicant also stated that the maximum outlet temperature during normal operation in the ECW system is approximately 43 °C (110 °F) and that the heat exchanger tubes are not subject to crevice corrosion. The staff reviewed the ASM Handbook, Volume 13, "Corrosion," for crevice corrosion in titanium and titanium alloys and determined that at the operating temperature of approximately 43 °C (110 °F), Grade 2 titanium is not susceptible to loss of material due to crevice corrosion. The staff finds the applicant's response acceptable because the titanium material used in the heat exchangers is not susceptible to loss of material due to crevice corrosion under the exposure conditions. The staff's concern described in RAI 3.3.2.6-1 is resolved.

The staff's evaluation of the applicant's Open-Cycle Cooling Water System Program is documented in SER Section 3.0.3.2.6. The staff finds the applicant's proposal to manage aging using the Open-Cycle Cooling Water System Program acceptable because it includes surveillance and control techniques to manage aging effects caused by biofouling, corrosion, erosion, protective coating failures, and silting, and it includes periodic inspections to monitor aging effects.

Heat Exchanger Titanium Exposed to Dry Gas. In LRA Table 3.3.2-9, the applicant stated that for titanium heat exchangers exposed to dry gas, there is no aging effect, and no AMP is proposed. The AMR items cite generic note F.

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff finds the applicant's proposal acceptable based on its review of the ASM Handbook, Volume 13B, "Corrosion: Materials," which states that the oxide film on titanium alloys provides an effective barrier to attack from most gases in wet or dry conditions, including oxygen, nitrogen, dry hydrochloric acid, sulfur dioxide, ammonia, hydrogen cyanide, carbon dioxide, carbon monoxide, and hydrogen sulfide. The reference also states that this protection extends to temperatures in excess of 150 °C (300 °F). The staff finds the applicant's management of titanium alloys in dry gas acceptable because this environment is unlikely to lead to a situation that could compromise the passivity of the titanium alloy.

Conclusion. 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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.10 Auxiliary Systems—Summary of Aging Management Evaluation—Electrical Auxiliary Building and Control Room HVAC System—LRA Table 3.3.2-10

The staff's evaluation for stainless steel closure bolting exposed to plant indoor air, which will be managed for loss of preload by the Bolting Integrity Program and cites generic note H, is documented in SER Section 3.3.2.3.2.

Copper Alloy Tubing Exposed to Ventilation Atmosphere (Internal). In LRA Table 3.3.2-10, the applicant stated that for copper alloy tubing exposed to a ventilation atmosphere (internal), 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 to confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff noted that LRA Table 3.0-1, "Mechanical Environments," states that the applicant's ventilation atmosphere environment encompasses several environments used in the GALL Report, including air-indoor uncontrolled, and condensation (internal). The staff also noted that the GALL Report recommends that copper-alloy piping, piping components, and piping elements exposed to condensation (internal) be managed for loss of material but states that there is no aging effect for copper alloy components exposed to air-indoor uncontrolled. By letter dated September 22, 2011, the staff issued RAI 3.3.2.3.10-1 requesting that the applicant clarify whether the environment for the copper alloy tubing includes condensation or other sources of moisture and provide justification that the copper alloy tubing has no AERMs during the period of extended operation.

In its response dated November 21, 2011, the applicant stated that the normal environment for the copper alloy tubing exposed to ventilation atmosphere (internal) in LRA Table 3.3.2-10 is considered to be condensation (internal). The applicant revised the AMR item in LRA Table 3.3.2-10 for copper alloy tubing exposed to ventilation atmosphere (internal) to indicate that loss of material will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The applicant associated this revised AMR item with

LRA Table 3.3.1, item 3.3.1.28, which is for copper alloy fire protection piping, piping components, and piping elements exposed to condensation and cited generic note E.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.18, and the staff's evaluation of AMR results associated with LRA Table 3.3.1, item 3.3.1.28, is documented in SER Section 3.3.2.2.10, item 6. The staff finds the applicant's response and its proposal to manage loss of material for copper alloy components exposed to condensation using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because it is consistent with the recommendations in the GALL Report, as documented in SER Section 3.3.2.2.10, item 6. The staff's concern described in RAI 3.3.2.3.10-1 is resolved.

Conclusion. 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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.11 Auxiliary Systems—Summary of Aging Management Evaluation—Fuel Handling Building HVAC System—LRA Table 3.3.2-11

The staff reviewed LRA Table 3.3.2-11, which summarizes the results of AMR evaluations for the fuel handling building HVAC system component groups.

The staff's review did not find any items indicating plant-specific notes F through 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 associated with notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.12 Auxiliary Systems—Summary of Aging Management Evaluation—Mechanical Auxiliary Building HVAC System—LRA Table 3.3.2-12

PVC Piping Exposed to Plant Indoor Air Internal and External Environments. In LRA Tables 3.3.2-12, 3.3.2-24, and 3.3.2-27, the applicant stated that for PVC piping exposed to plant indoor air internal and external environments, there is no aging effect, and no AMP is proposed. The AMR items cite generic note F. Items associated with LRA Tables 3.3.2-12 and 3.3.2-27 cite plant-specific notes 1 and 6, respectively, which state, "PVC is relatively unaffected by water, concentrated alkalis, and non-oxidizing acids, oils, and ozone."

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff finds the applicant's proposal acceptable based on its review of the GALL Report, Revision 2, items VII.J.AP-268 and VII.J.AP-269, which identify no aging effects and propose no AMP for PVC piping, piping components, and piping elements exposed to air-indoor uncontrolled and condensation internal environments.

Conclusion. 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 appropriately evaluated the material and environment combinations and that no aging management is necessary to provide reasonable assurance that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.13 Auxiliary Systems—Summary of Aging Management Evaluation—Miscellaneous HVAC Systems (In Scope)—LRA Table 3.3.2-13

The staff reviewed LRA Table 3.3.2-13, which summarizes the results of AMR evaluations for the miscellaneous HVAC systems (in scope) component groups.

The staff's review did not find any items indicating plant-specific notes F through 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 associated with notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.14 Auxiliary Systems—Summary of Aging Management Evaluation—Containment Building HVAC System—LRA Table 3.3.2-14

The staff's evaluation for stainless steel closure bolting exposed to plant indoor air, which will be managed for loss of preload by the Bolting Integrity Program and cites generic note H, is documented in SER Section 3.3.2.3.2.

Conclusion. 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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.15 Auxiliary Systems—Summary of Aging Management Evaluation—Standby Diesel Generator Building HVAC System—LRA Table 3.3.2-15

The staff reviewed LRA Table 3.3.2-15, which summarizes the results of AMR evaluations for the SDG building HVAC system component groups.

The staff's review did not find any items indicating plant-specific notes F through 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 associated with notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.16 Auxiliary Systems—Summary of Aging Management Evaluation—Containment Hydrogen Monitoring and Combustible Gas Control System—LRA Table 3.3.2-16

The staff's evaluation for stainless steel closure bolting exposed to plant indoor air which will be managed for loss of preload by the Bolting Integrity Program and cites generic note H, is documented in SER Section 3.3.2.3.2.

Conclusion. 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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.17 Auxiliary Systems—Summary of Aging Management Evaluation—Fire Protection System—LRA Table 3.3.2-17

Closure Bolting Carbon Steel Exposed to Atmosphere and Weather. In LRA Tables 3.3.2-17, 3.3.2-21, 3.3.2-27, and 3.3.2-28, the applicant stated that the carbon steel closure bolting exposed to atmosphere and weather will be managed for loss of preload by the Bolting Integrity Program. The AMR items cite generic note H. Items associated with closure bolting cite plant-specific note 1, which states that loss of preload is conservatively applied for all closure bolting.

The staff noted that this material and environment combination is not identified in the GALL Report, Revision 1; however, several items (e.g., EP-118, AP-263, SP-151) in GALL Report, Revision 2, address steel closure bolting exposed to air-outdoor, which is consistent with the applicant's atmosphere and weather environment, and recommend GALL Report AMP XI.M18, "Bolting Integrity," to manage loss of preload. The applicant addressed the GALL Report identified aging effects for this component, material, and environment combination in AMR items in LRA Tables 3.3.2-17, 3.3.2-21, 3.3.2-27, and 3.3.2-28.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.5. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because it includes bolting assembly and maintenance controls, such as application of appropriate gasket alignment, torque, lubricants, and preload. Additionally, it inspects bolted connections to ensure detection of leakage occurs before the leakage becomes excessive.

Elastomeric Caulking and Sealant Exposed to Atmosphere and Weather, and Carbon Steel Tank Exposed to Concrete. As amended by letter dated November 4, 2011, LRA Table 3.3.2-17 states that elastomeric caulking and sealant exposed to atmosphere and weather will be managed for hardening and loss of strength by the External Surfaces Monitoring Program, and carbon steel tank exposed to concrete will be 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. Items associated with elastomeric caulking and sealant also cite plant-specific note 4, which states that "[t]he External Surfaces Monitoring Program (B2.1.20) is used to manage the hardening and loss of strength of the caulking found between the firewater storage tank (FWST) bottom to concrete foundation interface to prevent water entry under the tank bottom." Items associated with the carbon steel tank also cite plant-specific note 3, which states that "[a] visual inspection of the external surface of the bottom of tanks sitting directly on soil or concrete cannot be performed. A volumetric examination from the inside of the bottom of the tank is performed in lieu of an external inspection."

During the audit, the staff noted that LRA Table 3.3.2-17 credits the External Surfaces Monitoring Program to manage loss of material for the steel fire water storage tank, which is exposed to atmosphere and weather and is constructed on a concrete foundation. The External Surfaces Monitoring Program does not require sealant or caulking as a preventive action, and it does not call for bottom thickness measurements of the tank. During the AMP audit, the staff and applicant walked down the fire water storage tank and noted that caulking was applied at its interface with the concrete foundation. Although structural caulking and sealants exposed to atmosphere and weather are managed by the Structures Monitoring Program in LRA Table 3.5.2-3, the periodicity of inspections for the Structures Monitoring Program is not as frequent as those recommended by GALL Report AMP XI.M29. By letter dated August 15, 2011, the staff issued RAI B2.1.20-5 requesting that the applicant state the basis for not inspecting caulking and sealants used at the tank to concrete interface joint on a 2-year interval and for not conducting tank bottom thickness measurements for the fire water storage tank.

In its responses dated September 15, 2011, and November 4, 2011, the applicant stated the following:

- LRA Table 3.3.2-17 was revised to include caulking and sealant for the firewater storage tank.
- The External Surfaces Monitoring Program will be used to manage hardening and loss of strength of the material, with inspections that are conducted at least once every RFO.
- The program was revised to include visual inspections of protective paints, coatings, caulking, or sealants (the staff noted that the program already included manipulation of elastomeric materials).
- The external surface of the tank exposed to concrete was added to LRA Table 3.3.2-17 and will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program for loss of material.
- The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program was revised to include volumetric examination of the tank bottoms from the inside of the tank.
- The volumetric examinations will be conducted within 5 years prior to entering the period of extended operation, or whenever the tank is drained.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. For the elastomeric caulking and sealant exposed to atmosphere and weather, based on its review of GALL Report, Revision 2, AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” which states that hardening and loss of strength are the only applicable aging effects given that the seal is a passive moisture barrier at the base of the tank and is not subject to mechanical wear, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination. For the carbon steel tank exposed to concrete, based on its review of the GALL Report, Revision 2, item SP-115, which states that loss of material is the only applicable aging effect, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff’s evaluations of the applicant’s External Surfaces Monitoring Program and Internal Surfaces in Miscellaneous Piping and Ducting Components Program are documented in SER Sections 3.0.3.1.16 and 3.0.3.2.18, respectively. The staff finds the applicant’s proposal and response to RAI B2.1.20-5 to manage aging using the External Surfaces Monitoring Program Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because, although the aging for an aboveground tank and its caulked interface would normally be managed by GALL Report AMP XI.M29, “Aboveground Metallic Tanks,” the proposed changes and existing provisions of the applicant’s programs—including conducting visual and physical manipulation inspections of the caulking every refueling outage and volumetric examinations of the tank’s bottom within 5 years prior to entering the period of extended operation and whenever the tank is drained—are consistent with GALL Report AMP XI.M29.

Copper Valves and Solenoid Valves Exposed to Atmosphere and Weather. In LRA Table 3.3.2-17, the applicant stated that copper alloy valves and solenoid valves exposed to atmosphere and weather (external) will be 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 considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the GALL Report, which states in item VII.I.AP-159 that copper alloy components exposed to outdoor air are susceptible to loss of material, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff’s evaluation of the applicant’s External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.16. The staff noted that the material and environment combination for the component are within the scope of the External Surfaces Monitoring Program. The staff finds the applicant’s proposal to manage aging using the External Surfaces Monitoring Program acceptable because the visual inspections and surveillance activities included in the AMP are adequate to detect loss of material on the external surface of copper alloy valves and solenoid valves prior to loss of intended function.

Cast Iron Valves Exposed to Plant Indoor Air. In LRA Table 3.3.2-17, the applicant stated that cast iron (gray cast iron) valves exposed to plant indoor air (external) will be managed for loss of material by the External Surfaces Monitoring Program. The AMR items cite generic notes F and G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noted that, based on Section IX.C of the GALL Report, gray cast iron is categorized with the group “steel” for certain environments such as plant indoor air. Based on further review of the GALL Report, which states that carbon steel valves exposed to plant indoor air are only susceptible to loss of material, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff’s evaluation of the applicant’s External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.16. The staff noted that the material and environment combination for the component is within the scope of the External Surfaces Monitoring Program. The staff finds the applicant’s proposal to manage aging using the External Surfaces Monitoring Program acceptable because the visual inspections and surveillance activities included in the AMP are adequate to detect loss of material on the external surface of gray cast iron valves prior to loss of intended function.

Stainless Steel Tubing, Closure Bolting, Piping, and Valves Exposed to Atmosphere and Weather (External). In LRA Tables 3.3.2-17 and 3.3.2-27, the applicant stated that for stainless steel tubing, closure bolting, piping, and valves exposed to atmosphere and weather (external), there is no aging effect, and no AMP is proposed. The AMR items cite generic note G, except for the closure bolting in Table 3.3.2-27, which cites generic note H, and a plant-specific note, which states that loss of preload is considered to be applicable for all closure bolting.

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material, and environment combination. With regard to the plant-specific note, which applies for closure bolting in miscellaneous systems in scope only for Criterion 10 CFR 54.4(a)(2), the staff noted that the applicant credits the Bolting Integrity Program to manage loss of preload for these bolts and that use of the Bolting Integrity Program to manage loss of preload is consistent with recommendations in the GALL Report. The staff also noted that the applicant's LRA submittal was based on Revision 1 of the GALL Report, which does not include the material and environment combination of stainless steel and outdoor air. However, the combination of stainless steel exposed to outdoor air was added to Revision 2 of the GALL Report, which was issued after the applicant's LRA submittal. Revision 2 of the GALL Report states that cracking due to SCC and loss of material due to pitting and crevice corrosion could occur in stainless steel components exposed to outdoor air. Revision 2 of the SRP-LR, Sections 3.3.2.2.3 and 3.3.2.2.5, state that cracking due to SCC and loss of material due to pitting and crevice corrosion could occur for stainless steel piping, piping components, piping elements, and tanks exposed to outdoor air and that these aging effects can occur in environments containing sufficient halides (primarily chlorides) and in which condensation or deliquescence is possible. Revision 2 of the GALL Report recommends further evaluation to determine whether an AMP is needed to manage these aging effects based on the environmental conditions applicable to the plant. By letter dated September 22, 2011, the staff issued RAI 3.3.2.3.17-1 requesting that the applicant provide an evaluation of whether an AMP is needed to manage cracking due to SCC and loss of material due to pitting and crevice corrosion in stainless steel components exposed to outdoor air (atmosphere and weather), as recommended in Revision 2 of the GALL Report.

In its response dated November 21, 2011, the applicant stated that the prevailing outdoor air is not an aggressive halide-rich environment because the plant is not within 5 miles of a saltwater coastline, there are no roads treated with salt in the winter within ½ mile of the plant, the soil does not contain more than trace chlorides, there are no chlorine-treated water sources nearby, there is no runoff from cattle farms, and there is no industry pollution at the site. The applicant also stated that local rains tend to wash outside surfaces of components rather than concentrate contaminants and that its review of plant operating experience found no occurrences of aging of stainless steel components exposed to outdoor air. The staff finds the applicant's response and its proposal that stainless steel components exposed to outdoor air have no AERMs acceptable because outdoor environmental conditions at the applicant's plant are not conducive to aging of stainless components, as described in Revision 2 of the GALL Report and the SRP-LR. The staff's concern described in RAI 3.3.2.3.17-1 is resolved.

Belzona Coating Exposed to Raw Water. As amended by letter dated June 3, 2014, LRA Table 3.3.2-17 states that Belzona coating exposed to raw water will be managed for loss of coating integrity by the Fire Water System Program. The AMR item cites generic note J.

The staff noted that although the applicant cited generic note J, LR-ISG-2013-01, "Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," provides AMR items to address this material, environment, and aging effect combination. GALL Report AMR item A-416 states that loss of coating integrity may be managed for metallic piping, piping, components, heat exchangers, and tanks with internal coatings/linings exposed to raw water by AMP XI.M42.

The staff's evaluation of the applicant's Fire Water System Program, as modified to address loss of coating integrity, is documented in SER Section 3.0.3.3.5. The staff finds the applicant's proposal to manage aging using the Fire Water System Program acceptable because: (a) the periodic visual inspections conducted by qualified personnel can detect indications of loss of coating integrity; (b) coatings that do not meet acceptance criteria are replaced; and (c) physical testing ensures that replaced coatings encompass sound coating/lining material.

Stainless Steel, Copper Alloy, Carbon Steel, and Galvanized Carbon Steel Piping and Piping Components Exposed to Plant Indoor Air or Raw Water. As amended by letter dated June 3, 2014, LRA Table 3.3.2-17 states that stainless steel, copper alloy, carbon steel, and galvanized carbon steel piping and piping components exposed to plant indoor air or raw water will be managed for loss of material or flow blockage due to fouling by the Fire Water System Program. The AMR items cite generic note H.

The staff noted that although the applicant cited generic note H, LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," provides AMR items to address these material, environment, and aging effect combinations. GALL Report AMR items A-33, A-55, AP-197, and A-404, as modified by LR-ISG-2012-02, state that loss of material or flow blockage due to fouling may be managed for stainless steel, copper alloy, carbon steel, and galvanized carbon steel piping and piping components exposed to plant indoor air or raw water by AMP XI.M27, "Fire Water System."

The staff's evaluation of the applicant's Fire Water System Program is documented in SER Section 3.0.3.2.10. The staff finds the applicant's proposal to manage aging using the Fire Water System Program acceptable because the periodic visual inspections, monitoring of the fire protection system piping pressure, and tests can detect loss of material or flow blockage due to fouling.

Carbon Steel Fire Water Storage Tanks Exposed to Atmosphere/Weather, Concrete, Plant Indoor Air and Raw Water. As amended by letter dated June 3, 2014, LRA Table 3.3.2-17 states that carbon steel fire water storage tanks exposed to atmosphere/weather, concrete, plant indoor air, and raw water will be managed for loss of material by the Fire Water System Program. The AMR item cites generic notes G and H.

The staff noted that although the applicant cited generic notes G and H, with the exception of the concrete environment, LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," provides an AMR item to address these material, environment, and aging effect combinations. GALL Report AMR item A-412, as modified by LR-ISG-2012-02, states that loss of material may be managed for carbon steel fire water storage tanks exposed to outdoor air, plant indoor air, and raw water by AMP XI.M27, "Fire Water System."

The staff's evaluation of the applicant's Fire Water System Program is documented in SER Section 3.0.3.2.10. The staff finds the applicant's proposal to manage aging using the Fire Water System Program acceptable because the periodic visual inspections and followup tests if degraded conditions are detected can detect loss of material. In addition, the periodic bottom thickness ultrasonic tests can detect loss of material on the bottom side of the fire water storage tank exposed to concrete.

Carbon Steel, Ductile Iron, and Cast Iron Hydrants and Various Piping Components Exposed to Raw Water. In LRA Table 3.3.2-17, as modified by letter dated June 3, 2014, the applicant stated that carbon steel, ductile iron, and cast iron hydrants, piping, pumps, tanks, and valves exposed to raw water will be managed for loss of material due to recurring internal corrosion by the Fire Water System Program. The AMR items cite generic note H, with plant-specific note 6, which refers to a new AMR item, VII.G.A-400, which is discussed in LR-ISG-2012-02, for recurring internal corrosion.

The staff noted that this material and environment combination is identified in the GALL Report, which addresses carbon steel, ductile iron, and cast iron components exposed to raw water and recommends the Fire Water System Program; however, the applicant identified this additional aging mechanism based on its review of past operating experience as delineated in LR-ISG-2012-02. The applicant addressed the GALL Report identified aging effects for these component, material, and environment combinations in other AMR items in LRA Table 3.3.2-17.

During its review of these items, the staff noted that the applicant did not identify the specific cause of the recurring loss of material in these components and could not determine if the Fire Water System Program included appropriate activities for managing this mechanism. By letter dated April 13, 2015, the staff issued RAI 3.0.3-1a, requesting that the applicant identify the aging mechanism that led to the recurring internal corrosion and to provide further justification on the basis for using the Fire Water System Program. The staff also asked the applicant to clarify whether the recurring internal corrosion occurs in the "normally dry, periodically wetted, and not easily drained" portions of the system, or in other portions of the system.

In its response dated June 11, 2015, the applicant stated that the aging mechanism causing the recurring loss of material was general, pitting, and crevice corrosion that occurred in the portions of the system that are normally dry, periodically wetted, and not easily drained. The applicant also stated that the Fire Water System was revised in its letter of June 3, 2014, to perform augmented inspections and testing on those portions of the system consistent with guidance in LR-ISG-2012-02, Section C.

The staff's evaluation of the applicant's Fire Water System Program is documented in SER Section 3.0.3.2.10. The staff finds the applicant's response to RAI 3.0.3-1a acceptable and the proposal to manage recurring internal corrosion using the above AMP acceptable because the program was specifically enhanced to address the loss of material associated with the portions of the system that are normally dry, but periodically wetted and not easily drained.

Conclusion. 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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.18 Auxiliary Systems—Summary of Aging Management Evaluation—Standby Diesel Generator Fuel Oil Storage and Transfer System—LRA Table 3.3.2-18

Aluminum Flame Arrestors Exposed to Atmosphere and Weather. In LRA Table 3.3.2-18, the applicant stated that aluminum flame arrestors exposed to atmosphere and weather (external) will be managed for loss of material by the External Surfaces Monitoring Program. The AMR item cites generic note J.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the GALL Report, which states in item V.E.EP-114 that aluminum components exposed to outdoor air are susceptible to loss of material, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.16. The staff noted that the material and environment combination for the component are within the scope of the External Surfaces Monitoring Program. The staff finds the applicant's proposal to manage aging using the External Surfaces Monitoring Program acceptable because the visual inspections and surveillance activities included in the AMP are adequate to detect loss of material on aluminum flame arrestors prior to loss of intended function.

<u>Elastomer Flexible Hoses Exposed to Fuel Oil Internal Environment</u>. In LRA Table 3.3.2-18, the applicant stated that for elastomer flexible hoses exposed to fuel oil internal environment, 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 could not confirm that no credible aging effects are applicable for this component, material, and environment combination because the applicant did not identify the specific material of the flexible connections. The staff noted that certain elastomers, such as natural rubbers and ethylene-propylene-diene (EPDM), are not resistant to fuel oil. By letter dated September 22, 2011, the staff issued RAI 3.3.2.3.18-1 requesting that the applicant state the materials of construction for the flexible hoses exposed to fuel oil and, if the flexible hoses are constructed of a material that is not resistant to fuel oil, to propose an AMP or explain why no AMP is necessary.

In its response dated November 21, 2011, the applicant stated that, after further evaluation, the applicant determined that the flexible hoses are constructed of nitrile, which is not resistant to the fuel oil environment over the long term. The applicant also stated that in lieu of managing the aging of these hoses, they will be replaced on a periodic basis based on vendor recommendations. The applicant revised LRA Tables 3.3.2-18 and 2.3.3-18 to remove this item, and LRA Section 3.3.2.1.18 was revised to remove elastomeric materials and the hardening and loss of strength aging effect.

The staff finds the applicant's response and proposal acceptable. Given that the flexible hoses will be replaced on a periodic basis based on vendor recommendations, the items are no longer long-lived; therefore, they can be screened out of being age-managed, and the applicant appropriately revised all applicable portions of the LRA to reflect the change.

<u>Conclusion</u>. 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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.19 Auxiliary Systems—Summary of Aging Management Evaluation—Chemical and Volume Control System—LRA Table 3.3.2-19

The staff's evaluation for stainless steel heat exchangers exposed to treated borated water, which will be managed for reduction of heat transfer by the Water Chemistry and One-Time Inspection programs and cite generic note H, is documented in SER Section 3.2.2.3.3.

Nickel Alloy Heat Exchangers Exposed to Air. In LRA Table 3.3.2-19, the applicant stated that for nickel alloy heat exchangers exposed to air with borated water leakage, there is no aging effect, and no AMP is proposed. The AMR item cites generic note G. Plant-specific note 1 states that "NUREG-1801 does not address the aging effect of nickel alloys in borated water leakage. Nickel-alloys subject to an air with borated water leakage environment are similar to stainless steel in a borated water leakage environment and do not experience aging effects due to borated water leakage."

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment. In conducting this review, the staff considered all aging effects that are contained in the GALL Report for nickel alloys irrespective of the environment and all aging effects associated with the environment "air with borated water leakage," irrespective of the material. For nickel alloys in any environment, the GALL Report lists the following aging effects: cracking due to SCC, fatigue, denting, and loss of material. For the environment "air with borated water leakage," the GALL Report lists only loss of material. For these nickel alloy components exposed to borated water leakage, the aging effect cracking due to SCC need not be considered because neither the GALL Report nor operating experience have revealed any instances of cracking of nickel alloy components exposed to air with borated water leakage. This absence of cracking is likely a function of the environmental oxygen content, the component temperature, and the boric acid concentration. The issue of fatigue of these components will be addressed as a TLAA elsewhere in this SER, as appropriate. Due to the location of these components, denting is not a credible aging effect. Loss of material is also not a credible aging effect for these components exposed to this environment based on Revision 2 to the GALL Report. This revision specifically contains an item, which indicates that no aging effect is applicable and no AMP is recommended when nickel alloy components are exposed to air with borated water leakage. This change to the GALL Report is based on data contained in EPRI 1000975, "Boric Acid Corrosion Guidebook," Revision 1. This report contains data (page 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."

On the basis of its review, the staff concludes that, for nickel alloy components exposed to air with borated water leakage and listed in LRA Table 3.3.2-19, the applicant appropriately evaluated the material and environment combinations and that no aging management is necessary to provide reasonable assurance that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Calcium Silicate and Fiberglass Insulation Exposed to Plant Indoor Air (External). As amended by letter dated June 3, 2014, in LRA Table 3.3.2-19, the applicant stated that calcium silicate and fiberglass insulation exposed to plant indoor air (external) will be managed for reduced thermal insulation resistance due to moisture intrusion by the External Surfaces Monitoring Program.

The staff noted that although the applicant did not cite a generic note, LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," provides AMR items to address this material, environment, and aging effect combination. GALL Report AMR item S-403 states that reduced thermal insulation resistance due to moisture intrusion is managed for calcium silicate and fiberglass insulation exposed to plant indoor air (external) by GALL Report AMP XI.M36.

By letter dated October 22, 2014, the applicant amended LRA Table 3.3.2-19 to state that fiberglass insulation exposed to plant indoor air (external) has no AERM and no AMP. In addition, the applicant cited a plant-specific note 5, but there is no description of the note. The staff noted that no basis was provided for the changes.

By letter dated April 12, 2016, the staff issued RAI 3.0.3-1c requesting that the applicant (a) state the basis for not citing reduced thermal insulation resistance due to moisture intrusion for jacketed fiberglass insulation, and (b) provide a description of the plant-specific note 5 cited in LRA Table 3.3.2-19.

In its response dated May 19, 2016, the applicant stated that LRA Table 3.3.2-19 was updated to include the aging effect of reduced thermal insulation resistance due to moisture intrusion for fiberglass. In addition, plant-specific note 5 was updated to cite GALL Report item VIII.I.S-403 as the basis of the AERM. The staff finds the applicant's response acceptable because the changes to LRA Table 3.3.2-19 are consistent with GALL Report item VIII.S-403.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.16. The staff finds the applicant's proposal to manage aging using the External Surfaces Monitoring Program acceptable because periodic visual inspections of the insulation jacketing will be conducted to verify that the insulation is water-tight.

<u>Thermoplastic Tank Exposed to Plant Indoor Air</u>. In LRA Table 3.3.2-19, the applicant stated that for a thermoplastic tank exposed to plant indoor air, there is no aging effect, and no AMP is proposed. The AMR items cite generic note F.

The staff reviewed the associated item in the LRA and could not confirm that no credible aging effects are applicable for this component, material, and environment combination because there are many material types of thermoplastics with variable aging effects when exposed to environments such as ultraviolet light, high radiation, high temperature, ozone, or chemicals. By letter dated September 22, 2011, the staff issued RAI 3.3.2.3.19-1 requesting that the applicant state the specific material of construction for the thermoplastic tank and explain whether there are external environmental factors in the vicinity of the component such as ultraviolet light, high radiation, ozone, or chemical species. If these factors could contribute to aging, the staff asked the applicant to state the aging effect and the basis for not managing the aging. Alternatively, if external environmental factors could contribute to aging, the staff asked the applicant to propose an AMP to manage the aging effect.

In its response dated November 21, 2011, the applicant stated that the tanks are constructed of polyethylene and located in an area of the plant that is not exposed to ultraviolet light, radiation, ozone, extreme temperatures, or chemicals. The staff finds the applicant's response and proposal acceptable because, based on a review of Plastic Materials, 7th edition (J. Brydson, Elsevier), in the absence of environmental stressors (e.g., ultraviolet light, high radiation, high temperature, ozone, chemical species), aging (i.e., oxidation) of polyethylene at room temperature is not a concern. The staff's concern described in RAI 3.3.2.3.19-1 is resolved.

<u>Thermoplastic Tank Exposed to Zinc Acetate</u>. In LRA Table 3.3.2-19, the applicant stated that the thermoplastic tank exposed to Zn acetate will be managed for cracking by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The AMR item cites generic note J.

The staff reviewed the associated item in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noted that this material and environment combination is not identified in the GALL Report. The staff did not have sufficient technical information to determine if a cracking aging effect is the only aging effect to consider for this component, material, and environment combination. By letter dated September 22, 2011, the staff issued RAI 3.3.2.3.19-1 requesting that the applicant identify, for each component subject to the cracking aging effect, the system's design temperature, the minimum and maximum operating temperature, the normal operating temperature at which the component is exposed to the Zn acetate environment, and the concentration (in ppm) of that environment.

In its response dated November 21, 2011, the applicant stated a brief description outlining the operation of the CVCS, the location of the system, the operating temperatures, and the Zn solution injection temperature. The applicant also stated the Zn acetate powder maximum impurity concentrations and the design temperatures of the system's metering pump casing and the medium-density polyethylene (MDPE) Zn mixing tank. The applicant also stated that the maximum continuous design temperature rating of the tank is 60 °C (140 °F), with intermittent design service of approximately 71 °C (160 °F); however, the normal operating temperature is approximately 24-27 °C (75-80 °F). Based on its review of "Chemical Resistance of Plastics and Elastomers," Table "Polyolefins," William Woishnis, 2008, 4th edition, which states that MDPE is resistant to degradation by a saturated solution of lead acetate up to 60 °C (140 °F)—and the fact that Zn acetate and lead acetate, derivatives of acetic acid, are both weak acids—the staff finds that there are no additional aging effects that should be accounted for with this component, material, and environment combination; therefore, the applicant's response is acceptable. The staff's concern described in RAI 3.3.2.3.19-1 is resolved.

The staff's evaluation of the applicant's Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.18. The staff finds the applicant's proposal to manage aging using the Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because the program's visual inspections are capable of detecting cracking of the Zn mixing tank exposed to Zn acetate, and the program will use supplemental inspections at areas where the likelihood of significant degradation has been assessed.

Heat Exchanger (Concentrated Boric Acid Sample Cooler) Nickel-Alloy Exposed to Treated Borated Water (Internal). In LRA Table 3.3.2-19, the applicant stated that the nickel-alloy concentrated boric acid sample cooler exposed to treated borated water (internal) will be 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 considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of EPRI's "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools," Revision 4, Figure 1, "Treated Water/Stainless Steel and Nickel-Base Alloys," which states that nickel-based alloys in treated water are susceptible to a loss of material aging effect, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff does not have sufficient technical information to determine if the component's loss of material effect is being adequately managed absent a One-Time Inspection Program to confirm effectiveness of the Water Chemistry Program. By letter dated December 6, 2011, the staff issued RAI 3.3.2.3.19-2 requesting that the applicant present a technical justification for omitting an inspection program for this component.

In its response dated January 5, 2012, the applicant stated that the One-Time Inspection Program for aging management of the concentrated boric acid sample cooler was inadvertently omitted, and the applicant revised LRA Table 3.3.2-19 to reflect that change. The staff finds the applicant's response acceptable because the management of the component with the Water Chemistry and the One-Time Inspection Program is now consistent with the guidance in the GALL Report and includes a confirmation program with the primary AMP. The staff's concern described in RAI 3.3.2.3.19-2 is resolved.

The staff's evaluation of the applicant's Water Chemistry and One-Time Inspection programs is documented in SER Sections 3.0.3.2.1 and 3.0.3.1.4, respectively. The staff noted that the Water Chemistry Program manages loss of material by monitoring and controlling chemical environments in the RCS and related auxiliary system based on industry guidelines. The staff finds the applicant's proposal to manage aging using the Water Chemistry Program acceptable because the applicant uses an appropriate, adequate approach to loss of material for this component, material, and environment combination, and the One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Program by conducting one-time inspections.

<u>Pump, Valve Stainless Steel Exposed to Zinc Acetate</u>. In LRA Table 3.3.2-19, the applicant stated that the stainless steel pump and valve exposed to Zn acetate will be managed for loss of material by the Water Chemistry Program and the One-Time Inspection Program. The AMR items cite generic note G. The staff noted that this material and environment combination is not identified in the GALL Report.

The staff does not have sufficient technical information to determine if a loss of material effect is occurring and if it is the only aging effect to consider for this component, material, and environment combination. By letter dated September 9, 2011, the staff issued RAI 3.3.2.3.19-1 requesting that the applicant identify, for each component subject to a loss of material aging effect, the system's design temperature, the minimum and maximum operating temperature, the normal operating temperature at which the component is exposed to the Zn acetate environment, and the concentration (in ppm) of that environment.

In its response dated November 21, 2011, the applicant stated a brief description outlining the operation of the CVCS, the location of the system, the operating temperatures, and the Zn solution injection temperature. The applicant also stated the Zn acetate powder maximum impurity concentrations and the design temperatures of the system's metering pump casing and the Zn mixing tank.

The staff finds the applicant's response acceptable based on the stated impurity concentrations in the Zn acetate powder, which are reduced to 1 percent of their original values when in solution; the system operating temperature; and the Pressurized Water Reactor Primary Water Chemistry Guidelines, Volume 1, Revision 6, EPRI Product No. 1014986, Final Report, December 2007, which states that there are no deleterious effects of Zn acetate. The staff's concern described in RAI 3.3.2.3.19-1 is resolved.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection programs are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.4, respectively. The staff noted that the Water Chemistry Program manages loss of material by monitoring and controlling the chemical environment in the plant's systems within industry guidelines to mitigate aging effects. The staff finds the applicant's proposal to manage aging using the Water Chemistry and One-Time Inspection programs acceptable because the programs will limit the concentration of chemicals known to cause corrosion and add chemicals to inhibit degradation to minimize a loss of material aging effect while confirming the effectiveness of the Water Chemistry Program by conducting one-time inspections.

Copper Alloy (Greater than 15 Percent Zinc) Solenoid Valve Exposed to Plant Indoor Air. The staff's evaluation for copper alloy (greater than 15 percent Zn) solenoid valves internally exposed to plant indoor air, which will be managed for loss of material by the Selective Leaching of Materials program and cite generic note G, is documented in SER Section 3.3.2.3.7.

Stainless Steel Components Exposed to Plant Indoor Air (External). In LRA Tables 3.3.2-19 and 3.3.2-27, as modified by letter dated June 3, 2014, the applicant stated that stainless steel piping, tanks, and valves externally exposed to indoor air will be managed for loss of material by the External Surfaces Monitoring Program. The AMR items cite generic note H and plant-specific note 6, which discusses a new GALL Report item, VII.A2.A-405, that was established in LR-ISG-2012-02 for loss of material on insulated stainless steel components exposed to condensation. The staff notes that the GALL Report item cited by the applicant recommends the External Surfaces Monitoring of Mechanical Components AMP to manage this aging effect.

The staff's evaluations of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.16. The staff notes that the applicant modified the AMP, by letter dated June 3, 2014, to specifically address the issues discussed in LR-ISG-2012-02. The staff finds the applicant's proposal to manage loss of material in insulated stainless steel components, using the External Surfaces Monitoring Program, acceptable because periodic inspections for damage to the insulation jacketing that could allow moisture in-leakage will result in insulation removal for inspection of the component exterior surface.

Calcium Silicate and Fiberglass Insulation Exposed to Plant Indoor Air (External). As amended by letter dated June 3, 2014, in LRA Table 3.3.2-19, the applicant stated that calcium silicate and fiberglass insulation exposed to plant indoor air (external) will be managed for reduced thermal insulation resistance due to moisture intrusion by the External Surfaces Monitoring Program.

The staff noted that although the applicant did not cite a generic note, LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," provides AMR items to address this material, environment, and aging effect combination. GALL Report AMR item S-403 states that reduced thermal insulation resistance due to moisture intrusion is managed for calcium silicate and fiberglass insulation exposed to plant indoor air (external) by GALL Report AMP XI.M36.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.16. The staff finds the applicant's proposal to manage aging using the External Surfaces Monitoring Program acceptable because periodic visual inspections of the insulation jacketing will be conducted to verify that the insulation is water-tight.

Conclusion. 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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.20 Auxiliary Systems—Summary of Aging Management Evaluation—Standby Diesel Generator and Auxiliaries System—LRA Table 3.3.2-20

The staff's evaluation for stainless steel closure bolting exposed to plant indoor air, which will be managed for loss of preload by the Bolting Integrity Program and cites generic note H, is documented in SER Section 3.3.2.3.2.

<u>Heat Exchanger Titanium Exposed to Closed-Cycle Cooling Water</u>. The staff's evaluation for titanium heat exchangers exposed to CCCW, which will be managed for reduction of heat transfer by the Closed-Cycle Cooling Water Program and cite generic note F, is documented in SER Section 3.3.2.3.6.

<u>Heat Exchanger Titanium Exposed to Plant Indoor Air</u>. In LRA Table 3.3.2-20, the applicant stated that for titanium heat exchangers exposed to plant indoor air, there is no aging effect, and no AMP is proposed. The AMR items cite generic note F.

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff finds the applicant's proposal acceptable based on its review of ASM Handbook, Volume 13B, "Corrosion: Materials," which states that the oxide film on titanium alloys provides an effective barrier against attack from most gases in wet or dry conditions, including oxygen, nitrogen, dry hydrochloric acid, sulfur dioxide, ammonia, hydrogen cyanide, carbon dioxide, carbon monoxide, and hydrogen sulfide. The reference also states that this protection extends to temperatures in excess of 150 °C (300 °F). The staff finds the applicant's management of titanium alloys in plant indoor air acceptable because this environment is unlikely to lead to a situation that could compromise the passivity of the titanium alloy.

<u>Copper Alloy Valves Exposed to Plant Indoor Air (Internal)</u>. In LRA Table 3.3.2-20, the applicant stated that for copper alloy valves exposed to plant indoor air (internal), 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 to confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff noted that LRA Table 3.0-1, "Mechanical Environments," states that the applicant's plant indoor air (internal) environment encompasses several environments used in the GALL Report, including condensation (internal), air, and moist air. The staff also noted that the GALL Report recommends that copper-alloy piping, piping components, and piping elements exposed to condensation (internal) be managed for loss of material but states that there is no aging effect for copper alloy components exposed to air-indoor uncontrolled. By letter dated September 22, 2011, the staff issued RAI 3.3.2.3.10-1 requesting that the applicant clarify whether the environment for the copper alloy valves includes condensation or other sources of moisture and provide justification that the copper alloy valves have no AERMs during the period of extended operation.

In its response dated November 21, 2011, the applicant stated that the normal environment for the copper alloy valves exposed to plant indoor air (internal) in LRA Table 3.3.2-20 is considered to be condensation (internal). The applicant revised the AMR item in LRA Table 3.3.2-20 for the copper alloy valves exposed to plant indoor air (internal) to indicate that loss of material will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The applicant associated this revised AMR item with LRA

Table 3.3.1, item 3.3.1.28, which is for copper alloy fire protection piping, piping components, and piping elements exposed to condensation, and cited generic note E.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.18, and the staff's evaluation of AMR results associated with LRA Table 3.3.1, item 3.3.1.28, is documented in SER Section 3.3.2.2.10, item 6. The staff finds the applicant's response and its proposal to manage loss of material due to pitting and crevice corrosion for copper alloy components exposed to condensation using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because it is consistent with the GALL Report recommendations, as documented in SER Section 3.3.2.2.10, item 6. The staff's concern described in RAI 3.3.2.3.10-1 is resolved.

Heat Exchanger Titanium Exposed to Lubricating Oil. In LRA Table 3.3.2-20, the applicant stated that titanium heat exchangers exposed to lubricating oil will be managed for reduction of heat transfer by the Lubricating Oil Analysis and One-Time Inspection AMPs. The AMR item cites generic note F.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noted that the GALL Report does not address the combination of titanium heat exchangers exposed to lubricating oil for reduction of heat transfer. However, the staff noted that the GALL Report does address titanium heat exchanger components exposed to indoor air but does not describe any aging effects. Based on its review of the GALL Report and the ASM Handbook, which states that titanium is highly resistant to corrosion; the staff determined that water and contamination in lubricating oil may lead to reduction of heat transfer, and that the applicant identified all credible aging effects for this component, material, and environment combination.

Filter Aluminum Exposed to Lubricating Oil. In LRA Table 3.3.2-20, the applicant stated that aluminum filters exposed to lubricating oil will be managed for loss of material by the Lubricating Oil Analysis and One-Time Inspection AMPs. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noted that the GALL Report does not address the combination of aluminum filters exposed to lubricating oil for loss of material. However, the staff noted that the GALL Report does address aluminum piping components exposed to lubricating oil for loss of material. Based on its review of the GALL Report and the ASM Handbook, both of which state that loss of material in the form of pitting and crevice corrosion may occur in this environment, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

Conclusion. 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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.21 Auxiliary Systems—Summary of Aging Management Evaluation—Nonsafety-Related Diesel Generators and Auxiliary Fuel Oil System—LRA Table 3.3.2-21

The staff's evaluation for carbon steel closure bolting exposed to atmosphere and weather, which will be managed for loss of preload by the Bolting Integrity Program and cites generic note H, is documented in SER Section 3.3.2.3.17.

Copper-Alloy Piping, Tubing, and Valves Exposed to Atmosphere and Weather. In LRA Table 3.3.2-21, the applicant stated that copper-alloy piping, tubing, and valves exposed to atmosphere and weather (external) will be 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 considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the GALL Report, which states in item VII.I.AP-159 that copper alloy components exposed to outdoor air are susceptible to loss of material, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.16. The staff noted that the material and environment combination for the component is within the scope of the External Surfaces Monitoring Program. The staff finds the applicant's proposal to manage aging using the External Surfaces Monitoring Program acceptable because the visual inspections and surveillance activities included in the AMP are adequate to detect loss of material on the external surface of copper-alloy piping, tubing, and valves prior to loss of intended function.

Conclusion. 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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.22 Auxiliary Systems—Summary of Aging Management Evaluation—Liquid Waste Processing System—LRA Table 3.3.2-22

The staff's evaluation for stainless steel closure bolting exposed to plant indoor air, which will be managed for loss of preload by the Bolting Integrity Program and cites generic note H, is documented in SER Section 3.3.2.3.2.

Piping Stainless Steel Exposed to Sodium Hydroxide. In LRA Table 3.3.2-22, the applicant stated that the stainless steel piping exposed to sodium hydroxide will be managed for loss of material by the Water Chemistry Program and One-Time Inspection Program. The AMR items cite generic note G. Items associated with stainless steel piping and Table 3.3.2-22 cite plant-specific note 2, which states that "operating experience does not suggest there is any aging effect, and the use of stainless steel up to approximately 93 °C (200 °F) and 50 weight-percent sodium hydroxide is common in industrial applications with no special consideration for aging. There is no NUREG-1801 line that covers NaOH." The staff noted that this material and environment combination is not identified in the GALL Report.

The staff needed additional technical information to determine if a loss of material effect is occurring and if it is the only aging effect to consider for this component, material, and environment combination. By letter dated September 22, 2011, the staff issued RAI 3.3.2.3.22-1 requesting that the applicant identify, for each component subject to a loss of material aging effect, the system's design temperature, the minimum and maximum operating temperature, the normal operating temperature at which the component is exposed to the sodium hydroxide environment, and the concentration (in ppm) of that environment.

In its response dated November 21, 2011, the applicant stated that a review of plant operation found that the chemical addition skid has never been used for sodium hydroxide addition and that there are no plans to use the skid, that there are no procedures for sodium hydroxide addition, and that there are no stocks of this chemical at the plant. The applicant also stated that the skid is abandoned-in-place but is retained in-scope for spatial interaction, and the components will be changed from an environmental exposure of sodium hydroxide to raw water. The applicant letter also amended LRA Tables 3.3.2-22 and 3.3.2-27 whose raw water components will be age managed by LRA AMP B2.1.22, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components." The staff finds the applicant's response acceptable because the components have never been exposed or never will be exposed to sodium hydroxide. The staff's evaluation of these items exposure to raw water is documented in SER Section 3.3.2.1.4, "Loss of Material Due to Pitting and Crevice Corrosion, and Fouling." The staff's concern described in RAI 3.3.2.3.22-1 is resolved.

Conclusion. 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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.23 Auxiliary Systems—Summary of Aging Management Evaluation—Radioactive Vents and Drains System—LRA Table 3.3.2-23

The staff's evaluation for stainless steel closure bolting exposed to plant indoor air, which will be managed for loss of preload by the Bolting Integrity Program and cites generic note H, is documented in SER Section 3.3.2.3.2.

Conclusion. 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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.24 Auxiliary Systems—Summary of Aging Management Evaluation—Nonradioactive Waste Plumbing Drains and Sumps System—LRA Table 3.3.2-24

The staff's evaluation for stainless steel closure bolting exposed to plant indoor air, which will be managed for loss of preload by the Bolting Integrity Program and cites generic note H, is documented in SER Section 3.3.2.3.2.

The staff's evaluation of PVC piping exposed to plant indoor air with no aging effects and no AMP required, citing generic note F, is documented in SER Section 3.3.2.3.12.

PVC Piping Exposed to Raw Water Internal Environment. In LRA Table 3.3.2-24, the applicant stated that for PVC piping exposed to a raw water internal environment, there is no aging effect, and no AMP is proposed. The AMR item cites generic note F.

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material, and environment combination. LRA Table 3.0-1, "Mechanical Environments," states in part, that "[f]loor drains and building sumps may be exposed to a variety of untreated water that is classified as raw water for the determination of aging effects. Raw water may contain contaminants, including oil and boric acid, as well as originally treated water that is not monitored by a chemistry program." Based on current industry research and operating experience related to PVC piping and piping components, the staff has determined that the factors related to passive aging that may contribute to the degradation of thermoplastics include chemical degradation through hydrolysis and oxidation reactions with a solvent. The staff noted that the raw water environment in the floor drains could include contaminants such as oil and boric acid, which could have a deleterious effect on thermoplastics from chemical or oxidation reactions. By letter dated September 22, 2011, the staff issued RAI 3.3.2.3.24-1 requesting that the applicant do the following:

- state the specific type of PVC piping exposed to raw water in LRA Table 3.3.2-24
- state whether this piping could be exposed to contaminants such as oil and boric acid or identify other environmental factors that could result in aging effects
- explain the basis for why there are no AERMs based on the environmental factors for which the piping is exposed or provide an AMP to adequately manage the aging effect

In its response dated November 21, 2011, the applicant stated that the PVC piping in LRA Table 3.3.2-24 that is exposed to raw water is the drain line for the control room air handling units, the internal environment of the control room air handling units is free of chemicals that could contaminate the control room, the drain lines are at atmospheric pressure and temperature, and the lines are not exposed to sunlight. The staff finds the applicant's response and proposal acceptable because even though the applicant did not state the specific type of PVC piping, given the piping's service conditions (moisture condensed from the control room's air), all PVC material types would not be subject to aging, and the GALL Report, item AP-269, states that there is no AERM or recommended AMP. The staff's concern described in RAI 3.3.2.3.24-1 is resolved.

Conclusion. 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 appropriately evaluated the material and environment combinations and that no aging management is necessary to provide reasonable assurance that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.25 Auxiliary Systems—Summary of Aging Management Evaluation—Oily Waste System—LRA Table 3.3.2-25

The staff's evaluation for stainless steel closure bolting exposed to plant indoor air, which will be managed for loss of preload by the Bolting Integrity Program and cites generic note H, is documented in SER Section 3.3.2.3.2.

Conclusion. 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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.26 Auxiliary Systems—Summary of Aging Management Evaluation—Radiation Monitoring (Area and Process) Mechanical System—LRA Table 3.3.2-26

The staff reviewed LRA Table 3.3.2-26, which summarizes the results of AMR evaluations for the radiation monitoring (area and process) mechanical system component groups.

The staff's review did not find any items indicating plant-specific notes F through 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 associated with notes A through E is documented in SER Section 3.3.2.1.

3.3.2.3.27 Auxiliary Systems—Summary of Aging Management Evaluation—Miscellaneous Systems In Scope ONLY for Criterion 10 CFR 54.4(a)(2)—LRA Table 3.3.2-27

The staff's evaluation for stainless steel closure bolting exposed to plant indoor air, which will be managed for loss of preload by the Bolting Integrity Program and cites generic note H, is documented in SER Section 3.3.2.3.2.

The staff's evaluation for carbon steel and stainless steel piping exposed to treated borated water, CCCW, and raw water, which will be managed for wall thinning by the Flow-Accelerated Corrosion Program and cite generic note H, is documented in SER Section 3.3.2.3.2.

The staff's evaluation of PVC piping exposed to plant indoor air with no aging effects and no AMP required, citing generic note F, is documented in SER Section 3.3.2.3.12.

The staff's evaluation for carbon steel closure bolting exposed to atmosphere and weather, which will be managed for loss of preload by the Bolting Integrity Program and cites generic note H, is documented in SER Section 3.3.2.3.17.

The staff's evaluation for stainless steel components exposed to plant outdoor air (atmosphere and weather) for which the LRA states there is no AERM and no AMP is needed, citing generic note G or H, is documented in SER Section 3.3.2.3.17.

The staff's evaluation for stainless steel piping and valves externally exposed to plant indoor air, which will be managed for loss of material by the External Surfaces Monitoring Program and cites generic note H, is documented in SER Section 3.3.2.3.19.

Aluminum Piping and Valves Exposed to Atmosphere and Weather. In LRA Table 3.3.2-27, the applicant stated that aluminum piping and valves exposed to atmosphere and weather (external) will be 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 considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the GALL Report, which states in item V.E.EP-114 that aluminum components exposed to outdoor air are susceptible to loss of material, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.16. The staff noted that the material and environment combination for the component are within the scope of the External Surfaces Monitoring Program. The staff finds the applicant's proposal to manage aging using the External Surfaces Monitoring Program acceptable because the visual inspections and surveillance activities included in the AMP are adequate to detect loss of material on aluminum piping and valves prior to loss of intended function.

<u>Copper-Alloy Piping, Pump, and Valve Exposed to Potable Water (Internal)</u>. In LRA Table 3.3.2-27, the applicant stated that copper-alloy piping, pump, and valve exposed to potable water (internal) will be 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.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the GALL Report, Revision 2, which states in item VII.E5.AP-271 that copper-alloy piping, piping components, and piping elements exposed to raw water (potable) will be managed for loss of material due to pitting and crevice corrosion, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.18. The staff noted that the applicant's Internal Surfaces in Miscellaneous Piping and Ducting Components Program manages loss of material and will use the work control process for preventive maintenance and surveillance to conduct and document inspections using visual inspections. The staff also noted that the applicant's program will use supplemental inspections at intervals and locations where the likelihood of significant degradation has been assessed to manage aging effects for components served by the program. The staff finds the applicant's proposal to manage aging using the Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because the program's visual inspections are capable of detecting loss of material exposed to potable water (internal), and the program will use supplemental inspections at areas where the likelihood of significant degradation has been assessed.

<u>Nickel-Alloy Piping Exposed to Plant Indoor Air (Internal)</u>. In LRA Table 3.3.2-27, the applicant stated that nickel-alloy piping exposed to plant indoor air (internal) will be 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.

In LRA Table 3.0-1, "Mechanical Environments," the description of plant indoor air (when used as internal environment) states that "[p]lant indoor air (internal) or non-dried compressed gas is evaluated with the GALL Report environment of condensation when the air contains significant amounts of moisture (enough to cause loss of material) and the internal surface has temperatures below the dew point."

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the GALL Report, which states in item VII.E5.AP-274 that nickel-alloy piping, piping components, and piping elements exposed to condensation (internal) will be managed for loss of material due to pitting, crevice corrosion, and MIC, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.18. The staff noted that the applicant's Internal Surfaces in Miscellaneous Piping and Ducting Components Program manages loss of material and will use the work control process for preventive maintenance and surveillance to conduct and document inspections using visual inspections. The staff also noted that the applicant's program will use supplemental inspections at intervals and locations where the likelihood of significant degradation has been assessed to manage aging effects for components served by the program. The staff finds the applicant's proposal to manage aging using the Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because the visual inspections, in conjunction with the supplemental inspections at locations of likely significant degradation, are capable of detecting loss of material exposed to plant indoor air (internal).

Nickel-Alloy Piping, Valve Exposed to Sodium Hydroxide. In LRA Table 3.3.2-27, the applicant stated that nickel-alloy piping and valve exposed to sodium hydroxide will be 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.

The staff noted that insufficient technical information was present to determine whether a loss of material aging effect is occurring and whether it is the only aging effect to consider for this component, material, and environment combination. By letter dated September 22, 2011, the staff issued RAI 3.3.2.3.22-1 requesting that the applicant identify, for each component subject to a loss of material aging effect, the system's design temperature, the minimum and maximum operating temperature, the normal operating temperature at which the component is exposed to the sodium hydroxide environment, and the concentration (in ppm) of that environment.

In its response dated November 21, 2011, the applicant stated that a review of operation found that the chemical addition skid has never been used for sodium hydroxide addition, that there are no plans to use the skid, that there are no procedures for sodium hydroxide addition, and that there are no stocks of this chemical at the plant. The applicant also stated that the skid is abandoned-in-place but is retained in-scope for spatial interaction and that the components will be changed from an environmental exposure of sodium hydroxide to raw water. The applicant also amended LRA Tables 3.3.2-22 and 3.3.2-27 to reflect that nickel-alloy piping exposed to raw water will be age managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The staff finds the applicant's response acceptable because the components have never been exposed and never will be exposed to sodium hydroxide. The staff's evaluation of these AMR items' exposure to raw water is documented in SER Section 3.3.2.1.3, "Loss of Material Due to General, Pitting, and Crevice Corrosion." The staff's concern described in RAI 3.3.2.3.22-1 is resolved.

Glass Sight Gauge Exposed to Sodium Hydroxide. In LRA Table 3.3.2-27, the applicant stated that a glass sight gauge exposed to sodium hydroxide will be 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.

The staff noted that insufficient technical information was present to determine if a loss of material effect is occurring and if it is the only aging effect to consider for this component, material, and environment combination. By letter dated September 22, 2011, the staff issued RAI 3.3.2.3.22-1 requesting that the applicant identify, for each component subject to a loss of material aging effect, the system's design temperature, the minimum and maximum operating temperature, the normal operating temperature at which the component is exposed to the sodium hydroxide environment, and the concentration (in ppm) of that environment.

In its response dated November 21, 2011, the applicant stated that a review of operation found that the chemical addition skid has never been used for sodium hydroxide addition, that there are no plans to use the skid, that there are no procedures for sodium hydroxide addition, and that there are no stocks of this chemical at the plant. The applicant also stated that the skid is abandoned-in-place but is retained in-scope for spatial interaction and that the components will be changed from an environmental exposure of sodium hydroxide to raw water. The applicant also amended LRA Tables 3.3.2-22 and 3.3.2-27 to reflect that the glass gauge exposed to raw water will be age managed by LRA AMP B2.1.22, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components." The staff finds the applicant's response acceptable because the components have never been exposed or never will be exposed to sodium hydroxide. The staff's evaluation of these items is that, consistent with the GALL Report, this material, component, and environment has no AERM. The staff's concern described in RAI 3.3.2.3.22-1 is resolved.

The staff's evaluation of the applicant's Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.18. The staff noted that the applicant's Internal Surfaces in Miscellaneous Piping and Ducting Components Program manages loss of material and will use the work control process for preventive maintenance and surveillance to conduct and document inspections using visual inspections. The staff also noted that the applicant's program will use supplemental inspections at intervals and locations where the likelihood of significant degradation has been assessed to manage aging effects for components served by the program. The staff finds the applicant's proposal to manage aging using the Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because the visual inspections, in conjunction with the supplemental inspections at locations of likely significant degradation, are capable of detecting loss of material exposed to raw water.

Carbon Steel Tank, Piping Exposed to Potable Water (Internal). In LRA Table 3.3.2-27, the applicant stated that carbon steel tanks and piping exposed to potable water (internal) will be 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.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the GALL Report, which states that steel tanks and piping are subject to a loss of material, in various environments (example GALL Report items VIII.E.SP-115 and VIII.E.S-31), the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination. The staff noted that the GALL Report recommends that the periodic GALL Report AMP XI.M29, “Aboveground Metallic Tanks,” program be used for the management of a tank’s exterior loss of material. The staff noted that GALL Report AMP XI.M29 recommends periodic visual inspections of the steel surfaces, which is consistent with the periodic opportunistic visual inspections of the “Internal Surfaces in Miscellaneous Piping and Ducting Components Program.” The staff also noted that the GALL Report for carbon steel piping exposed to condensation (internal) recommends the “Internal Surfaces in Miscellaneous Piping and Ducting Components Program” to manage loss of material (example GALL Report, item V.D2.E-27).

The staff’s evaluation of the applicant’s Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.18. The staff noted that the applicant’s Internal Surfaces in Miscellaneous Piping and Ducting Components Program manages loss of material for internal surfaces of piping and other components that are not inspected by other AMPs. The staff also noted that the applicant’s program will use periodic maintenance, predictive maintenance, surveillance testing, and corrective maintenance for the components within the program. The staff finds the applicant’s proposal to manage aging using the Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because the program addresses a component (the tank interior) that is not addressed by other programs by using a periodic maintenance program that is supplemented by predictive maintenance, surveillance testing, and a corrective maintenance program, which also uses visual inspections to detect aging effects that could result in a loss of component intended function. The staff finds the applicant’s proposal to manage aging of carbon steel piping using the Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because the program uses visual inspections that are supplemented by predictive maintenance, surveillance testing, and a corrective maintenance program, which are acceptable methods to manage this aging effect.

Carbon Steel Valve, Cast Iron Exposed to Potable Water (Internal). In LRA Table 3.3.2-27, the applicant stated that carbon steel valve exposed to potable water (internal) will be 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.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the GALL Report, which states in item VIII.G.SP-136 that steel piping, piping components, and piping elements exposed to raw water (potable) will be managed for loss of material due to due to general, pitting, crevice, and galvanic corrosion, MIC, and fouling that leads to corrosion, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff’s evaluation of the applicant’s Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.18. The staff noted that the applicant’s Internal Surfaces in Miscellaneous Piping and Ducting Components Program manages loss of material and will use the work control process for preventive maintenance and surveillance to conduct and document inspections using visual inspections. The staff also noted that the applicant’s program will use supplemental inspections at intervals and locations where the likelihood of significant degradation has been assessed to manage aging effects for components served by the program. The staff finds the applicant’s proposal to manage aging using the Internal Surfaces in Miscellaneous Piping and Ducting Components Program acceptable because the program’s visual inspections are capable of detecting loss of material exposed to potable water (internal), and the program will use supplemental inspections at areas where the likelihood of significant degradation has been assessed.

PVC Piping Exposed to Potable Water (Internal). In LRA Table 3.3.2-27, the applicant stated that for PVC piping exposed to potable water (internal), there is no aging effect, and no AMP is proposed. The AMR item cites generic note F.

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff noted that the evaluated components are in the potable water system and that this system is not a high temperature-high pressure system. LRA Table 3.0-1, "Mechanical Environments," defines potable water as water treated for drinking or other personnel uses. The staff finds the applicant's proposal acceptable for the following reasons: (a) GALL Report item SP-153 states that for PVC piping exposed to condensate, there is no AERM or recommended AMP; (b) as defined by the applicant, potable water is treated water suitable for drinking, is benign by nature, and is free of contaminants; and (c) because potable water is at least as benign as condensate, no aging effects from PVC piping exposure to potable water are anticipated.

Piping, Accumulator, Pump, Sight Gauge, Strainer, Tank, and Valve Stainless Steel Exposed to Sodium Hydroxide. In LRA Table 3.3.2-27, the applicant stated that the stainless steel accumulator, piping, pump, sight gauge, strainer, tank, and valve exposed to sodium hydroxide will be managed for loss of material by the Water Chemistry Program. The AMR items cite generic note G. Items associated with stainless steel piping and Table 3.3.2-27 cite plant-specific note 2, which states "that operating experience does not suggest there is any aging effect, and the use of stainless steel up to approximately 93 ° (200 °F) and 50 weight-percent sodium hydroxide is common in industrial applications with no special consideration for aging. There is no NUREG-1801 line that covers sodium hydroxide environment." The staff noted that this material and environment combination is not identified in the GALL Report, to address stainless steel accumulator, piping, pump, sight gauge, strainer, tank, and valve exposed to sodium hydroxide for loss of material.

The staff did not have sufficient technical information to determine if a loss of material effect is occurring and if it is the only aging effect to consider for this component, material, and environment combination. By letter dated September 22, 2011, the staff issued RAI 3.3.2.3.22-1 requesting that the applicant identify, for each component subject to a loss of material aging effect, the system's design temperature, the minimum and maximum operating temperature, the normal operating temperature at which the component is exposed to the sodium hydroxide environment, and the concentration (in ppm) of that environment.

In its response dated November 21, 2011, the applicant stated that a review of operation found that the chemical addition skid has never been used for sodium hydroxide addition, that there are no plans to use the skid, that there are no procedures for sodium hydroxide addition, and that there are no stocks of this chemical at the plant. The applicant also stated that the skid is abandoned-in-place but is retained in-scope for spatial interaction and that the components will be changed from an environmental exposure of sodium hydroxide to raw water. The applicant's letter also amended LRA Tables 3.3.2-22 and 3.3.2-27, whose raw water components will be age managed by LRA AMP B2.1.22, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components." The staff finds the applicant's response acceptable because the components have never been exposed or never will be exposed to sodium hydroxide. The staff's evaluation of these items exposure to raw water is documented in SER Section 3.3.2.1.4, "Loss of Material Due to Pitting and Crevice Corrosion, and Fouling." The staff's concern described in RAI 3.3.2.3.22-1 is resolved.

Gray Cast Iron Solenoid Valve Exposed to Potable Water. By letter dated November 4, 2011, the applicant amended LRA Table 3.3.2-27 to add an AMR item for gray cast iron solenoid valve internally exposed to potable water, which will be managed for loss of material by the Selective Leaching of Materials Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and considered whether the aging effect proposed by the applicant constitutes all of the credible aging effects for this component, material, and environment description. In accordance with the GALL Report, Revision 2, gray cast iron (which is included in the material definition of "steel") is vulnerable to general, pitting, and crevice corrosion. The staff noted that the applicant addressed loss of material for this component, material, and environment combination in an AMR item in LRA Table 3.3.2-27 and will manage the effects of aging with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program.

The staff's evaluation of the applicant's Selective Leaching of Materials Program is documented in SER Section 3.0.3.2.13. The staff finds the applicant's proposal to manage aging using the Selective Leaching of Materials Program acceptable because the program will use a one-time inspection, comprised of both visual and mechanical techniques, of a sample of components for each system-material-environment combination, including gray cast iron valves, to confirm that selective leaching does not occur.

Conclusion. 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 appropriately evaluated the material and environment combinations and that no aging management is necessary to provide reasonable assurance that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.28 Auxiliary Systems—Summary of Aging Management Evaluation—Lighting Diesel Generator—LRA Table 3.3.2-28

The staff's evaluation for carbon steel closure bolting exposed to atmosphere and weather, which will be managed for loss of preload by the Bolting Integrity Program and cites generic note H, is documented in SER Section 3.3.2.3.17.

Elastomer Flexible Hoses Exposed to Lubricating Oil Internal Environment. In LRA Table 3.3.2-28, the applicant stated that for elastomer flexible hoses exposed to a lubricating oil internal environment, 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 could not confirm that no credible aging effects are applicable for this component, material, and environment combination because the applicant did not identify the specific material of the flexible hoses. The staff noted that certain elastomers such as natural rubbers and EPDM are not resistant to lubricating oil. By letter dated January 30, 2012, the staff issued RAI 3.3.2.3.28-1 requesting that the applicant state the materials of construction for the flexible hoses exposed to lubricating oil. The staff also asked that, if the flexible hoses are constructed of a material that is not resistant to lubricating oil, the applicant propose an AMP or state the basis for why no AMP is necessary.

In its response dated February 16, 2012, the applicant stated that, based upon a plant walkdown, the material of construction of the flexible hoses could not be determined; therefore, it would manage the aging of these items with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The applicant revised LRA 3.3.2-28 to reflect that hardening and loss of strength of the components would be managed by this program.

The staff finds the applicant's response and proposal acceptable because elastomers exposed to lube oil would only be subject to hardening and loss of strength as an aging mechanism. The periodic opportunistic inspections of the Internal Surfaces in Miscellaneous Piping and Ducting Components Program include visual and physical manipulation examinations of the material that are capable of detecting hardening and loss of strength. In addition, although the applicant does not know the material type of these hoses, had they been constructed of a material that was not resistant to accelerated damage by exposure to lubricating oil, inservice failures of the hoses would have occurred. During the staff's review of the corrective action database conducted as part of the AMP audit, no such failures were noted.

Conclusion. 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 functions will remain consistent with the CLB during 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 functions will remain 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:

- main steam system
- auxiliary steam system and boilers
- feedwater system
- demineralized water (make-up) system
- SG blowdown system
- auxiliary feedwater system

3.4.1 Summary of Technical Information in the Application

LRA Section 3.4 provides AMR results for the steam and power conversion system components and component groups. In LRA Table 3.4.1, "Summary of Aging Management Evaluations in Chapter VIII of NUREG-1801 for Steam and Power Conversion System," the applicant provided a summary comparison of its AMRs to those evaluated in the GALL Report for steam and power conversion system components and component groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's operating experience review included industry sources, a review of the GALL Report, and operating experience issues identified since the issuance of the GALL Report.

3.4.2 Staff Evaluation

The staff reviewed LRA Section 3.4 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for steam and power conversion system components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will remain 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 to examine the applicant's AMPs and related documentation to confirm the applicant's claims that certain AMPs were consistent with the corresponding GALL Report AMPs. The staff did not repeat its review of the matters described in the GALL Report. The staff's evaluations of the AMPs are documented in SER Section 3.0.3.

The staff reviewed the AMRs to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did confirm that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. Details of the staff's evaluation are discussed in SER Sections 3.4.2.1 and 3.4.2.2.

The staff also reviewed the AMRs not consistent with or not addressed in the GALL Report. The review evaluated whether all plausible aging effects were identified and whether the aging effects listed were appropriate for the combination of materials and environments specified. Details of the staff's evaluation are discussed in SER Section 3.4.2.3.

For components 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 confirm the applicant's claims.

Table 3.4-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.4 and addressed in the GALL Report.

Table 3.4-1 Staff Evaluation for Steam and Power Conversion System Components in the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to steam or treated water (3.4.1.1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Fatigue is a TLAA (see SER Sections 3.4.2.2.1 and 4.3)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel 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 Program and One-TIme Inspection Program	Consistent with the GALL Report (see SER Section 3.4.2.2.2, item 1)
Steel heat exchanger components exposed to treated water (3.4.1.3)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable to STP	Consistent with the GALL Report (see SER Section 3.4.2.2.2, item 1)
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 Program and One-TIme Inspection Program	Consistent with the GALL Report (see SER Section 3.4.2.2.2, item 1)
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	BWR only	Not applicable to PWRs (see SER Section 3.4.2.1.1)
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 Program and One-TIme Inspection Program	Consistent with the GALL Report (see SER Sections 3.4.2.2.2, item 1, and 3.4.2.2.7, item 1)
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 Program and One-Time Inspection Program	Consistent with the GALL Report (see SER Section 3.4.2.2.2, item 2)
Steel piping, piping components, and piping elements exposed to raw water (3.4.1.8)	Loss of material due to general, pitting, crevice, and MIC and fouling	Plant-specific	Yes	Not applicable to STP	Not applicable to STP (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 Program and One-Time Inspection Program	Consistent with the GALL Report (see SER Section 3.4.2.2.4, item 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, 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 Program and One-Time Inspection Program	Consistent with the GALL Report (see SER Section 3.4.2.2.4, item 2)
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 (for Buried Piping and Tanks Surveillance) Yes (for Buried Piping and Tanks Inspection)	Not applicable to STP	Not applicable to STP (see SER Section 3.4.2.2.5, item 1)
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 to STP	Not applicable to STP (see SER Section 3.4.2.2.5, item 2)
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	BWR only	Not applicable to PWRs (see SER Section 3.4.2.1.1)
Stainless steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated water > 60 °C (140 °F) (3.4.1.14)	Cracking due to SCC	Water Chemistry and One-Time Inspection	Yes	Water Chemistry Program and One-TIme Inspection Program	Consistent with the GALL Report (see SER Section 3.4.2.2.6)
Aluminum and copper-alloy piping, piping components, and piping elements exposed to treated water (3.4.1.15)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry Program and One-TIme Inspection Program	Consistent with the GALL Report (see SER Section 3.4.2.2.7, item 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 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 Program and One-TIme Inspection Program	Consistent with the GALL Report (see SER Section 3.4.2.2.7, item 1)
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 Program	Consistent with the GALL Report (see SER Section 3.4.2.2.7, item 2)
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 Program and One-Time Inspection Program	Consistent with the GALL Report (see SER Section 3.4.2.2.7, item 3)
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 Program and One-Time Inspection Program	Consistent with the GALL Report (see SER Section 3.4.2.2.8)
Steel tanks exposed to air-outdoor (external) (3.4.1.20)	Loss of material due to general, pitting, and crevice corrosion	Aboveground Steel Tanks	No	Not applicable to STP	Not applicable to STP (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 and SCC	Bolting Integrity	No	Not applicable to STP	Not applicable to STP (see SER Section 3.4.2.1.1)
Steel bolting and closure bolting exposed to air with steam or water leakage, air-outdoor (external), or air-indoor uncontrolled (external) (3.4.1.22)	Loss of material due to general, pitting, and crevice corrosion; loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	No	Bolting Integrity 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 piping, piping components, and piping elements exposed to closed-cycle cooling water > 60 °C (140 °F) (3.4.1.23)	Cracking due to SCC	Closed-Cycle Cooling Water System	No	Not applicable to STP	Not applicable to STP (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	Not applicable to STP	Not applicable to STP (see SER Section 3.4.2.1.1)
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 Program	Consistent with the 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 to STP	Not applicable to STP (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 to STP	Not applicable to STP (see SER Section 3.4.2.1.1)
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 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 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 Program	Consistent with the 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 the 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	Not applicable to STP	Not applicable to STP (see SER Section 3.4.2.1.1)
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	Not applicable to STP	Not applicable to STP (see SER Section 3.4.2.1.1)
Stainless steel heat exchanger components exposed to raw water (3.4.1.33)	Loss of material due to pitting, crevice, and MIC and fouling	Open-Cycle Cooling Water System	No	Not applicable to STP	Not applicable to STP (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	Not applicable to STP	Not applicable to STP (see SER Section 3.4.2.1.1)
Copper alloy > 15% Zn piping, piping components, and piping elements exposed to closed-cycle cooling water, raw water, or treated water (3.4.1.35)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Not applicable to STP	Not applicable to STP (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
Gray cast iron piping, piping components, and piping elements exposed to soil, treated water, or raw water (3.4.1.36)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Not applicable to STP	Not applicable to STP (see SER Section 3.4.2.1.1)
Steel, stainless steel, and Ni-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 Program and One-TIme Inspection Program	Consistent with the GALL Report (see SER Section 3.4.2.1.2)
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 Program	Consistent with the GALL Report (see SER Sections 3.4.2.1.3 and 3.3.2.1.12)
Stainless steel piping, piping components, and piping elements exposed to steam (3.4.1.39)	Cracking due to SCC	Water Chemistry	No	Water Chemistry Program and One-TIme Inspection Program	Consistent with the GALL Report (see SER Section 3.4.2.1.4)
Glass piping elements exposed to air, lubricating oil, raw water, and treated water (3.4.1.40)	None	None	No	Not applicable to STP	Not applicable to STP (see SER Section 3.4.2.1.1)
Stainless steel, copper alloy, and Ni-alloy piping, piping components, and piping elements exposed to air-indoor uncontrolled (external) (3.4.1.41)	None	None	No	None	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to air-indoor controlled (external) (3.4.1.42)	None	None	No	None	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 and stainless steel piping, piping components, and piping elements in concrete (3.4.1.43)	None	None	No	None	Consistent with the 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 the GALL Report

SER Section 3.4.2.1 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. SER Section 3.4.2.2 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. SER Section 3.4.2.3 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 steam and power conversion system components is documented in SER Section 3.0.3.

3.4.2.1 AMR Results That Are Consistent with the GALL Report

LRA Section 3.4.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the steam and power conversion system components:

- Bolting Integrity
- Boric Acid Corrosion, added by letter dated January 18, 2012
- Buried Piping and Tanks Inspection
- External Surfaces Monitoring Program
- Flow-Accelerated Corrosion
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Lubricating Oil Analysis
- One-Time Inspection
- Selective Leaching of Materials, added by letter dated November 30, 2011
- Water Chemistry

LRA Tables 3.4.2-1 through 3.4.2-6 summarize the AMRs for the steam and power conversion system components and indicate AMRs claimed to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant had claimed consistency and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine whether the plant-specific components in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR item. The notes describe how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with notes A through E, which indicate how the AMR was consistent with the GALL Report.

Note A indicates that the AMR 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 confirm 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 audited these items to confirm consistency with the GALL Report and confirmed that it had reviewed and accepted the identified exceptions to the GALL Report AMPs. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report; however, the applicant identified a different component in the GALL Report that had the same material, environment, aging effect, and AMP as the component under review. The staff audited these items to confirm consistency with the GALL Report and 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 audited these items to confirm consistency with the GALL Report and confirmed whether the AMR item of the different component was applicable to the component under review. The staff confirmed whether it had reviewed and accepted the exceptions to the GALL Report AMPs. It also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff audited these items to confirm consistency with the GALL Report and determined whether the identified AMP would manage the aging effect consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

The staff audited and reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did confirm that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluation follows.

On the basis of its audit and review, the staff determines that for AMRs not requiring further evaluation as identified in LRA Table 3.4.1, the applicant's references to the GALL Report are acceptable, and no further staff review is required.

3.4.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.4.1, items 3.4.1.5 and 3.4.1.13, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable because the associated items are only applicable to BWRs. In the applicant's 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 noted that STP is a PWR with a dry ambient containment. Based on this determination, the staff finds these items are not applicable to STP.

LRA Table 3.4.1, item 3.4.1.20, is associated with managing steel tanks exposed to outdoor external air for loss of material due to general, pitting, and crevice corrosion. The applicant stated that this item is not applicable to STP because STP does not have any in-scope steel tanks in the condensate or AFW systems. The staff reviewed LRA Sections 2.3.4 and 3.4, and the UFSAR, and finds that the applicant's statement is acceptable. The staff concluded that this item is not applicable to STP.

LRA Table 3.4.1, item 3.4.1.21, is associated with managing high-strength steel closure bolting exposed to air with steam or water leakage for cracking due to cyclic loading and SCC. The applicant stated that this item is not applicable to STP because STP does not have any in-scope high-strength bolting in steam and power conversion systems. The staff reviewed LRA Sections 2.3.4 and 3.4, and the UFSAR, and finds that the applicant's statement is acceptable. The staff concluded that this item is not applicable to STP.

LRA Table 3.4.1, item 3.4.1.23, is associated with managing stainless steel piping, piping components, and piping elements exposed to CCCW greater than 60 °C (140 °F) for cracking due to SCC. The applicant stated that this item is not applicable to STP because STP does not have any in-scope stainless steel piping, piping components, or piping elements exposed to CCCW in the condensate, blowdown, or AFW systems. The staff reviewed LRA Sections 2.3.4 and 3.4, and the UFSAR, and finds that the applicant's statement is acceptable. The staff concluded that this item is not applicable to STP.

LRA Table 3.4.1, item 3.4.1.24, is associated with managing steel heat exchanger components exposed to CCCW for loss of material due to general, pitting, crevice, and galvanic corrosion. The applicant stated that this item is not applicable to STP because STP does not have any in-scope steel components exposed to CCCW in the feedwater, condensate, blowdown, or AFW systems. The staff reviewed LRA Sections 2.3.4 and 3.4, and the UFSAR, and finds that the applicant's statement is acceptable. The staff concluded that this item is not applicable to STP.

LRA Table 3.4.1, item 3.4.1.26, is associated with managing copper-alloy piping, piping components, and piping elements exposed to CCCW for loss of material due to pitting, crevice, and galvanic corrosion. The applicant stated that this item is not applicable to STP because STP does not have any in-scope copper alloy components exposed to CCCW in the condensate, blowdown, or AFW systems. The staff reviewed LRA Sections 2.3.4 and 3.4, and the UFSAR, and finds that the applicant's statement is acceptable. The staff concluded that this item is not applicable to STP.

LRA Table 3.4.1, item 3.4.1.27, is associated with managing steel, stainless steel, and copper alloy heat exchanger tubes exposed to CCCW for reduction of heat transfer due to fouling. The applicant stated that this item is not applicable to STP because STP does not have any in-scope steel, stainless steel, or copper alloy components exposed to CCCW in the condensate, blowdown, or AFW systems. The staff reviewed LRA Sections 2.3.4 and 3.4, and the UFSAR, and finds that the applicant's statement is acceptable. The staff concluded that this item is not applicable to STP.

LRA Table 3.4.1, item 3.4.1.31, is associated with managing steel heat exchanger components exposed to raw water for loss of material due to general, pitting, crevice, and galvanic corrosion, MIC, and fouling. The applicant stated that this item is not applicable to STP because STP does not have any in-scope components exposed to raw water in the condensate, blowdown, or AFW systems. The staff reviewed LRA Sections 2.3.4 and 3.4, and the UFSAR, and finds that the applicant's statement is acceptable. The staff concluded that this item is not applicable to STP.

LRA Table 3.4.1, item 3.4.1.32, is associated with managing stainless steel and copper-alloy piping, piping components, and piping elements exposed to raw water for loss of material due to pitting, crevice corrosion, and MIC. The applicant stated that this item is not applicable to STP because STP does not have any in-scope components exposed to raw water in the feedwater, condensate, blowdown, or AFW systems. The staff reviewed LRA Sections 2.3.4 and 3.4, and the UFSAR, and finds that the applicant's statement is acceptable. The staff concluded that this item is not applicable to STP.

LRA Table 3.4.1, item 3.4.1.33, is associated with managing stainless steel heat exchanger components exposed to raw water for loss of material due to pitting, crevice corrosion, MIC, and fouling. The applicant stated that this item is not applicable to STP because STP does not have any in-scope components exposed to raw water in the condensate, blowdown, or AFW systems. The staff reviewed LRA Sections 2.3.4 and 3.4, and the UFSAR, and finds that the applicant's statement is acceptable. The staff concluded that this item is not applicable to STP.

LRA Table 3.4.1, item 3.4.1.34, is associated with managing steel, stainless steel, and copper alloy heat exchanger tubes exposed to raw water for reduction of heat transfer due to fouling. The applicant stated that this item is not applicable to STP because STP does not have any in-scope components exposed to raw water in the condensate, blowdown, or AFW systems. The staff reviewed LRA Sections 2.3.4 and 3.4, and the UFSAR, and finds that the applicant's statement is acceptable. The staff concluded that this item is not applicable to STP.

LRA Table 3.4.1, item 3.4.1.35, is associated with managing copper alloy (greater than 15 percent Zn) piping, piping components, and piping elements exposed to CCCW, raw water, or treated water for loss of material due to selective leaching. The applicant stated that this item is not applicable to STP because STP does not have any in-scope copper alloy (greater than 15 percent Zn) piping or piping components or elements in the feedwater, condensate, blowdown, or AFW systems. The staff reviewed LRA Sections 2.3.4 and 3.4, and the UFSAR, and finds that the applicant's statement is acceptable. The staff concluded that this item is not applicable to STP.

LRA Table 3.4.1, item 3.4.1.36, is associated with managing gray cast iron piping, piping components, and piping elements exposed to soil, treated water, or raw water for loss of material due to selective leaching. The applicant stated that this item is not applicable to STP because STP does not have any in-scope gray cast-iron components in the feedwater, condensate, blowdown, or AFW systems. The staff reviewed LRA Sections 2.3.4 and 3.4, and the UFSAR, and finds that the applicant's statement is acceptable. The staff concluded that this item is not applicable to STP.

LRA Table 3.4.1, item 3.4.1.40, is associated with glass piping elements exposed to air, lubricating oil, raw water, and treated water and no aging effect or mechanism. The applicant stated that this item is not applicable to STP because STP does not have any in-scope glass components in the steam and power conversion systems. The staff reviewed LRA Sections 2.3.4 and 3.4, and UFSAR Section 10, and finds that the applicant's statement is acceptable. The staff concluded that this item is not applicable to STP.

3.4.2.1.2 Loss of Material Due to Pitting and Crevice Corrosion

LRA Table 3.4.1, item 3.4.1.37, addresses steel, stainless steel, and nickel-based alloy piping, piping components, and piping elements exposed to steam, which will be managed for loss of material due to pitting and crevice corrosion. For the AMR items that cite generic note E, the LRA credits the Water Chemistry and One-Time Inspection programs to manage the aging effect for steel and stainless steel piping, piping components, piping elements, and tanks. The GALL Report recommends GALL Report AMP XI.M2, "Water Chemistry," to ensure that these aging effects are adequately managed.

GALL Report AMP XI.M2 recommends using water chemistry control to minimize contaminant concentration to manage aging. The staff noted that the Water Chemistry Program and One-Time Inspection Program propose to manage the aging of steel and stainless steel piping, piping components, and piping elements through the use of water chemistry controls to minimize contaminant concentrations along with a one-time visual inspection to confirm the effectiveness of the Water Chemistry Program.

The staff's evaluations of the applicant's Water Chemistry Program and One-Time Inspection Program are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.4, respectively. In its review of components associated with item 3.4.1.37, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Water Chemistry and One-Time Inspection programs acceptable because the Water Chemistry Program establishes the plant water chemistry control parameters and their limits to mitigate aging and identifies the actions required if the parameters exceed the limits, and the One-Time Inspection Program prescribes appropriate visual, volumetric, or other inspection techniques capable of detecting pitting and crevice corrosion prior to loss of intended function to confirm the effectiveness of the water chemistry controls.

The staff concludes that for LRA item 3.4.1.37, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.1.3 Loss of Material Due to Boric Acid Corrosion

LRA Table 3.4.1, item 3.4.1.38, addresses steel bolting and external surfaces exposed to air with borated water leakage, which will be managed for loss of material due to boric acid corrosion. The GALL Report recommends GALL Report AMP XI.M10, "Boric Acid Corrosion," to manage loss of material due to boric acid corrosion for this component group. In the LRA, the applicant originally stated that this item was not applicable, stating that STP had no in-scope components exposed to borated water leakage in steam and power conversion systems.

SER Section 3.3.2.1.12 documents RAIs 3.3.1.88-1 and 3.3.1.88-2, which concern the scope of components to be included in the applicant's AMRs for those exposed to a borated water leakage environment. In its response to RAI 3.3.1.88-2, the applicant revised the LRA to state that Table 3.4.1, item 3.4.1.38, was applicable and included AMRs for several additional components to the LRA that reference this item.

The staff finds the applicant's changes acceptable because the LRA has been revised to include AMR items for appropriate in-scope, susceptible components exposed to an external environment of borated water leakage in the steam and power conversion systems, and the applicant is managing these items in a manner consistent with the GALL Report.

The staff concludes that for LRA item 3.4.1.38, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.1.4 Cracking Due to Stress Corrosion Cracking

LRA Table 3.4.1, item 3.4.1.39, addresses stainless steel piping, piping components, and piping elements exposed to steam, which will be managed for cracking due to SCC. For the AMR item that cites generic note E, the LRA credits the Water Chemistry Program to manage the aging effect. The LRA also credits the One-Time Inspection Program to confirm the effectiveness of the Water Chemistry Program for adequate aging management of cracking. The GALL Report recommends GALL Report AMP XI.M2, "Water Chemistry," to ensure that the aging effect is adequately managed.

GALL Report AMP XI.M2 recommends using preventive measures, including water chemistry control, to manage the aging of these items by limiting the concentrations of chemical species known to cause SCC and controlling dissolved oxygen levels to minimize the environmental effect on SCC. The staff noted that the Water Chemistry Program proposes managing the aging of stainless steel piping, piping components, and piping elements through the use of preventive measures including water chemistry control, and the One-Time Inspection Program provides confirmation of the effectiveness of the Water Chemistry Program to manage cracking. The staff also noted that the applicant's aging management method using the Water Chemistry Program and the One-Time Inspection Program is consistent with the recommendation in SRP-LR, Revision 2, Table 3.4-1, ID 11, and the GALL Report, Revision 2.

The staff's evaluations of the applicant's Water Chemistry Program and One-Time Inspection Program are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.4, respectively. In its review of components associated with item 3.4.1.39, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Water Chemistry Program and One-Time Inspection Program acceptable because the Water Chemistry Program limits the concentrations of chemical species known to cause SCC and controls the dissolved oxygen level to minimize the environmental effect on SCC, and the One-Time Inspection Program provides confirmation of the effectiveness of the Water Chemistry Program so that it is ensured to adequately manage the aging effect due to SCC of the components.

The staff concludes that for LRA item 3.4.1.39, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

LRA Section 3.4.2.2 provides further evaluations of aging management, as recommended by the GALL Report, for the steam and power conversion system components. The applicant provided information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to general, pitting, and crevice corrosion
- loss of material due to general, pitting, crevice, and 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

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluations to determine whether they adequately address those issues and reviewed the applicant's further evaluations against the criteria in SRP-LR Section 3.4.2.2. The staff's review of the applicant's further evaluations follows.

3.4.2.2.1 Cumulative Fatigue Damage

LRA Section 3.4.2.2.1 states that cumulative metal fatigue is a TLAA, as defined in 10 CFR 54.3. An applicant 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.

3.4.2.2.2 Loss of Material Due to General, Pitting, and Crevice Corrosion

Item 1. LRA Section 3.4.2.2.2.1, associated with LRA Table 3.4.1, items 3.4.1.2, 3.4.1.4, and 3.4.1.6, addresses steel piping, piping components, piping elements, tanks, and heat exchangers exposed to treated water and steel piping, piping components, and piping elements exposed to steam, which will be 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 for steel piping, piping components, and piping elements exposed to steam. The SRP-LR also states that the existing program relies on monitoring and control of water chemistry to manage the effect of loss of material. The SRP-LR also states that the effectiveness of the Water Chemistry Program should be confirmed to ensure that corrosion does not occur. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Water Chemistry and One-Time Inspection programs will be used to manage loss of material. The applicant also stated that the One-Time Inspection Program includes inspections of selected components at susceptible locations where contaminants could accumulate.

The applicant stated that for items 3.4.1.2, 3.4.1.3, 3.4.1.4, and 3.4.1.6, the applicability is limited to steel piping, piping components, piping elements, and tanks (treated water only) exposed to steam and treated water. The applicant stated that for items 3.4.1.3 no in-scope steel heat exchanger components exposed to treated water are present in the steam and power conversion systems. The applicant's LRA and UFSAR confirm that no in-scope steel heat exchanger components exposed to treated water are present in the steam and power conversion systems.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection programs are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.4, respectively. The staff finds that the applicant has 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 establishes the plant water chemistry control parameters and their limits to mitigate the potential for aging and identifies the actions required if the parameters exceed the limits, and the One-Time Inspection Program prescribes appropriate visual, volumetric, or other inspection techniques capable of detecting pitting and crevice corrosion prior to loss of intended function in order to confirm the effectiveness of the water chemistry controls.

Based on the programs identified, the staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.4.2.2.2, item 1, for SRP-LR items 3.2-2, 3.2-4, and 3.2-6. For these items associated with LRA Section 3.4.2.2.2.1, 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).

LRA Section 3.4.2.2.2 Item 1, associated with LRA Table 3.4.1, item 3.4.1-3, addresses loss of material due to general, pitting, and crevice 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 in the steam and power conversion systems. The staff reviewed LRA Sections 2.3.4 and 3.4, and the UFSAR and finds that no in-scope steel heat exchanger components exposed to treated water are present in the steam and power conversion systems.

Item 2. LRA Section 3.4.2.2.2.2, associated with LRA Table 3.4.1, item 3.4.1.7, addresses piping, piping components, and piping elements, which will be managed for loss of material due to general, pitting, and crevice corrosion. The criteria in SRP-LR Section 3.4.2.2.2, item 1, recommend the use of GALL Report AMPs XI.M39, "Lubricating Oil Analysis," and XI.M32, "One-Time Inspection," for managing the loss of material due to general, pitting, and crevice corrosion. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Lubricating Oil Analysis Program and the One-Time Inspection Program will be used to manage aging for this item. The applicant also stated that the One-Time Inspection Program would include inspections of selected components at susceptible locations where contaminants (such as water) could accumulate.

The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection programs are documented in SER Sections 3.0.3.2.19 and 3.0.3.1.4, respectively. In its review of components associated with item 3.4.1.7, the staff finds that the applicant meets the further evaluation criteria, and the applicant's proposal to manage aging using the Lubricating Oil Analysis and One-Time Inspection programs is acceptable because 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 selected components at susceptible locations where contaminants such as water could accumulate.

Based on the programs identified, the staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.4.2.2.2, item 2. For those items associated with LRA Section 3.4.2.2.2.2, 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).

3.4.2.2.3 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion and Fouling

LRA Section 3.4.2.2.3, associated with LRA Table 3.4.1, item 3.4.1.8, addresses loss of material due to general, pitting, and crevice corrosion, MIC, and fouling in steel piping, piping components, and piping elements exposed to raw water. The applicant stated that this item is not applicable because there are no in-scope components exposed to raw water in the AFW system. The staff reviewed LRA Sections 2.3.4 and 3.4, and the UFSAR, and finds that no in-scope steel piping, piping components, and piping elements exposed to raw water are present in the steam and power conversion systems.

3.4.2.2.4 Reduction of Heat Transfer Due to Fouling

Item 1. LRA Section 3.4.2.2.4, item 1, associated with LRA Table 3.4.1, item 3.4.1.9, addresses stainless steel and copper heat exchanger tubes exposed to treated water, which will be 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 applicant addressed the further evaluation criteria of the SRP-LR by stating that the Water Chemistry and One-Time Inspection programs manage loss of heat transfer due to fouling for copper alloy components exposed to secondary water. The applicant further stated that the one-time inspection will include selected components at susceptible locations where contaminants could accumulate (e.g., stagnant flow locations). In its review of components associated with item 3.4.1.9, the staff noted that LRA Table 3.4.2-6, "Auxiliary Feedwater System," addresses the stainless steel AFW turbine oil cooler in secondary water environment, which will be managed for reduction of heat transfer due to fouling by the Water Chemistry and the One-Time Inspection programs. However, in its review of LRA Section 3.4, the staff did not find any AMR items for copper alloy heat exchangers, as stated in LRA Section 3.4.2.2.4.1. By letter dated September 22, 2011, the staff issued RAI 3.4.2.2.4-1 asking the applicant to clarify that LRA Section 3.4.2.2.4.1 applies to these stainless steel heat exchangers and to confirm if there are copper alloy heat exchangers in treated water environment with an aging effect of reduction of heat transfer in steam and power conversion systems.

In its response dated November 21, 2011, the applicant stated that the AFW turbine oil cooler components are stainless steel, and there are no copper alloy heat exchanger components in the steam and power conversion systems. The applicant revised LRA Section 3.4.2.2.4.1 to change copper alloy to stainless steel heat exchanger components exposed to secondary water.

The staff finds the applicant's response acceptable because a review of the LRA Section 3.4 and the UFSAR found that there are no copper alloy heat exchanger components in the steam and power conversion systems. The staff's concern described in RAI 3.4.2.2.4-1 is resolved.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection programs are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.4, respectively. In its review of components associated with item 3.4.1.9, the staff finds that the applicant meets the further evaluation criteria and 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 confirm the effectiveness of the chemistry controls by inspecting selected components at susceptible locations where contaminants could accumulate (e.g., stagnant flow locations).

Based on the programs identified, the staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.4.2.2.4, item 1. For those items that apply to LRA Section 3.4.2.2.4, item 1, 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).

Item 2. LRA Section 3.4.2.2.4, item 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 the 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 confirm 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 confirm the effectiveness of the Lubricating Oil Analysis Program to manage loss of heat transfer due to fouling of copper alloy heat exchanger tubes in the feedwater system. The applicant further stated that the one-time inspection will include selected components at susceptible locations where contaminants, such as water, could accumulate.

In its review of components associated with item 3.4.1.10, the staff noted that LRA Table 3.3.2-9 addresses stainless steel heat exchanger (lube oil cooler), and LRA Table 3.4.2-6 addresses stainless steel heat exchanger (AF turbine oil cooler) in lubricating oil environment, which will be managed for reduction of heat transfer due to fouling by the Lubricating Oil Analysis and the One-Time Inspection programs; however, the staff did not find any AMR items for copper alloy heat exchangers, as stated in the LRA Section 3.4.2.2.4.2. By letter dated September 22, 2011, the staff issued RAI 3.4.2.2.4-2 asking the applicant to clarify whether LRA Section 3.4.2.2.4.2 applies to these stainless steel heat exchangers and to confirm whether there are copper alloy heat exchangers in lubricating oil environment with an aging effect of reduction of heat transfer in steam and power conversion systems.

In its response dated November 21, 2011, the applicant stated that the AFW turbine oil cooler components are stainless steel, and there are no copper alloy heat exchanger components in the steam and power conversion systems. The applicant revised LRA Section 3.4.2.2.4.1 to change copper alloy to stainless steel heat exchanger components exposed to lubricating oil.

The staff finds the applicant's response acceptable because a review of the LRA Section 3.4 and the UFSAR found that there are no copper alloy heat exchanger components in the steam and power conversion systems. The staff's concern described in RAI 3.4.2.2.4-2 is resolved.

The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection programs are documented in SER Sections 3.0.3.2.19 and 3.0.3.1.4, respectively. In its review of components associated with item 3.4.1.10, the staff finds that the applicant meets the further review criteria and the applicant's proposal to manage aging using the specified AMPs is 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 confirm the effectiveness of the Lubricating Oil Analysis Program to manage this aging effect.

Based on the programs identified, the staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.4.2.2.4, item 2. For those items that apply to LRA Section 3.4.2.2.4, item 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).

3.4.2.2.5 Loss of Material Due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion

Item 1. LRA Section 3.4.2.2.5.1, associated with LRA Table 3.4.1, item 3.4.1.11, addresses loss of material due to general, pitting, and crevice corrosion, and MIC in steel (with or without coating or wrapping) piping, piping components, and piping elements exposed to soil. The applicant stated that this item is not applicable because the condensate and AFW systems do not contain any in-scope steel (with or without coating or wrapping) piping, piping components, or piping elements that are exposed to soil. The staff reviewed LRA Sections 2.3.4 and 3.4, and the applicant's UFSAR, and confirmed that no in-scope steel (with or without coating or wrapping) piping, piping components, and piping elements exposed to soil are present in the steam and power conversion systems.

Item 2. LRA Section 3.4.2.2.5, item 2, is associated with LRA Table 3.4.1, item 3.4.1.12, and addresses steel heat exchanger components exposed to lubricating oil. The applicant stated that this item is not applicable because there are no in-scope steel heat exchanger tubes exposed to lubricating oil in the AFW system.

The staff reviewed LRA Sections 2.3.4 and 3.4, and the UFSAR, and confirmed that there are no in-scope steel heat exchanger tubes exposed to lubricating oil in the steam and power conversion systems; therefore, it finds the applicant's statement acceptable.

3.4.2.2.6 Cracking Due to Stress-Corrosion Cracking

LRA Section 3.4.2.2.6 is associated with LRA Table 3.4.1, item 3.4.1.14, and addresses stainless steel piping components and tanks exposed to treated water greater than 60 °C (140 °F), which will be 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 state 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 60 °C (140 °F). The SRP-LR also states that the existing AMP relies on monitoring and control of primary water chemistry. The SRP-LR further 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 confirm 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 and the One-Time Inspection Program manage cracking due to SCC for the stainless steel components. LRA Section B2.1.16 states that the One-Time Inspection Program conducts one-time inspections of plant system piping and components to confirm the effectiveness of the Water Chemistry Program.

The staff's evaluations of the applicant's Water Chemistry Program and the One-Time Inspection Program are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.4, respectively. The staff finds that the applicant meets the further evaluation criteria, and the applicant's proposal to manage aging using the Water Chemistry Program and One-Time Inspection Program is acceptable because the Water Chemistry Program limits the concentration of chemical species known to cause SCC and controls the dissolved oxygen level to minimize the environmental effect on SCC, and the One-Time Inspection Program includes a one-time inspection of selected components to confirm the effectiveness of the Water Chemistry Program so that it is ensured to adequately manage cracking due to SCC of the components.

Based on the programs identified, the staff concludes that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.4.2.2.6. For those items that apply to LRA Section 3.4.2.2.6, the staff determines that the LRA is consistent with the GALL Report and that the applicant 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).

3.4.2.2.7 Loss of Material Due to Pitting and Crevice Corrosion

Item 1. LRA Section 3.4.2.2.7.1, associated with LRA Table 3.4.1, items 3.4.1.6, 3.4.1.15, and 3.4.1.16, addresses aluminum, copper, and stainless steel, piping, piping components, and piping elements and stainless steel tanks and heat exchangers exposed to treated water, which will be 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. The SRP-LR further states that the effectiveness of the chemistry control program should be confirmed to ensure that corrosion does not occur. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Water Chemistry and One-Time Inspection programs will manage loss of material in components exposed to secondary and demineralized water. The applicant also stated that the One-Time Inspection Program includes inspections of selected components at susceptible locations where contaminants could accumulate.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection programs are documented in SER Sections 3.0.3.2.1 and 3.0.3.1.4, respectively. Based on 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 meets 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 PWR Water Chemistry Program establishes the plant water chemistry control parameters and their limits to mitigate aging and identifies the actions required if the parameters exceed the limits, and the One-Time Inspection Program prescribes appropriate visual, volumetric, or other inspection techniques capable of detecting pitting and crevice corrosion prior to loss of intended function to confirm the effectiveness of the water chemistry controls.

Based on the programs identified, the staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.4.2.2.7, item 1. For those items associated with LRA Section 3.4.2.2.7.1, 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).

Item 2. LRA Section 3.4.2.2.7.2, associated with LRA Table 3.4.1, item 3.4.1.17, addresses loss of material due to pitting and crevice corrosion in stainless steel piping, piping components, and piping elements exposed to soil. The criteria in SRP-LR Section 3.4.2.2.7, item 2, state that loss of material due to pitting and crevice corrosion may occur in stainless steel piping, piping components, and piping elements exposed to soil. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that the aging effect is adequately managed. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Buried Piping and Tanks Inspection Program manages the loss of material due to general, pitting, and crevice corrosion, and MIC for carbon steel (including cast iron and ductile iron) external surfaces of buried components.

The staff's evaluation of the applicant's Buried Piping and Tanks Inspection Program is documented in SER Section 3.0.3.2.14. The staff noted that the program proposes to manage loss of material of buried piping and piping components through opportunistic and directed inspections. If, during the inspections, adverse indications (e.g., leaks, material thickness less than minimum, and general or local degradation of coatings that exposes the base material) that fail to meet the acceptance criteria are discovered, corrective actions for the repair or replacement of the affected component are required. Based on its review of components associated with item 3.4.1.17, the staff finds that the applicant meets the further evaluation criteria, and the applicant's proposal to manage aging using the Buried Piping and Tanks Inspection Program is acceptable because the program will use directed inspections or suitable alternatives (hydrostatic test or visual inspection of the internal surface) to determine if a loss of material is occurring. In addition, the program contains corrective actions that include repair or replacement if acceptance criteria are not met. The program also includes preventive and mitigative actions to ensure the piping and components are coated, backfilled, and cathodically protected.

Based on the program identified, the staff determines that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.4.2.2.7, item 2. For those items associated with LRA Section 3.4.2.2.7.2, 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).

Item 3. LRA Section 3.4.2.2.7.3 is associated with Table 3.4.1, item 3.4.1.18, and manages copper-alloy piping, piping components, and piping elements exposed to lubricating oil for loss of material due to pitting and crevice corrosion. The SRP-LR criteria state that since control of lubricating oil contaminants may not always have been adequate to preclude corrosion, the effectiveness of lubricating oil contaminant control should be confirmed to ensure that corrosion does not occur. The applicant stated that it will use the Lubricating Oil Analysis and One-Time Inspection programs to manage aging for these components, with the One-Time Inspection Program being used to inspect locations where contaminants could accumulate. The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection programs are documented in SER Sections 3.0.3.2.19 and 3.0.3.1.4, respectively.

In its review of components associated with item 3.4.1.18, the staff finds that the applicant meets the further evaluation criteria, and the applicant's proposal to manage aging using the Lubricating Oil Analysis and One-Time Inspection programs is acceptable because 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 selected components at susceptible locations where contaminants such as water could accumulate.

Based on the programs identified, the staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.4.2.2.7, item 3. For those items associated with LRA Section 3.4.2.2.7.3, 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).

3.4.2.2.8 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 and heat exchanger components exposed to lubricating oil, which are being managed for loss of material due to pitting, crevice corrosion, and MIC 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 corrosion, 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 applicant addressed the further evaluation criteria of the SRP-LR by stating that the Lubricating Oil Analysis and the One-Time Inspection programs manage loss of material due to pitting, crevice corrosion, and MIC for stainless steel components exposed to lubricating oil. The applicant further stated that the one-time inspection will include selected components at susceptible locations where contaminants such as water could accumulate.

The staff's evaluations of the applicant's Lubricating Oil Analysis and One-Time Inspection programs are documented in SER Sections 3.0.3.2.19 and 3.0.3.1.4, respectively. In its review of components associated with item 3.4.1.19, the staff finds that the applicant meets the further evaluation criteria, and the applicant's proposal to manage aging using the specified AMPs is 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 confirm the effectiveness of the Lubricating Oil Analysis Program to manage this aging effect.

Based on the programs identified, the staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.4.2.2.8. For those items that apply to LRA Section 3.4.2.2.8, 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).

3.4.2.2.9 Loss of Material Due to General, Pitting, Crevice, and Galvanic Corrosion

LRA Section 3.4.2.2.9 and Table 3.4.1, item 3.4.1.5, are only applicable to BWRs. Therefore, as stated in SER Section 3.4.2.1.1,this item is not applicable to STP.

3.4.2.2.10 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's QA Program.

3.4.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.4.2-1 through 3.4.2-6, the staff reviewed additional details of AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.4.2-1 through 3.4.2-6, the applicant indicated, via notes F through 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 whether the applicant had demonstrated that the aging effects will be adequately managed so that the intended functions will remain consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

3.4.2.3.1 Steam and Power Conversion System—Summary of Aging Management Evaluation—Main Steam System—LRA Table 3.4.2-1

<u>Calcium Silicate and Fiberglass Insulation Exposed to Plant Indoor Air (External)</u>. As amended by letter dated June 3, 2014, in LRA Tables 3.4.2-1, 3.4.2-3, and 3.4.2-5, the applicant stated that calcium silicate and fiberglass insulation exposed to plant indoor air (external) will be managed for reduced thermal insulation resistance due to moisture intrusion by the External Surfaces Monitoring Program.

The staff noted that although the applicant cited generic note H, LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," provides AMR items to address this material, environment, and aging effect combination. GALL Report AMR item S-403 states that reduced thermal insulation resistance due to moisture intrusion is managed for calcium silicate and fiberglass insulation exposed to plant indoor air (external), by GALL Report AMP XI.M36.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.16. The staff finds the applicant's proposal to manage aging using the External Surfaces Monitoring Program acceptable because periodic visual inspections of the insulation jacketing will be conducted to verify that the insulation is water-tight.

Aluminum Valves Exposed to Lubricating Oil. In LRA Table 3.4.2-1, the applicant stated that aluminum valves exposed to lubricating oil will be managed for loss of material by the Lubricating Oil Analysis and One-Time Inspection AMPs. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noted that the GALL Report does not address aluminum valves exposed to lubricating oil for loss of material. However, the staff noted that the GALL Report does address aluminum piping and piping components exposed to lubricating oil for loss of material. Based on its review of the GALL Report and the ASM Handbook, both of which state that loss of material in the form of pitting and crevice corrosion may occur in this environment, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

Aluminum Solenoid Valves Exposed to Lubricating Oil. In LRA Table 3.4.2-1, the applicant stated that aluminum solenoid valves exposed to lubricating oil will be managed for loss of material by the Lubricating Oil Analysis and One-Time Inspection AMPs. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noted that the GALL Report does not address aluminum solenoid valves exposed to lubricating oil for loss of material. However, the staff noted that the GALL Report does address aluminum piping and piping components exposed to lubricating oil for loss of material. Based on its review of the GALL Report and the ASM Handbook, both of which state that loss of material in the form of pitting and crevice corrosion may occur in this environment, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

Conclusion. 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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.3.2 Steam and Power Conversion System—Summary of Aging Management Evaluation—Auxiliary Steam System and Boilers—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 system and boilers component groups.

Copper Alloy (Greater than 15 Percent Zinc) Solenoid Valve Exposed to Plant Indoor Air. The staff's evaluation for copper alloy (greater than 15 percent Zn) solenoid valves internally exposed to plant indoor air, which will be managed for loss of material by the Selective Leaching of Materials Program and cite generic note G, is documented in SER Section 3.3.2.3.7.

3.4.2.3.3 Steam and Power Conversion System—Summary of Aging Management Evaluation—Feedwater System—LRA Table 3.4.2-3

The staff's evaluation for calcium silicate and fiberglass insulation exposed to plant indoor air (external), which will be managed for reduced thermal insulation resistance due to moisture intrusion by the External Surfaces Monitoring Program and cite generic note H, is documented in SER Section 3.4.2.3.1.

Closure Bolting Stainless Steel Exposed to Plant Indoor Air. In LRA Tables 3.4.2-3, 3.4.2-4, 3.4.2-5, and 3.4.2-6, the applicant stated that the stainless steel closure bolting exposed to plant indoor air will be managed for loss of preload by the Bolting Integrity Program. The AMR items cite generic note H. Items associated with closure bolting cite plant-specific note 1, which states that loss of preload is conservatively applied for all closure bolting.

The staff noted that this material and environment combination was not identified in the GALL Report, Revision 1; however, several items (e.g., RP-46, AP-124) in GALL Report, Revision 2, address stainless steel closure bolting exposed to air-indoor uncontrolled, which is consistent with the applicant's plant indoor air environment, and recommend GALL Report AMP XI.M18, "Bolting Integrity," to manage loss of preload. The staff noted that the applicant does not have AMR items for stainless steel closure bolting exposed to plant indoor air being managed for loss of material in LRA Tables 3.4.2-3, 3.4.2-4, 3.4.2-5, and 3.4.2-6. Given that the applicant's definition of plant indoor air is inclusive of condensation and air-indoor uncontrolled, as stated in LRA Table 3.0-1, GALL Report, Revision 2, items (such as SP-84) recommend that loss of material be managed by GALL Report AMP XI.M18 for this component, material, and environment combination.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.5. The staff finds the applicant's proposal to manage loss of preload using the Bolting Integrity Program acceptable because it includes bolting assembly and maintenance controls such as application of appropriate gasket alignment, torque, lubricants, and preload; and it inspects bolted connections to ensure detection of leakage occurs before the leakage becomes excessive. In regard to the applicant not identifying pitting and crevice corrosion as an applicable aging effect, the staff finds this acceptable because the GALL Report recommends that AMP XI.M19, "Bolting Integrity," be used to manage this aging effect. The applicant is already using this program to manage the loss of preload aging effect. The walkdown inspections used to manage loss of preload are the same as for loss of material, and the acceptance criteria related to joint leakage is the same. Given discovery of leakage, it is immaterial whether it is caused by loss of preload or loss of material—either aging effect would result in the joint being addressed by the applicant's CAP. Therefore, the AMP XI.M18 criterion of detecting bolted joint leakage prior to leakage becoming excessive is met regardless of the aging effect, given that all the bolted joints will have the appropriate inspections.

Conclusion. 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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.3.4 Steam and Power Conversion System—Summary of Aging Management Evaluation—Demineralized Water (Make-up) System—LRA Table 3.4.2-4

The staff's evaluation for stainless steel closure bolting exposed to plant indoor air, which will be managed for loss of preload by the Bolting Integrity Program and cite generic note H, is documented in 3.4.2.3.3.

Closure Bolting Carbon Steel Exposed to Atmosphere and Weather. In LRA Table 3.4.2-4, the applicant stated that the carbon steel closure bolting exposed to atmosphere and weather will be managed for loss of preload by the Bolting Integrity Program. The AMR items cite generic note H. Items associated with closure bolting cite plant-specific note 1, which states that loss of preload is conservatively applied for all closure bolting.

The staff noted that this material and environment combination was not identified in the GALL Report, Revision 2; however, several items (e.g., SP-151) in GALL Report, Revision 2, address steel closure bolting exposed to air-outdoor, which is consistent with the applicant's atmosphere and weather environment, and recommend GALL Report AMP XI.M18, "Bolting Integrity," to manage loss of preload. The applicant addressed the GALL Report identified aging effects for this component, material, and environment combination in AMR items in LRA Table 3.4.2-4.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.5. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because it includes bolting assembly and maintenance controls such as application of appropriate gasket alignment, torque, lubricants, and preload, and it inspects bolted connections to ensure detection of leakage occurs before the leakage becomes excessive.

Stainless Steel Piping, Valves, Tanks, and Hatches Exposed to Atmosphere and Weather. In LRA Tables 3.4.2-4 and 3.4.2-6, the applicant stated that for stainless steel piping, valves, tanks, and hatches exposed to atmosphere and weather, 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 to confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff noted that the applicant's LRA submittal was based on Revision 1 of the GALL Report, which does not include the material and environment combination of stainless steel and outdoor air. However, the combination of stainless steel exposed to outdoor air was added to Revision 2 of the GALL Report, which was issued after the applicant's LRA submittal. Revision 2 of the GALL Report states that cracking due to SCC and loss of material due to pitting and crevice corrosion could occur in stainless steel components exposed to outdoor air. Revision 2 of the SRP-LR, Sections 3.4.2.2.2 and 3.4.2.2.3, state that cracking due to SCC and loss of material due to pitting and crevice corrosion could occur for stainless steel piping, piping components, piping elements, and tanks exposed to outdoor air and that these aging effects are only known to occur in environments containing sufficient halides (primarily chlorides) and in which condensation or deliquescence is possible. Revision 2 of the GALL Report recommends further evaluation to determine whether an AMP is needed to manage these aging effects based on the environmental conditions applicable to the plant. By letter dated September 22, 2011, the staff issued RAI 3.3.2.3.17-1 requesting that the applicant provide an evaluation of whether an AMP is needed to manage cracking due to SCC and loss of material due to pitting and crevice corrosion in stainless steel components exposed to outdoor air (atmosphere and weather), as recommended in Revision 2 of the GALL Report.

In its response dated November 21, 2011, the applicant stated that the prevailing outdoor air is not an aggressive halide-rich environment because the plant is not within 5 miles of a saltwater coastline, there are no roads treated with salt in the winter within ½ mile of the plant, the soil does not contain more than trace chlorides, there are no chlorine treated water sources nearby, there is no runoff from cattle farms, and there is no industry pollution at the site. The applicant also stated that local rains tend to wash outside surfaces of components rather than concentrate contaminants and that its review of plant operating experience found no occurrences of aging of stainless steel components exposed to outdoor air. The staff finds the applicant's response, and its proposal that stainless steel components exposed to outdoor air have no AERMs, acceptable because outdoor environmental conditions at the applicant's plant are not conducive to aging of stainless components, as described in Revision 2 of the GALL Report and the SRP-LR. The staff's concern described in RAI 3.3.2.3.17-1 is resolved.

Stainless Steel Piping Exposed to Demineralized Water. In LRA Table 3.4.2-4 the applicant stated that stainless steel piping exposed to demineralized water will be managed for wall thinning by the Flow-Accelerated Corrosion Program. The AMR item cites generic note H.

The staff noted that this material and environment combination is identified in the GALL Report, which addresses stainless steel piping exposed to demineralized water and recommends the Water Chemistry Program to manage for the loss of material aging effect. However, the applicant identified wall thinning as an additional aging effect, with the associated AMP being its Flow-Accelerated Corrosion Program. The applicant addressed the GALL Report identified aging effects for this component, material, and environment combination in AMR items in LRA Table 3.4.2-4.

The staff's evaluation of the applicant's Flow-Accelerated Corrosion Program is documented in SER Section 3.0.3.2.4. The staff noted that, in response to RAI B2.1.6-1a, the applicant revised the program to include aging management of wall thinning due to mechanisms other than flow-accelerated corrosion. The staff finds the applicant's proposal to manage aging using the Flow-Accelerated Corrosion Program acceptable because the detection, monitoring, and acceptance criteria for the additional wall thinning mechanisms are the same as for flow-accelerated corrosion, and the program includes guidance for inspection and selection of components that are susceptible to wall thinning due to mechanisms other than flow-accelerated corrosion.

Stainless Steel Components Exposed to Plant Indoor Air or Atmosphere/Weather (External). In LRA Tables 3.4.2-4 and 3.4.2-6, as modified by letter dated June 3, 2014, the applicant stated that stainless steel piping and valves externally exposed to indoor air or atmosphere/weather will be managed for loss of material by the External Surfaces Monitoring Program. The AMR items cite generic note H and plant-specific note 3. The AMR items align to AMR item VII.A2.A-405 in LR-ISG-2012-02, which may be used to manage loss of material in insulated stainless steel components exposed to condensation. The staff notes that the GALL Report item cited by the applicant recommends the GALL Report AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” to manage this aging effect.

The staff’s evaluations of the applicant’s External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.16. The staff notes that the applicant modified the AMP, by letter dated June 3, 2014, to specifically address the issues discussed in LR-ISG-2012-02. The staff finds the applicant’s proposal to manage loss of material in insulated stainless steel components, using the External Surfaces Monitoring Program, acceptable because periodic inspections for damage to the insulation jacketing that could allow moisture in-leakage will result in insulation removal for inspection of the component exterior surface.

Conclusion. 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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.3.5 Steam and Power Conversion System—Summary of Aging Management Evaluation—Steam Generator Blowdown System—LRA Table 3.4.2-5

The staff’s evaluation for stainless steel closure bolting exposed to plant indoor air, which will be managed for loss of preload by the Bolting Integrity Program and cites generic note H, is documented in 3.4.2.3.3.

The staff’s evaluation for calcium silicate and fiberglass insulation exposed to plant indoor air (external), which will be managed for reduced thermal insulation resistance due to moisture intrusion by the External Surfaces Monitoring Program and cite generic note H, is documented in SER Section 3.4.2.3.1.

Conclusion. 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 functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.3.6 Steam and Power Conversion System—Summary of Aging Management Evaluation—Auxiliary Feedwater System—LRA Table 3.4.2-6

The staff’s evaluation for stainless steel closure bolting exposed to plant indoor air, which will be managed for loss of preload by the Bolting Integrity Program and cites generic note H, is documented in SER Section 3.4.2.3.3.

The staff’s evaluation for stainless steel components exposed to plant outdoor air (atmosphere and weather) for which the LRA states there is no AERM and no AMP is needed, citing generic note G or H, is documented in SER Section 3.4.2.3.4.

The staff’s evaluation for stainless steel piping and valves externally exposed to atmosphere/weather, which will be managed for loss of material by the External Surfaces Monitoring Program and cite generic note H, is documented in SER Section 3.4.2.3.4.

Closure Bolting Stainless Steel Exposed to Atmosphere and Weather. In LRA Table 3.4.2-6, the applicant stated that the stainless steel closure bolting exposed to atmosphere and weather will be managed for loss of preload by the Bolting Integrity Program. The AMR items cite generic note H. Items associated with closure bolting cite plant-specific note 1, which states that loss of preload is conservatively to be applicable for all closure bolting.

The staff noted that this material and environment combination was not identified in the GALL Report, Revision 1; however, several items (i.e., EP-115, AP-263, SP-151) in GALL Report, Revision 2, address stainless steel closure bolting exposed to air-outdoor, which is consistent with the applicant's atmosphere and weather environment, and recommend GALL Report AMP XI.M18, "Bolting Integrity," to manage loss of preload. The staff noted that the applicant did not address loss of material for the stainless steel closure bolting. The staff also noted that SRP-LR Section 3.4.2.2.2, Revision 2, states that cracking due to SCC could occur for stainless steel piping, piping components, piping elements, and tanks exposed to outdoor air. It also states that cracking is only known to occur in environments containing sufficient halides (primarily chlorides) and in which condensation or deliquescence is possible. It further lists environmental conditions (e.g., plant located close to saltwater, roads that are treated for ice) that could result in exposure to halides and result in SCC. By letter dated September 22, 2011, the staff issued RAI 3.3.2.3.17-1 requesting that the applicant provide an evaluation to determine if the local environmental conditions could result in SCC or loss of material. The staff's evaluation of this RAI is documented in SER Section 3.4.2.3.4.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.5. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because it includes bolting assembly and maintenance control such as application of appropriate gasket alignment, torque, lubricants, and preload; and it inspects bolted connections to ensure detection of leakage before the leakage becomes excessive. In addition, the staff finds the applicant's proposal to not include loss of material as an aging effect acceptable because, as stated by the applicant in its reply to RAI 3.3.2.3.17-1, there are no environmental sources of halides in the vicinity of the plant that would cause SCC or loss of material. The staff's concern described in RAI 3.3.2.3.17-1 is resolved.

Stainless Steel Tank Exposed to Concrete. As amended by letter dated November 4, 2011, LRA Table 3.4.2-6 states that a stainless steel tank exposed to concrete will be managed for loss of material by the Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The AMR item cites generic note G. This item also cites plant-specific note 5, which states that "[a] visual inspection of the external surface of the bottom of tanks sitting directly on soil or concrete cannot be performed. A volumetric examination from the inside of the bottom of the tank is performed in lieu of an external inspection."

During the AMP audit, the staff noted that LRA Table 3.4.2-6 states that the stainless steel tank exposed to atmosphere and weather has no proposed AERM or AMP. The staff performed a walkdown of the AFST with the applicant. Due to walkdown limitations, it was not clear to the staff if all penetrations in the concrete of the AFW concrete stainless steel lined storage tank are caulked. By letter dated August 15, 2011, the staff issued RAI B2.1.20-5 requesting that the applicant state whether all penetrations through the concrete of the AFW concrete stainless steel lined storage tank that could allow water to enter between the tank lining material and the concrete are caulked or sealed. The staff also asked the applicant to state the basis for not conducting tank bottom thickness measurements for the AFST.

In its responses dated September 15, 2011, and November 4, 2011, the applicant stated that LRA Table 3.4.2-6 was revised to add an item—stainless steel tank exposed to concrete—being managed for loss of material by the Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The AFST penetrations are not caulked because any gaps or spaces on the tank exterior and around penetrations are grouted to prevent water entry. The tank bottom will be volumetrically inspected from the inside of the tank by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, and the volumetric inspections will be conducted within 5 years prior to entering the period of extended operation and whenever the tanks are drained.

The staff found the applicant's response to be partially acceptable because the tank penetrations are grouted to prevent leakage of water between the tank stainless steel material and concrete, and volumetric examinations of the tank's bottom will occur within 5 years prior to entering the period of extended operation and whenever the tanks are drained. However, the staff could not find any AMR items in the LRA that require periodic monitoring of the grouting for degradation that could lead to leakage. The staff's concern described in RAI B2.1.20-5 was not completely resolved. By letter dated December 6, 2011, the staff issued RAI B2.1.20-5A requesting that the applicant state why periodic inspections of the grout are not needed to ensure that the grout is not degrading.

In its response dated January 5, 2012, the applicant stated that based on a walkdown of the AFSTs, it confirmed that grout was not used around the piping penetrations, and the concrete shell around the tank tightly adheres to the piping with no gaps for water entry. The applicant further stated that the Structures Monitoring Program will be used to age manage the concrete interface.

The staff finds the applicant's response acceptable because no grout was used and the concrete tightly adheres to piping penetrations. By this point in life (i.e., at least 22 years) any construction shrinkage or separation would have been expected to occur. Based on the response to RAI B2.1.32-2, documented in SER Section 3.0.3.2.26, visual inspections to detect degradation of the pipe to concrete interface will be conducted every 5 years by the Structures Monitoring Program. The staff's concern described in RAI B2.1.20-5A is resolved.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the GALL Report, Revision 2, item SP-137, which states that stainless steel tanks exposed to concrete should be managed for loss of material due to pitting and crevice corrosion, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff's evaluations of the applicant's Internal Surfaces in Miscellaneous Piping and Ducting Components Program and Structures Monitoring Program are documented in SER Sections 3.0.3.2.18 and 3.0.3.2.26, respectively. The staff finds the applicant's proposal to manage aging using the Internal Surfaces in Miscellaneous Piping and Ducting Components Program and Structures Monitoring Program acceptable because the tank bottom will be volumetrically inspected from the inside of the tank by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program within 5 years prior to entering the period of extended operation and whenever the tanks are drained, and the Structures Monitoring Program will conduct visual inspections that are capable of detecting degradation of the piping penetration to concrete interface joint. Volumetric tank bottom inspections are capable of confirming that no degradation is occurring on the tank's surface due to potential water leakage, which is consistent with GALL Report AMP XI.M29, "Aboveground Metallic Tanks."

Stainless Steel Tank Exposed to Atmosphere and Weather (External). In LRA Table 3.4.2-6, the applicant stated that for a stainless steel tank exposed to atmosphere and weather (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 could not confirm that the applicant had identified all credible aging effects that are applicable for this component, material, and environment combination. The staff noted that SRP-LR Section 3.4.2.2.2, Revision 2, states that cracking due to SCC could occur for stainless steel piping, piping components, piping elements, and tanks exposed to outdoor air. It also states that cracking is only known to occur in environments containing sufficient halides (primarily chlorides) and in which condensation or deliquescence is possible. It further lists environmental conditions (e.g., plant located close to saltwater, roads that are treated for ice) that could result in exposure to halides and result in SCC. By letter dated September 22, 2011, the staff issued RAI 3.3.2.3.17-1 requesting that the applicant provide an evaluation to determine if local environmental conditions could result in SCC or loss of material. The staff's evaluation of this RAI is documented in SER Section 3.4.2.3.4.

The staff finds the applicant's proposal acceptable because, as stated by the applicant in its reply to RAI 3.3.2.3.17-1, there are no environmental sources of halides in the vicinity of the plant that could cause SCC or loss of material. The staff's concern described in RAI 3.3.2.3.17-1 is resolved.

Steel Piping, Piping Components, and Piping Elements Exposed to Steam or Treated Water. During its review, the staff noted an apparent inconsistency related to the AFW system, in that there were no AMR results for flow-accelerated corrosion of piping and piping components in the AFW system, although instances of wall thinning due to flow-accelerated corrosion were cited in plant-specific operating experience. The staff found that further information was needed to complete its determination 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. By letter dated September 22, 2011, the staff issued RAI 3.4.2.6-1 requesting that the applicant provide technical information that supports the omission of piping and piping components in the AFW system from coverage by the Flow-Accelerated Corrosion Program.

In its response dated November 21, 2011, the applicant stated that its system susceptibility evaluation for the Flow-Accelerated Corrosion Program initially had not identified components in the AFW system as being susceptible, due to infrequent operation; however, some components in that system are now included in the program after identifying wall thinning. Consequently, the applicant revised Table 3.4.2-6 and Section 3.4.2.1.6 for the AFW system to add an item identifying carbon steel piping with an aging effect of wall thinning managed by the Flow-Accelerated Corrosion Program. The staff finds the applicant's response acceptable because the applicant amended Table 3.4.2-6 to include components that are being managed by the Flow-Accelerated Corrosion Program. The staff's concern in RAI 3.4.2.6-1 is resolved. The staff's evaluation of the Flow-Accelerated Corrosion Program is documented in SER Section 3.0.3.2.4.

Aluminum Filter Exposed to Lubricating Oil. In LRA Table 3.4.2-6, the applicant stated that aluminum filters exposed to lubricating oil will be managed for loss of material by the Lubricating Oil Analysis and One-Time Inspection AMPs. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noted that the GALL Report does not address aluminum filters exposed to lubricating oil for loss of material. However, the staff noted that the GALL Report does address aluminum piping and piping components exposed to lubricating oil for loss of material. Based on its review of the GALL Report and the ASM Handbook, both of which state that loss of material in the form of pitting and crevice corrosion may occur in this environment, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

Stainless Steel Piping, Tubing, and Valves Externally Exposed to Atmosphere/Weather. In LRA Table 3.4.2-6, the applicant stated that stainless steel piping, tubing, and valves externally exposed to atmosphere/weather will be managed for cracking by the External Surfaces Monitoring Program. The AMR items cite generic note H, with plant-specific note 7, which references a new GALL Report item, VII.A2.A.405, that was established in LR-ISG-2012-02 for managing cracking in insulated stainless piping exposed to condensation. The AMR items align to AMR item VII.A2.A-405 in LR-ISG-2012-02, which may be used to manage loss of material in insulated stainless steel components exposed to condensation. The staff notes that the GALL Report item cited by the applicant recommends the External Surfaces Monitoring of Mechanical Components AMP to manage this aging effect.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.16. The staff notes that the applicant modified the AMP in the applicant's letter of June 3, 2014, and specifically addressed the issues discussed in LR-ISG-2012-02. The staff finds the applicant's proposal to manage loss of material in insulated stainless steel components, using the External Surfaces Monitoring Program, acceptable because periodic inspections for damage to the insulation jacketing that could allow moisture in-leakage will result in insulation removal for inspection of the component exterior surface.

Conclusion. 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 functions will remain consistent with the CLB during 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 system components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will remain 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, components, and component groups:

- containment building
- control room
- diesel generator building
- turbine generator building
- mechanical-electrical auxiliary building
- miscellaneous yard areas and buildings (in-scope)
- electrical foundations and structures
- fuel handling building
- ECW structures
- AFW storage tank foundation and shell
- supports

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 operating experience review included industry sources, a review of the GALL Report, and operating experience issues identified since the issuance of the GALL Report.

3.5.2 Staff Evaluation

The staff reviewed LRA Section 3.5 to determine whether the applicant 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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff conducted an onsite audit to examine the applicant’s AMPs and related documentation to confirm the applicant’s claims that certain AMPs were consistent with the corresponding GALL Report AMPs. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did confirm 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 confirm 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 non-aggressive. A plant-specific program is to be evaluated if environment is aggressive.	Yes, plant-specific if environment aggressive	ASME Section XI, Subsection IWL Program. For inaccessible concrete, groundwater chemistry is monitored and opportunistic inspections are performed whenever inaccessible concrete is exposed.	Consistent with the GALL Report (see SER Section 3.5.2.2.1.1)
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 the GALL Report; dewatering system is not used (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, subfoundation (3.5.1.3)	Reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundation	Structures Monitoring Program. If a dewatering system is relied upon to control erosion of cement from porous concrete subfoundations, then the 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	Not applicable; no porous concrete foundations exist (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	No containment related concrete elements are above the allowable limits of ~66 °C (150 °F) general and ~93 °C (200 °F) local (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—BWR only
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.	ASME Section XI, Subsection IWE and 10 CFR 50, Appendix J, programs	ASME Section XI, Subsection IWE Program consistent with exceptions to the GALL Report and 10 CFR 50, Appendix J, Program consistent with the GALL Report (see SER Section 3.5.2.2.1.4)

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
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.	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Loss of prestress is a TLAA (see SER Section 3.5.2.2.1.5)
Steel and stainless steel elements: vent line, vent header, vent line bellows, and downcomers (3.5.1.8)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes, TLAA.	Not applicable	Not applicable—BWR only
Steel, stainless steel elements, dissimilar metal welds: penetration sleeves, penetration bellows; suppression pool shell, unbraced downcomers (3.5.1.9)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes, TLAA.	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Fatigue of metal components is a TLAA (see SER Section 3.5.2.2.1.6)
Stainless steel penetration sleeves, penetration bellows, dissimilar metal welds (3.5.1.10)	Cracking due to SCC	ISI (IWE) and 10 CFR Part 50, Appendix J, and additional appropriate examinations/ evaluations for bellows assemblies and dissimilar metal welds	Yes, detection of aging is to be evaluated.	Not applicable to STP	Not applicable to STP (see SER Section 3.5.2.2.1, item 7)
Stainless steel vent line bellows (3.5.1.11)	Cracking due to SCC	ISI (IWE) and 10 CFR Part 50, Appendix J, and additional appropriate examination/ evaluation for bellows assemblies and dissimilar metal welds	Yes, detection of aging is to be evaluated.	Not applicable	Not applicable—BWR only
Steel, stainless steel elements, dissimilar metal welds: penetration sleeves, penetration bellows, suppression pool shell, unbraced downcomers (3.5.1.12)	Cracking due to cyclic loading	ISI (IWE) and 10 CFR Part 50, Appendix J, and supplemented to detect fine cracks	Yes, detection of aging is to be evaluated.	ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J, programs	Fatigue of metal components is a TLAA (see SER Section 3.5.2.2.1.8)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel, stainless steel elements, dissimilar metal welds: torus, vent line, vent header, vent line bellows, downcomers (3.5.1.13)	Cracking due to cyclic loading	ISI (IWE) and 10 CFR Part 50, Appendix J, and supplemented to detect fine cracks	Yes, detection of aging is to be evaluated.	Not applicable	Not applicable—BWR only
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-in./yr) (NUREG-1557).	Yes, for inaccessible areas of plants located in moderate to severe weathering conditions.	ASME Section XI, Subsection IWL Program	Consistent with the GALL Report (see SER Section 3.5.2.2.1.9)
Concrete elements: walls, dome, basemat, ring girder, buttresses, containment, concrete fill-in annulus (as applicable) (3.5.1.15)	Cracking due to expansion and reaction with aggregate; increase in porosity, permeability due to leaching of calcium hydroxide	ISI (IWL) for accessible areas. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R.	Yes, if concrete was not constructed as stated in inaccessible areas.	ASME Section XI, Subsection IWL Program for accessible areas	Consistent with the GALL Report (see SER Section 3.5.2.2.1.10)
Seals, gaskets, and moisture barriers (3.5.1.16)	Loss of sealing and leakage through containment due to deterioration of joint seals, gaskets, and moisture barriers (caulking, flashing, and other sealants)	ISI (IWE) and 10 CFR Part 50, Appendix J	No	ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J, programs	ASME Section XI, Subsection IWE Program consistent with exceptions to the GALL Report and 10 CFR Part 50, Appendix J, Program consistent with the 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	ISI 10 CFR Part 50, Appendix J, Program and Plant TS	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 penetration sleeves and dissimilar metal welds; personnel airlock, equipment hatch, and CRD hatch (3.5.1.18)	Loss of material due to general, pitting, and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	No	ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J, programs	ASME Section XI, Subsection IWE Program consistent with exceptions to the GALL Report and 10 CFR Part50, Appendix J, Program consistent with the 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—BWR only
Steel elements: suppression chamber liner (interior surface) (3.5.1.20)	Loss of material due to general, pitting, and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	No	Not applicable	Not applicable—BWR only
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—BWR only
Prestressed containment: tendons and anchorage components (3.5.1.22)	Loss of material due to corrosion	ISI (IWL)	No	ASME Section XI, Subsection IWL Program	Consistent with the GALL Report
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	Consistent with the GALL Report (see SER Section 3.5.2.2.2.1)
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	Consistent with the GALL Report (see SER Section 3.5.2.2.2.1)

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
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	Consistent with the GALL Report (see SER Section 3.5.2.2.2.1)
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-in./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 the GALL Report (see SER Section 3.5.2.2.2.1)
All Groups except Group 6: accessible and inaccessible interior and 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	Consistent with the GALL Report (see SER Section 3.5.2.2.2.2)

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.	Structures Monitoring Program	Consistent with the GALL Report (see SER Section 3.5.2.2.2.2)
Groups 1-3, 5-9: foundation (3.5.1.29)	Reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundation	Structures Monitoring Program. If a dewatering system is relied upon for control of settlement, then the 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; no porous concrete foundations exist (see SER Section 3.5.2.2.2.2)
Group 4: radial beam seats in BWR drywell; RPV support shoes for PWR with nozzle supports; SG 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.	Not applicable to STP	Not applicable; Lubrite® was not used on RPV support shoes or SG supports (see SER Section 3.5.2.2.2.1)
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	Consistent with the GALL Report (see SER Section 3.5.2.2.2.2.4)

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
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.	Consistent with the GALL Report (see SER Section 3.5.2.2.2.2.5)
Groups 1-5: concrete (3.5.1.33)	Reduction of strength and modulus due to elevated temperature	A plant-specific AMP is to be evaluated.	Yes, plant-specific if temperature limits are exceeded.	A plant-specific AMP	No Groups 1-5 concrete elements are above the allowable limits of ~66 °C (150 °F) general and ~93 °C (200 °F) local (see SER Section 3.5.2.2.2.3)
Group 6: concrete; all (3.5.1.34)	Increase in porosity and permeability, cracking, and loss of material due to aggressive chemical attack; cracking, loss of bond, and 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. 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.	Water-Control Structures Inspection Program	Consistent with the GALL Report (see SER Section 3.5.2.2.2.4.1)

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
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-in./yr) (NUREG-1557).	Yes, for inaccessible areas of plants located in moderate to severe weathering conditions.	Water-Control Structures Inspection Program	Consistent with the GALL Report (see SER Section 3.5.2.2.2.4.2)
Group 6: all accessible and inaccessible reinforced concrete (3.5.1.36)	Cracking due to expansion/ reaction with aggregates	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.	Water Control Structures Inspection Program	Consistent with the GALL Report (see SER Section 3.5.2.2.2.4.3)
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.	Water Control Structures Inspection Program	Consistent with the GALL Report (see SER Section 3.5.2.2.2.4.3)

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
Groups 7, 8: tank liners (3.5.1.38)	Cracking due to SCC; loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated	Yes	Not applicable	Not applicable; in-scope tank liners evaluated as tanks with their mechanical systems and assigned the GALL Report lines from Chapters VII and VIII (see SER Section 3.5.2.2.2.5)
Support members, welds, bolted connections, and 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 the GALL Report (see SER Section 3.5.2.2.2.6)
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	Consistent with the GALL Report (see SER Section 3.5.2.2.2.6)
Vibration isolation elements (3.5.1.41)	Reduction or loss of isolation function radiation hardening, temperature, humidity, and sustained vibratory loading	Structures Monitoring Program	Yes, if not within the scope of the applicant's Structures Monitoring Program.	Not applicable to STP	Not applicable; no vibration isolation elements in-scope for license renewal (see SER Section 3.5.2.2.2.6)
Groups B1.1, B1.2, and B1.3: support members: anchor bolts and welds (3.5.1.42)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes, TLAA	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Fatigue of metal components is a TLAA (see SER Section 3.5.2.2.2.7)
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	Consistent with the GALL Report for material, environment, and aging effect; Fire Protection Program credited (see SER Section3.5.2.1.2)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
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 the GALL Report
Group 6: exterior above- and below-grade concrete foundation; interior slab (3.5.1.45)	Loss of material due to abrasion, cavitation	Inspection of Water-Control Structures or FERC/U.S. Army Corps of Engineers dam inspections and maintenance	No	Water Control Structures Inspection Program	Consistent with the GALL Report
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 in accordance with TS and leakage from the leak chase channels.	No	Water Chemistry Program and monitoring spent fuel pool water level in accordance with TS and leakage from leak chase channels.	Consistent with the GALL Report (see SER Section 3.5.2.1.5)
Group 6: all metal structural members (3.5.1.47)	Loss of material due to general (steel only), pitting, and crevice corrosion	Inspection of Water-Control Structures or FERC/U.S. Army Corps of Engineers dam inspections and maintenance. If protective coatings are relied upon to manage aging, protective coating monitoring and maintenance provisions should be included.	No	Structures Monitoring Program	Consistent with the GALL Report for material, environment, and aging effect; Structures Monitoring Program credited (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, and seepage	Inspection of Water-Control Structures or FERC/U.S. Army Corps of Engineers dam inspections and maintenance programs	No	Water-Control Structures Inspection Program	Consistent with the GALL Report
Support members, welds, bolted connections, and support anchorage to building structure (3.5.1.49)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and ISI (IWF)	No	Not applicable	Not applicable—BWR only

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 the GALL Report, except for ASME Code Class 1 and 2 supports evaluated under ASME Section XI, Subsection IWF Program (see SER Section 3.5.2.1.3)
Group B1.1: high-strength low-alloy bolts (3.5.1.51)	Cracking due to SCC; loss of material due to general corrosion	Bolting Integrity Program	No	Bolting Integrity and ASME Section XI, Subsection IWF programs	Consistent with the GALL Report (see SER Section 3.5.2.1.6)
Groups B2 and B4: sliding support bearings and sliding support surfaces (3.5.1.52)	Loss of mechanical function due to corrosion, distortion, dirt, and overload; fatigue due to vibratory and cyclic thermal loads	Structures Monitoring Program	No	Structures Monitoring Program	Consistent with the GALL Report
Groups B1.1, B1.2, and B1.3: support members: welds, bolted connections, and support anchorage to building structure (3.5.1.53)	Loss of material due to general and pitting corrosion	ISI (IWF)	No	ASME Section XI, Subsection IWF Program	Consistent with the GALL Report
Groups B1.1, B1.2, and B1.3: constant and variable load spring hangers, guides, and stops (3.5.1.54)	Loss of mechanical function due to corrosion, distortion, dirt, and overload; fatigue due to vibratory and cyclic thermal loads	ISI (IWF)	No	ASME Section XI, Subsection IWF Program	Consistent with the 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 Program	No	Boric Acid Corrosion 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
Groups B1.1, B1.2, and B1.3: sliding surfaces (3.5.1.56)	Loss of mechanical function due to corrosion, distortion, dirt, and overload; fatigue due to vibratory and cyclic thermal loads	ISI (IWF)	No	ASME Section XI, Subsection IWF Program	Consistent with the GALL Report
Groups B1.1, B1.2, and B1.3: vibration isolation elements (3.5.1.57)	Reduction or loss of isolation function radiation hardening, temperature, humidity, and sustained vibratory loading	ISI (IWF)	No	Not applicable to STP	Not applicable; no in-scope vibration isolation elements for license renewal
Galvanized steel and aluminum support members, welds, bolted connections, and support anchorage to building structure exposed to air-indoor uncontrolled (3.5.1.58)	None	None	NA—No AEM or AMP	None	Consistent with the GALL Report
Stainless steel support members, welds, bolted connections, and support anchorage to building structure (3.5.1.59)	None	None	No	None	Consistent with the GALL Report (see SER Section 3.5.2.1.4)

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. 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. 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 AMR Results That Are Consistent with the GALL Report

LRA Section 3.5.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the containment, structures, and component supports and commodity groups:

- 10 CFR Part 50, Appendix J
- ASME Section XI, Subsection IWE
- ASME Section XI, Subsection IWF

- ASME Section XI, Subsection IWL
- Bolting Integrity
- Boric Acid Corrosion
- External Surfaces Monitoring
- Fire Protection
- Fire Water Systems
- Masonry Wall Program
- Periodic Surveillance and Preventive Maintenance
- RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants
- Structures Monitoring Program
- Water Chemistry

Although not identified directly in LRA Section 3.5.2.1, LRA Table 3.5.1 also identifies the TLAA under the discussion column that manages aging effects for the structures and structural components and their commodity groups for specified conditions.

LRA Tables 3.5.2-1 through 3.5.2-11 summarize AMRs for the structures and component supports 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 it does not recommend further evaluation, the staff performed an audit and review to determine whether 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 through 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 confirm the 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 GALL Report AMP. The staff reviewed these items to confirm 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 the GALL Report component, 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 a different component in the GALL Report with the same material, environment, aging effect, and AMP as the component under review. The staff reviewed these items to confirm 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 the GALL Report component, 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 confirm 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 confirm 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 confirm that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs.

The staff reviewed the LRA to confirm that the applicant provided a brief description of the system, components, materials, and environments; stated that the applicable aging effects were reviewed and evaluated in the GALL Report; and identified those aging effects for the structures and structural components and their commodity groups that are subject to an AMR. On the basis of its audit and review, the staff determines that, for AMRs not requiring further evaluation, as identified in LRA Table 3.5.1, the applicant's references to the GALL Report are acceptable, and no further staff review is required, with the exception of the AMRs that the applicant had identified were consistent with the AMRs of the GALL Report and for which the staff determined additional clarification and assessment were needed. The staff's evaluations of these AMRs are provided in the subsections that follow.

3.5.2.1.1 AMR Results Identified as Not Applicable

In Table 3.5.1, for items 3.5.1.5, 3.5.1.8, 3.5.1.11, 3.5.1.13, 3.5.1.19, 3.5.1.21, and 3.5.1.49, the applicant stated that the corresponding AMR items in the GALL Report are not applicable because STP is a PWR reactor design, and the AMR items in the GALL Report are only applicable to particular components of BWR designs. The staff confirmed that the stated AMR items in the GALL Report are only applicable to BWR designs and are not applicable to the LRA.

For items 3.5.1.30, 3.5.1.38, 3.5.1.41, and 3.5.1.57, the applicant claimed that they were not applicable. The staff reviewed the LRA and the UFSAR and confirmed that the LRA does not have any AMR results that are applicable to these items.

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 Cracking

LRA Table 3.5.1, item 3.5.1.43, addresses Groups 1–3, 5, and 6 concrete block masonry walls exposed to plant indoor air environment (LRA defined, GALL Report equivalent: air-indoor uncontrolled or air-outdoor environment), which will be managed for cracking due to restraint shrinkage, creep, and aggressive environments. For the AMR item that cites generic note E with a plant-specific note 1, the LRA credits the Masonry Wall Program and Fire Protection Program to manage the aging effect for concrete block and masonry walls used as barriers (including fire), shelters, and structural support. The GALL Report recommends GALL Report AMP XI.S5, "Masonry Wall Program," to ensure that this aging effect is adequately managed. The LRA plant-specific note 1 states that the GALL Report does not provide a line in which concrete masonry is inspected per the Fire Protection Program.

GALL Report AMP XI.S5, in conjunction with GALL Report AMP XI.S6, recommends using visual examination of the masonry walls by qualified inspection personnel to detect cracking of the masonry and degradation of steel edge supports and bracing, at a recommended frequency of 5 years to ensure that there is no loss of intended function between inspections to manage aging. The staff noted that the applicant's Masonry Wall Program, as amended, proposes to manage the aging of the concrete block masonry walls through visual examination by qualified inspection personnel for cracking of the masonry and, through its integration with the Structures Monitoring Program, the degradation of steel edge supports and bracing at a frequency to ensure that there is no loss of intended functions between inspections. The staff also noted that LRA Appendix B, Section B2.1.12, states that the Fire Protection Program will be used to manage aging of concrete block masonry walls that provide a fire barrier function through visual inspections at a frequency of once every 18 months to ensure timely detection of concrete cracking, spalling, and loss of material.

The staff's evaluations of the applicant's Structures Monitoring Program, Masonry Wall Program, and Fire Protection Program are documented in SER Sections 3.0.3.2.26, 3.0.3.2.29, and 3.0.3.2.9, respectively. In its review of components associated with item 3.5.1.43, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the as amended Masonry Wall Program integrated with its Structures Monitoring Program acceptable because the two programs are consistent with GALL Report AMPs XI.S6 and XI.S5, respectively. Furthermore, the Fire Protection Program also performs visual examinations of fire barriers, walls, ceilings, and floors at 18-month intervals for indications of cracking, spalling, and loss of material.

3.5.2.1.3 Loss of Material

LRA Table 3.5.1, item 3.5.1.47, addresses Group 6: metal structural members (e.g., carbon steel doors, barriers-fire/flood/missile, penetrations-mechanical/electrical, and cooling water structural supports) exposed to atmosphere and weather, plant indoor air, or submerged environments (LRA defined, GALL Report equivalents: air-indoor uncontrolled or air-outdoor; water-flowing or water-standing environments), which will be managed for loss of material due to general (steel only), pitting, and crevice corrosion. For the AMR item that cites generic note E with a plant-specific note 1, the LRA credits the Structures Monitoring Program to manage the aging effect of stainless steel and carbon steel structural supports, penetrations, barriers, and doors. 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. LRA plant-specific note 1 states that the GALL Report, item III.A6-11, specifies RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants as the program for metal components in water-control structures. RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.33) does not address metal components, so the Structures Monitoring Program (B2.1.32) is used.

GALL Report AMP XI.S7 recommends monitoring and inspection of dams, slopes, canals, and other raw water-control structures associated with essential cooling water systems or flood protection at intervals not to exceed 5 years by qualified engineers for loss of material, cracking, movements (e.g., settlement, heaving, deflection), conditions at junctions with abutments and embankments, erosion, cavitation, seepage, and leakage to manage aging. The staff noted that the applicant's Structures Monitoring Program, when enhanced, proposes to manage the aging of carbon steel doors, barriers (fire, flood, missile), penetrations (mechanical, electrical), and cooling water structural supports through condition monitoring, using guidelines and walkdown checklists. Furthermore, LRA Section B2.1.32 states that the Structures Monitoring Program is committed to RG 1.127, and its scope includes water-control structures that will be inspected at intervals not to exceed 5 years.

The staff's evaluations of the applicant's Structures Monitoring Program and RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program are documented in SER Sections 3.0.3.2.26 and 3.0.3.2.27, respectively. In its review of components associated with item 3.5.1.47, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging effects of the Group 6 metal structural members using the augmented Structures Monitoring Program with the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program (which is identified as the appropriate AMP in the GALL Report for this AERM) acceptable because the combined programs are consistent with the recommendations of both GALL Report AMPs XIS6 and XI.S7. Additionally, the programs implement the requirements of 10 CFR 50.65 and include inspection and surveillance activities for water-control structures on a frequency of at least once every 5 years.

LRA Table 3.5.1, item 3.5.1.50, addresses Groups B2 and B4: galvanized steel, aluminum, stainless steel support members; welds; bolted connections support anchorage to building structure exposed to atmosphere and weather (LRA defined, GALL Report equivalent: air-outdoor environment), which will be managed for loss of material due to pitting and crevice corrosion. For the AMR items that cite generic note E and plant-specific note 1, the LRA credits the ASME Section XI, Subsection IWF Program to manage the aging effect of stainless steel ASME Code Class 2 and 3 pipe supports. The GALL Report recommends GALL Report AMP XI.S6, "Structures Monitoring Program," to ensure that this aging effect is adequately managed. The plant-specific note 1 states that the GALL Report does not provide a line to evaluate stainless steel components outdoors under the ASME Section XI, Subsection IWF Program (B2.1.29).

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 the loss of intended functions and the extent of degradation will be detected. Inspection methods, inspection schedule, and inspector qualifications are to be commensurate with industry codes, standards, and guidelines. The staff noted that the applicant's ASME Section XI, Subsection IWF Program proposes to manage the aging of stainless steel supports (ASME Code Class 2 and 3) through periodic examinations in accordance with Inspection Program B of ASME Section XI, Subsection IWF. Instructions and acceptance criteria for the inspections are included in the applicant's plant procedures.

The staff's evaluation of the applicant's ASME Section XI, Subsection IWF Program is documented in SER Section 3.0.3.2.24. In its review of components associated with item 3.5.1.50, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging through periodic inspections in accordance with guidance and acceptance criteria contained in the ASME Section XI, Subsection IWF acceptable because the IWF Program implements the visual inspection requirements of ASME Code Class 1, 2, and 3 piping and supports for cracking, loss of material, and loss of mechanical function at a frequency that exceeds the requirements in the recommended GALL Report AMP.

The staff concludes that for LRA items 3.5.1.43, 3.5.1-47, and 3.5.1.50, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.1.4 Stainless Steel Support Members, Welds, Bolted Connections, and Support Anchorage to Building Structures with no AERM

LRA Table 3.5.1, item 3.5.1.59, addresses stainless steel support members, welds, bolted connections, and support anchorage to building structures and states that there is no AERM and no AMP is proposed. The LRA references item 3.5.1.59 for ASME Code Class 1, 2, and 3 supports exposed to borated water leakage or plant indoor air in LRA Table 3.5.2-11. The staff noted that ASME Code Section XI has inservice inspection requirements for ASME Code Class 1, 2, and 3 supports. The staff also noted that GALL Report AMP XI.S3, "ASME Section XI, Subsection IWF," covers the inspection criteria for ASME Code Class 1, 2, and 3 component supports for license renewal and recommends visual inspection of a sample of supports. It was not clear to the staff why the stainless steel ASME Code Class 1, 2, and 3 supports in LRA Table 3.5.2-11 have no AERM and no AMP proposed, since these supports are within the scope of components that should be inspected in accordance ASME Code Section XI, Subsection IWF. By letter dated September 22, 2011, the staff issued RAI 3.5.1.59-1 requesting that the applicant identify whether there are any ASME Code Class 1, 2, or 3 supports within the scope of license renewal that are not included in the ASME Code Section XI, Subsection IWF Program and provide justification for the supports not being managed by the program; or alternatively, provide an appropriate program to manage the aging effects.

In its response dated December 15, 2011, the applicant stated that all ASME Code Class 1, 2, and 3 supports are within the scope of license renewal and are included in the ASME Code Section XI, Subsection IWF Program. The applicant also stated that a single support may be represented by several AMR items in LRA Table 3.5.2-11 if it is constructed of more than one material in order to address each material-environment combination. The applicant further stated that while part of a support may be constructed of a material that does not require aging management based on environment, the support is still within the scope of the ASME Code Section XI, Subsection IWF Program and will be inspected in accordance with applicable IWF Program requirements.

The staff finds the applicant's response acceptable because all ASME Code Class 1, 2, and 3 supports are within the scope of license renewal and are included in the applicant's ASME Code Section XI, Subsection IWF Program, as recommended in the GALL Report. The staff's concern described in RAI 3.5.1.59-1 is resolved.

3.5.2.1.5 Cracking Due to Stress Corrosion Cracking and Loss of Material Due to Pitting and Crevice Corrosion

LRA Table 3.5.1, item 3.5.1.46, addresses stainless steel fuel pool liners exposed to treated water or treated borated water, which will be managed for cracking due to SCC and loss of material due to pitting and crevice corrosion. For the AMR items that cite item 3.5.1.46, the LRA credits the Water Chemistry Program, monitoring of the spent fuel pool water level and monitoring leakage from the leak chase channels to manage cracking due to SCC. These AMR items do not include loss of material due to pitting and crevice corrosion as an aging effect being managed. The GALL Report recommends GALL Report AMP XI.M2, “Water Chemistry,” monitoring of the spent fuel pool water level, and monitoring leakage from the leak chase channels to ensure that these aging effects are adequately managed.

The staff noted that, although loss of material is not included as an aging effect in the AMR items that cite 3.5.1.46, this aging effect is, in practice, being managed in a manner consistent with the GALL Report recommendation. This is because the aging management activities for cracking due to SCC—which is being managed for the subject components—are identical to those for loss of material.

The staff’s evaluation of the applicant’s Water Chemistry Program is documented in SER Section 3.0.3.2.1. Based on its review of components associated with item 3.5.1.46, the staff finds the applicant’s proposal to manage aging using the Water Chemistry Program and monitoring of both spent fuel pool water level and leakage from the leak chase channels acceptable because the Water Chemistry Program establishes the plant water chemistry control parameters and their limits to mitigate aging, and monitoring of water level and leak chase channels is capable of detecting fuel pool leaks prior to loss of intended function.

The staff concludes that for LRA item 3.5.1.46, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.1.6 Cracking Due to Stress Corrosion Cracking and Loss of Material Due to General Corrosion

LRA Table 3.5.1, item 3.5.1.51, addresses Group B1.1 high-strength, low-alloy bolting exposed to plant indoor air (structural) (external), which will be managed for cracking due to SCC and loss of material due to general corrosion. During its review of components associated with item 3.5.1.51, for which the applicant cited generic note B, the staff noted that the high-strength, low-alloy steel bolting components were not managed for loss of preload, as recommended by the GALL Report Revision 2, Table 3.5-1, item 87. By letter dated September 22, 2011, the staff issued RAI 3.5.2.11-1 requesting that the applicant either provide clarification as to why loss of preload is not a managed aging effect for these components or update the LRA to show that loss of preload is being managed for these components.

In its response dated November 21, 2011, the applicant stated that LRA Section 3.5.2.1.11 and Table 3.5.2-11 have been revised to add an AMR item for managing high-strength structural bolting for the aging effect of loss of preload using the ASME Section XI, Subsection IWF Program. In its response, the applicant cited generic note H because the GALL Report, Revision 1, does not address this aging effect for the component and material combination.

The staff finds the applicant’s response acceptable because the applicant revised the LRA to add this aging effect and is using the GALL Report recommended program, AMP XI.S3, “ASME Section XI, Subsection IWF,” to manage the aging. The staff’s concern described in RAI 3.5.2.11-1 is resolved.

The staff concludes that for LRA Table 3.5-1, item 3.5.1.51, the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

In LRA Section 3.5.2.2, the applicant provided further evaluations of aging management, as recommended by the GALL Report, for the containments, structures, and component supports and provided information concerning how it will manage aging effects in the following three areas:

(1) PWR containments:

- aging of inaccessible concrete areas
- cracks and distortion due to increased stress levels from settlement and reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations, if not covered by the Structures Monitoring Program
- reduction of strength and modulus of concrete structures due to elevated temperature
- loss of material due to general, pitting, and crevice corrosion
- loss of prestress due to relaxation, shrinkage, creep, and elevated temperature
- cumulative fatigue damage
- cracking due to SCC
- cracking due to cyclic loading
- loss of material (scaling, cracking, and spalling) due to freeze-thaw
- cracking due to expansion and reaction with aggregate and increase in porosity and permeability due to leaching of calcium hydroxide

(2) Safety-related and other structures and component supports:

- aging of structures not covered by the Structures Monitoring Program
- aging management of inaccessible areas (below-grade inaccessible concrete areas of Groups 1–5, and 7–9 structures)
- reduction of strength and modulus of concrete structures due to elevated temperature for Group 1–5 structures
- aging management of inaccessible areas for Group 6 structures (below-grade inaccessible concrete areas)
- cracking due to SCC and loss of material due to pitting and crevice corrosion for 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

(3) QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the report and for which the report recommends further evaluation, the staff reviewed the applicant's evaluation to determine whether it adequately addressed the issues further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.5.2.2. The staff's review of the applicant's further evaluations follows.

3.5.2.2.1 Pressurized Water Reactor Containment

The staff reviewed LRA Section 3.5.2.2.1 against the criteria in SRP-LR Section 3.5.2.2.1, which address several areas.

Item 1—Aging of Inaccessible Concrete Areas. LRA Section 3.5.2.2.1.1, associated with LRA Table 3.5.1, item 3.5.1.1, addresses inaccessible concrete elements: walls, dome, basemat, ring girder, buttresses, containment (as applicable) areas exposed to atmosphere and weather or buried environments (LRA defined, GALL Report equivalent: air-indoor uncontrolled or air-outdoor, groundwater and soil environments), which will be managed for aggressive chemical attack and corrosion of embedded steel by the ASME Section XI, Subsection IWL Program. The criteria in SRP-LR Section 3.5.2.2.1, item 1, state 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 SRP-LR also states that the existing program relies on ASME Code Section XI, Subsection IWL, to manage these aging effects; however, a plant-specific program is recommended to manage the 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 reinforced concrete structures were designed, constructed, and inspected in accordance with ACI and ASTM standards that provide for a good quality, dense, well-cured, and low permeability concrete; crack control was achieved through proper sizing, spacing, and distribution of reinforcing steel in accordance with the Proposed ACI 359, "Concrete Containments for Nuclear Reactors–Joint ACI-ASME"—ASME Code Section III, Division 2; and the ASME Section XI, Subsection IWL Program will be used as the AMP. The applicant also stated that the groundwater chemistry is monitored, and opportunistic inspections are performed whenever inaccessible concrete is exposed.

The staff's evaluation of the applicant's ASME Section XI, Subsection IWL Program is documented in SER Section 3.0.3.2.23. 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 Section XI, Subsection IWL Program. The staff also noted that the below-grade environment will continue to be monitored for aggressiveness during the period of extended operation. The staff also reviewed the UFSAR and confirmed that its Section 3.8.1.5.4 discusses concrete crack control to be in accordance with the proposed ACI 359—ASME Code Section III, Division 2. In its review of components associated with item 3.5.1.1, the staff finds that the applicant met the further evaluation criteria, and the applicant's proposal to manage aging using the ASME Section XI, Subsection IWL Program is acceptable because this is the SRP-LR recommended AMP for accessible areas, and the applicant will continue monitoring the below-grade environment for aggressiveness.

Based on the program identified, the staff determines that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.5.2.2.1, item 1. For those items that apply to LRA Section 3.5.2.2.1.1, 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).

<u>Item 2—Cracks and Distortion Due to Increased Stress Levels from Settlement and Reduction of Foundation Strength, Cracking, and Differential Settlement Due to Erosion of Porous Concrete Subfoundations, if Not Covered by the Structures Monitoring Program</u>. LRA Section 3.5.2.2.1.2, associated with LRA Table 3.5.1, item 3.5.1.2, addresses concrete components and elements exposed to atmosphere and weather and buried environments (LRA defined, GALL Report equivalent: soil), and item 3.5.1.3 addresses concrete components and elements exposed to flowing water environment. The LRA states that the aging effects for these items to be managed by the Structures Monitoring Program include 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. The criteria in SRP-LR Section 3.5.2.2.1, items 2 and 3, state 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 SRP-LR also states that the existing program relies on 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 the containment building foundation is a conventionally reinforced mat, circular in plan, of uniform thickness, and founded on structural backfill that was compacted above a dense granular layer. The applicant also stated that all ground movements have been found to correlate well with predicted values and differential and total settlements have been acceptably small; therefore, a dewatering system is not required, no porous foundations exist, and no further evaluation for this item is required. The applicant further stated that the Structures Monitoring Program monitors settlement for all major structures.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.26. The staff noted that structures and structural components and elements are monitored under the applicant's Structures Monitoring Program for aging effects related to settlement. The staff also reviewed the UFSAR and noted that the applicant does not have porous concrete subfoundations or an active dewatering system. In its review of components associated with items 3.5.1.2 and 3.5.1.3, the staff finds the applicant meets the further evaluation criteria, and the applicant's proposal to manage aging using the Structures Monitoring Program is acceptable because this is the SRP-LR recommended program, and all necessary components are within the program's scope.

Based on the program identified, the staff determines that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.5.2.2.1, item 2. For those items that apply to LRA Sections 3.5.2.2.1.2, 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).

<u>Item 3—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 concrete structures exposed to either an air-indoor or air-outdoor environment, which

will be managed for reduction of strength and modulus of elasticity due to elevated temperature exposure by limiting the concrete temperature to acceptable levels, as defined in ASME Code Section III, Division 2. The criteria in SRP-LR Section 3.5.2.2.1, item 3, state that reduction in strength and modulus of concrete structures can occur due to temperatures in excess of those specified in Subsection CC-3400 of ASME Code Section III, Division 2, for general areas (approximately 66 °C (150 °F)) and local areas (approximately 93 °C (200 °F)). The applicant addressed the further evaluation criteria of the SRP-LR by stating that this item is not applicable because concrete associated with the containment is not exposed to temperatures above these limits. The applicant also stated that, if required, insulation or cooling or both are provided to limit the concrete temperatures to acceptable levels.

The staff reviewed the UFSAR and confirmed that no in-scope containment concrete is exposed to temperatures exceeding the SRP-LR limits. The staff also reviewed the STP TS and confirmed that the limiting condition for operation (LCO) for the containment air temperature is approximately 43 °C (110 °F). In its review of components associated with item 3.5.1.4, the staff finds the applicant statement of not applicable acceptable because concrete containment and its components are subjected to temperatures below the limits provided in ACI 359-ASME Code Section III, Division 2.

Based on the program identified, the staff determines that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.5.2.2.1, item 3. For those items associated with LRA Section 3.5.2.2.1.3, 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).

Item 4—Loss of Material Due to General, Pitting, and Crevice Corrosion. LRA Section 3.5.2.2.1.4, associated with LRA Table 3.5.1, item 3.5.1.6, addresses steel elements (i.e., liner, liner anchors, and integral attachments) of accessible and inaccessible areas of containments exposed to an plant indoor air environment (LRA defined, GALL Report equivalent: air-indoor uncontrolled environment), which will be managed for loss of material due to general, pitting, and crevice corrosion by the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J, programs. The criteria in SRP-LR Section 3.5.2.2.1, item 4, state 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 SRP-LR also states that the existing program relies on ASME Code Section XI, Subsection IWE and 10 CFR Part 50, Appendix J, to manage this aging effect and that further evaluation of the plant-specific program to manage this aging effect is recommended 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:

(a) 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.

(b) 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.

(c) 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.

(d) Borated water spills and water ponding on the containment concrete floor is not common and, when detected, is cleaned up in a timely manner.

The applicant addressed the further evaluation criteria by stating that the ASME Section XI, Subsection IWE Program, in general, is used for aging management of the containment building steel liner, with inspections performed to identify and manage containment liner aging effects (i.e., cracking, loss of material, loss of sealing, and leakage) that could result in a loss of intended function. The applicant also stated that aging effects of pressure-retaining containment seals and gaskets are managed by the 10 CFR Part 50, Appendix J, Program. The applicant further stated that surface, volumetric, and visual examinations (VT-3 and VT-1) are the primary inspection methods to identify indications of degradation with ultrasonic thickness measurements performed as required. The applicant also stated that the reinforced concrete structures were designed, constructed, and inspected in accordance with ACI and ASTM standards that provide for a good quality, dense, well-cured, and low permeability concrete; concrete mixes were designed in accordance with ACI 211.1-70; procedural controls ensure that borated water spills are not common and, when detected, are cleaned up in a timely manner; and ASME Code Section XI, Subsection IWL, identifies and manages any cracks in the concrete that could potentially provide a pathway for water to reach inaccessible portions of the containment steel liner. The applicant finally stated that because of these mitigating measures, further evaluation for corrosion in inaccessible areas of the steel containment liner is not required.

The staff's evaluations of the applicant's ASME Section XI, Subsection IWE Program, the 10 CFR Part 50, Appendix J, Program, and the ASME Section XI, Subsection IWL Program are documented in SER Sections 3.0.3.2.22, 3.0.3.2.25, and 3.0.3.2.23, respectively. The staff reviewed UFSAR 3.8.3, "Concrete and Structural Steel Internal Structures of Concrete Containment," Subsection 3.8.3.2, "Applicable Codes, Standards and Specifications," and noted that the reinforced concrete structures exposed to an air-indoor uncontrolled environment were designed, constructed, and inspected in accordance with ACI and ASTM standards that provide for a good quality, dense, well-cured, and low permeability concrete. The staff also reviewed UFSAR Section 3.8.1, "Concrete Containment," Subsection 3.8.1.6.1.2, "Concrete Mixes: Selection of Concrete Mix Proportions," for the containment concrete and confirmed that concrete mixes were designed in accordance with ACI 211.1-70. The staff further noted that the UFSAR describes measures to mitigate borated water spills. In its review of components associated with item 3.5.1.6, the staff finds that the applicant's proposal to manage aging using the ASME Section XI, Subsection IWE Program, the 10 CFR Part 50, Appendix J, Program, and the ASME Section XI, Subsection IWL Program has met the further evaluation criteria associated with conditions (b), (c), and (d) identified above, but the applicant did not discuss condition (a) adequately in that it was not specified how the containment concrete in contact with the embedded containment liner meets the specifications of ACI 318 or ACI 349 and the guidance of ACI 201.2R. By letter dated September 22, 2011, the staff issued RAI 3.5.2.2.1-1 requesting that the applicant justify that the concrete adjacent to the containment liner was constructed meeting the specifications of ACI 318 or ACI 349 and the guidance of ACI 201.2R.

In its response dated November 21, 2011, the applicant stated that concrete structures other than the containment building are designed in accordance with ACI 318. The code used in the design of the containment is ASME-ACI 359, which is a standard produced by a joint committee combining input from ACI Committee 349 and the ASME Code Boiler and Pressure Vessel Code Committee. The applicant also stated that the UFSAR referenced ACI 211.1, which references ACI 201.2R, which describes concrete deterioration, mechanisms involved, and potential aging effects. The applicant also stated that ACI 211.1 provides recommendations for the specifics of designing concrete mixes for placeability, strength, and durability. The applicant further stated that since the requirements of ACI 201.2R are incorporated into ACI 211.1 by reference, the applicable requirements are addressed in the concrete designs.

The staff finds the applicant's response acceptable because the requirements of ACI 201.2R are incorporated into ACI 211.1 by reference; hence, it satisfies the acceptance criteria in SRP-LR Section 3.5.2.2.1. The applicant's AMR, therefore, is consistent with the GALL Report, item II.A1-11. The staff's concern described in RAI 3.5.2.2.1-1 is resolved.

During its review of components associated with item 3.5.1.6, the staff finds the applicant's proposal to manage aging using ASME Section XI, Subsection IWE Program, the 10 CFR Part 50, Appendix J, Program, and the ASME Section XI, Subsection IWL Program is acceptable because the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J, programs are the recommended programs to manage loss of material due to corrosion of steel elements: steel liner, liner anchors, and integral attachments in an air-indoor, uncontrolled environment. Additionally, the applicant demonstrated that the loss of material due to corrosion is insignificant when the GALL Report recommendations for item II.A1-11 are satisfied, and the applicant uses an additional AMP—its ASME Section XI, Subsection IWL Program—to further identify, evaluate, and manage any evidenced cracks in the concrete that could cause moisture to infiltrate initiating conditions for potential corrosion to the liner.

Based on the programs identified, the staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.5.2.2.1, item 4. For those items that apply to LRA Section 3.5.2.2.1.4, 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).

<u>Item 5—Loss of Prestress Due to Relaxation, Shrinkage, Creep, and Elevated Temperature</u>. LRA Section 3.5.2.2.1.5, associated with LRA Table 3.5.1, item 3.5.1.7, addresses prestressed containment steel tendons exposed to atmosphere and weather environment (LRA defined, GALL Report equivalent: air-indoor uncontrolled or air-outdoor environment), which will be managed for loss of prestress due to relaxation, shrinkage, creep, and elevated temperature by a TLAA. The criteria in SRP-LR Section 3.5.2.2.1, item 5, state that loss of prestress due to relaxation, shrinkage, creep, and elevated temperature is a TLAA, as defined in 10 CFR 54.3. The SRP-LR also states that TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The applicant addressed the further evaluation criteria of the SRP-LR by stating that LRA Section 4.5 describes the evaluation of this TLAA.

The staff's evaluation of the TLAA is documented in SER Section 4.5, "Concrete Containment Prestress Loss." In its review of components associated with item 3.5.1.7, the staff finds that the applicant meets the further evaluation criteria, and the applicant's proposal to manage aging using the TLAA is acceptable because this is the SRP-LR recommended program, and all necessary components are within the program's scope.

Based on the program identified, the staff determines that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.5.2.2.1, item 5. For those items that apply to LRA Section 3.5.2.2.1.5, 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).

Item 6—Cumulative Fatigue Damage. LRA Section 3.5.2.2.1.6, associated with LRA Table 3.5.1, item 9, addresses steel, stainless steel elements: suppression pool steel shells (including welded joints) and penetrations (including penetration sleeves, dissimilar metal welds, and penetration bellows), and downcomers exposed to plant indoor air environment (LRA defined, GALL Report equivalent: air-indoor uncontrolled or air-outdoor environment), which will be managed for cracking due to fatigue by a TLAA, as defined in 10 CFR 54.3. The criteria in SRP-LR Section 3.5.2.2.1, item 6, state that the TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The applicant addressed the further evaluation criteria by stating that the TLAAs are evaluated in accordance with10 CFR 54.21(c) criteria, are included in LRA Section 4.6, and address containment penetrations for the main steam, feedwater, AFW, and SG blowdown penetrations, as well as the fuel transfer tube bellows. The applicant also stated that a review of design documentation indicates that neither a fatigue analysis nor design for a stated number of cycles exists for the liner plate; therefore, the liner plate is not a TLAA, as defined by 10 CFR 54.3(a) Criterion 6.

The staff's evaluation of the TLAAs is documented in SER Section 4. The staff confirmed that fatigue of containment penetrations is addressed and that a TLAA of the liner plate is not required. In its review of components associated with item 3.5.1.9, the staff finds the applicant met the further evaluation criteria because the required review to identify TLAAs has been completed.

Based on the programs identified, the staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.5.2.2.1, item 6. For those items that apply to LRA Section 3.5.2.2.1.6, 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).

Item 7—Cracking Due to Stress-Corrosion Cracking. LRA Section 3.5.2.2.1.7 states that for LRA Table 3.5.1, item 3.5.1.10, cracking due to SCC is not an AERM for STP stainless steel containment penetration sleeves, bellows, and dissimilar metal welds. The applicant also stated that both high temperature (greater than approximately 43 °C (140 °F)) and exposure to an aggressive environment are required for SCC to be applicable, and at STP, these two conditions are not simultaneously present for any stainless steel penetration sleeves, bellows, or dissimilar metal welds. The applicant further stated that review of STP plant-specific operating experience did not identify any SCC of these components.

In its review related to this item, the staff noted that LRA Table 3.5.2-1 for containments, structures, and component supports indicates that stainless steel containment penetrations and bellows are exposed to plant indoor air and are subject to cracking due to SCC, consistent with the GALL Report, Volume 2, item II.A3-2, and that this aging effect is managed by the applicant's ASME Section XI, Subsection IWE Program and 10 CFR Part 50, Appendix J, Program. The staff also noted that LRA Table 3.5-1, item 3.5.1.10, addresses the AMR results, consistent with those described in LRA Table 3.5.2-1, which indicate that cracking due to SCC of the stainless steel containment penetration components is managed by the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J, programs.

Therefore, the staff noted that the applicant's AMR results described in LRA Tables 3.5-1 and 3.5.2-1 are in conflict with the applicant's claim described in LRA Section 3.5.2.2.1.7, that cracking due to SCC is not applicable for the stainless steel containment penetration components (sleeves, bellows, and dissimilar metal welds). During the AMP audit, the staff also noted that the applicant has operating experience with groundwater in-leakage and accumulation in the area between the fuel handling building and the containment building of both units; however, the staff further noted that the LRA does not provide the applicant's operating experience regarding potential exposure of the penetration components to groundwater in-leakage and accumulation. Therefore, the staff needed clarification concerning the apparent conflict in the AMR results and additional information regarding the operating experience of groundwater in-leakage.

By letter dated September 22, 2011, the staff issued RAI 3.5.2.2.1.7-1 requesting that the applicant describe the plant-specific operating experience of groundwater in-leakage and accumulation to clarify whether the containment penetration components have been exposed to groundwater. The staff also requested that if the containment penetration components have been exposed to groundwater leakage, the applicant should justify why the exposure of the components to groundwater is not conducive to SCC of the stainless steel components, taking into account the potential for the contamination of the leaked groundwater to contain corrosive species (such as chlorides). The staff also requested that if cracking due to SCC is not applicable to the containment penetration components, the applicant should describe how it will evaluate future operating experience to identify and perform any necessary corrective actions to ensure that the intended functions of these components are maintained. In addition, the applicant was asked to provide a technical basis for its determination on the applicability of SCC to the containment penetration components. The staff requested that if cracking due to SCC is applicable to the containment penetration components, the applicant should justify why the use of the ASME Section XI, Subsection IWE and the 10 CFR Part 50, Appendix J, programs, without the additional augmented inspection recommended in the GALL Report, are adequate to detect and manage the aging effect. The staff further asked the applicant to resolve the conflict between the AMR results described in LRA Section 3.5.2.2.1.7, Table 3.5-1, and Table 3.5.2-1 to clarify whether cracking due to SCC is applicable to the stainless steel penetration components.

In its response dated November 21, 2011, the applicant stated that the groundwater in-leakage between the fuel handling building and the containment building is in an area with a floor elevation of - 29 ft and has accumulated to a depth of 6 or 7 ft. The applicant also indicated that since the lowest containment penetration is in the emergency sump at an elevation of - 15 ft 3 in, no containment penetrations have been exposed to this groundwater. The applicant further indicated that cracking due to SCC is not an aging effect that is expected to occur for the applicant's stainless steel containment penetration sleeves, bellows, and dissimilar metal welds because the normal operating temperature inside the containment building is limited to approximately 49 °C (120 °F), as specified in UFSAR Table 9.4-1, which is below the threshold temperature of approximately 60 °C (140 °F) for SCC, as addressed in the GALL Report. In addition, the applicant indicated that the environment inside the containment is non-aggressive because the sealed containment prevents contact with uncontrolled outside air, and procedural controls limit which substances may be brought into the containment. The applicant also stated that review of STP plant-specific operating experience did not identify any SCC of stainless steel containment penetration sleeves, bellows, and dissimilar metal welds. The applicant also stated that the fuel transfer tube and associated expansion bellows are part of the containment pressure boundary and, as such, these components are within the scope of license renewal under the ASME Section XI, Subsection IWE Program and the 10 CFR Part 50, Appendix J, Program. The applicant also indicated that, as discussed above, SCC is not expected to occur under the conditions present at STP, but these AMPs will continue to monitor the containment penetration components in order to confirm the absence of cracking due to SCC. In its response, the applicant further stated that plant-specific and industry operating experience is continuously reviewed to confirm the effectiveness of AMPs and is used, as necessary, to enhance each AMP or to develop new AMPs in order to adequately manage the effects of aging so that the intended functions of SCs are met. In addition, the applicant indicated that any plant-specific condition that is found to be outside of the applicable acceptance criteria is evaluated in the CAP. The applicant provided the revision to LRA Section 3.5.2.1.1 and Table 3.5.2-1 to include the dissimilar metal welds in its AMRs for the containment penetration components.

In its review, the staff finds that the applicant's response is acceptable because the applicant confirmed the following:

- The containment penetration components have not been exposed to the groundwater.
- The normal operating temperature inside the containment building is limited to approximately 48 °C (120 °F), which is below the threshold temperature for SCC.
- The environment is non-corrosive, as supported by the plant-specific operating experience indicating no occurrence of SCC of the containment penetration components.
- The existing ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J, programs are used to confirm no occurrence of SCC in the containment penetration components.
- Its ongoing review of plant-specific and industry operating experience is continuously performed to maintain the effectiveness of the AMPs, including corrective actions.
- The LRA is revised to include dissimilar metal welds in its AMRs, consistent with the GALL Report.

The staff's concerns in RAI 3.5.2.2.1.7-1 are resolved.

The staff evaluated the applicant's claim that the cracking due to SCC is not applicable to the components and finds it acceptable because no containment penetration component has been exposed to groundwater, and the indoor air environment with the normal operating temperature up to approximately 49 °C (120 °F) is not conducive to SCC of these components, as supported by the applicant's operating experience.

<u>Item 8—Cracking Due to Cyclic Loading</u>. LRA Section 3.5.2.2.1.8, associated with Table 3.5.1, item 12, addresses cracking due to cyclic loading of steel, stainless steel elements, and dissimilar metal welds in penetration sleeves and bellows as well as in suppression pool shell and unbraced downcomers exposed to an air-indoor uncontrolled or air-outdoor environment when CLB fatigue analysis does not exist. The applicant stated that this item is not applicable because fatigue of metal components is a TLAA and is evaluated in accordance with 10 CFR 54.21(c). The applicant also stated that the LRA does not use the applicable GALL Report items. The staff reviewed LRA Sections 2.4.1 and 3.5 for the GALL Report referenced items II.A3-3 and II.B4-3 and noted these numbers are not used in the LRA AMR Tables, and the GALL Report, Revision 2, eliminates the need for further evaluation of these items. The staff also noted item II.B4-2 is not applicable because STP is a PWR. Therefore, the applicant's AMR is consistent with the referenced GALL Report items.

<u>Item 9—Loss of Material (Scaling, Cracking, and Spalling) Due to Freeze-Thaw</u>. LRA Section 3.5.2.2.1.9, associated with LRA Table 3.5.1, item 14, addresses concrete elements: dome, wall, basemat ring girder, buttresses, containment (as applicable) exposed to buried

environment (LRA defined, GALL Report equivalent: air-outdoor environment), which will be managed for loss of material (scaling, cracking, and spalling) due to freeze-thaw by the ASME Section XI, Subsection IWL Program. The criteria in SRP-LR Section 3.5.2.2.1, item 9, state that loss of material due to freeze-thaw could occur in PWR concrete containments and recommend further evaluation of this aging effect for plants located in moderate to severe weathering conditions. The applicant addressed the further evaluation criteria of the SRP-LR by stating that STP is located in a weathering zone classified as “Negligible,” in accordance with Figure 1 of ASTM C33-07, “Standard Specification for Concrete Aggregates”; therefore, this AERM is not applicable.

The staff’s evaluation of the applicant’s ASME Section XI, Subsection IWL Program is documented in SER Section 3.0.3.2.23. The staff noted that the applicant used the GALL Report, item II.A1-2, referenced by LRA Table 3.5.1, item 3.5.1.14, for managing aging effects of dome, walls, basemat, ring girders, buttresses, containment (reinforced and prestressed, as applicable) for freeze-thaw conditions. The staff reviewed UFSAR Section 2.3.1.2, “Regional Meteorological Conditions for Design and Operating Bases,” and noted that the site area averages less than 1 day per year with glaze. The UFSAR section also states that meteorological data from nearby Victoria indicates hail occurrences are seldom (less than 0.5 percent of the total hours during the peak months February to May), with no ice storms reported within a 50-mile radius of the site from 1959 to 1972. The staff also reviewed Figure 1 of ASTM C33-99, which is the map of the U.S. weathering regions and confirmed that the weathering index and region for STP is classified as “Negligible.” In its review of components associated with item 3.5.1.14, the staff finds the applicant met the further evaluation criteria because the AMR is consistent with GALL Report referenced item II.A1-2 entry, which recommends further evaluation only for inaccessible areas of plants that are located in moderate to severe weathering conditions.

Based on the program identified, the staff determines that the applicant’s program meets the further evaluation criteria of SRP-LR Section 3.5.2.2.1, item 9. For those items that apply to LRA Section 3.5.2.2.1.9, 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).

<u>Item 10—Cracking Due to Expansion and Reaction with Aggregate, and Increase in Porosity and Permeability Due to Leaching of Calcium Hydroxide</u>. LRA Section 3.5.2.2.1.10, associated with LRA Table 3.5.1, item 3.5.1.15, addresses concrete components exposed to atmosphere and weather, buried environments (LRA defined, GALL Report equivalent: any water-flowing environments), which will be managed for cracking due to expansion and reaction with aggregate, and increase in porosity and permeability due to leaching of calcium hydroxide, by the ASME Section XI, Subsection IWL Program. The criteria in SRP-LR Section 3.5.2.2.1, item 10, state 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 PWR concrete and steel containments. The SRP-LR also states that the existing program relies on ASME Code Section XI, Subsection IWL to manage these aging effects, and further evaluation is recommended if the concrete was not constructed in accordance with the recommendations in ACI 201.2R-77. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the potential reactivity of the aggregates was evaluated in accordance with an appendix to ASTM C33-74, and it was noted that the aggregates may be potentially reactive. As a result, a low-alkali cement was used in the concrete. The applicant also stated that accessible concrete components are monitored by the ASME Section XI,

Subsection IWL Program to confirm the absence of any visible effects due to reaction with aggregate; therefore, further evaluation of the effects of reaction with aggregates is not required. The applicant further stated that the reinforced concrete structures were designed, constructed, and inspected in accordance with ACI and ASTM standards (e.g., ACI 211.1-70 for concrete mix design), which provide for a good quality, dense, well-cured, and low permeability concrete; therefore, further evaluation for the effects of leaching of calcium hydroxide is not required.

The staff's evaluation of the applicant's ASME Section XI, Subsection IWL Program is documented in SER Section 3.0.3.2.23. The staff noted that the applicant used the ASME Section XI, Subsection IWL Program to manage cracking, loss of material, and increase in porosity and permeability of the concrete containment building, evaluated the aggregate materials in accordance with ASTM standards, and used low-alkali cement to minimize the potential for alkali-aggregate reactions. The staff also noted that the applicant evaluated the aggregate material for potential reactivity through guidance in an appendix to ASTM C33 that references test methods provided in ASTM C289 and ASTM C295, and, because the results indicated that the aggregate may be potentially reactive, a low-alkali cement was used in the concrete mixtures to reduce the potential for alkali-aggregate reactions. The staff further noted that although use of low-alkali cement may not always prevent adverse reactions between the aggregate materials and cement, the applicant inspects visible surfaces through the ASME Section XI, Subsection IWL Program for signs of cracking that would indicate the occurrence of such reactions. The staff, however, noted that the applicant did not specifically discuss whether the concrete was constructed in accordance with the recommendations in ACI 201.2R-77 and, by letter dated September 22, 2011, issued RAI 3.5.2.2.1-1. The applicant's response to RAI 3.5.2.2.1-1, dated November 21, 2011, and the staff's acceptance of this issue was elaborated in SER Section 3.5.2.2 under "Loss of Material Due to General, Pitting and Crevice Corrosion," associated with LRA Table 3.5.1, item 3.5.1.6, addressing further evaluation of LRA Section 3.5.2.2.1.4.

In its review of components associated with item 3.5.1.15, the staff finds the applicant meets the further evaluation criteria for the following reasons:

- It uses the GALL Report recommended ASME Code Section XI, Subsection IWL to manage these aging effects.
- It followed the ACI and ASTM standards and recommendations, including the implementation of ACI 201.2R-77, as referenced by ACI 211.1.
- It addressed the further evaluation criteria of the SRP-LR by stating that the potential reactivity of the aggregates was evaluated in accordance with an appendix to ASTM C33-74.
- It used a low-alkali cement to mitigate potential aggregate reactivity.
- The AMR is consistent with GALL Report referenced item II.A1-2 entry, which recommends further evaluation only for inaccessible areas of plants that are located in moderate to severe weathering conditions.

Based on the program identified, the staff determines that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.5.2.2.1, item 10. For those items that apply to LRA Section 3.5.2.2.1.10, 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).

3.5.2.2.2 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 address several areas, as discussed below.

Item 1—Aging of Structures Not Covered by the 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 3.5.2.2.2.1.1, associated with LRA Table 3.5.1, item 3.5.1.23, addresses interior and above-grade exterior concrete components of Groups 1–5, 7, and 9 structures exposed to plant indoor air, atmosphere and weather environments (LRA defined, GALL Report equivalent: air-indoor uncontrolled or air-outdoor environment), which will be managed for cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel by the Structures Monitoring Program. The criteria in SRP-LR Section 3.5.2.2.2.1, item 1, state that cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel could occur in concrete components of Groups 1–5, 7, and 9 structures. The SRP-LR also states that if the aging effects for the affected structures are not managed by the Structures Monitoring Program, further evaluation is recommended. The applicant addressed the further evaluation criteria of the SRP-LR by stating 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 3.0.3.2.26. The staff noted that the components are monitored under the Structures Monitoring Program for aging effects related to cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel for Groups 1–5, 7, and 9 concrete structures. Based on its review of components associated with item 3.5.1.23, the staff finds the applicant meets the further evaluation criteria because the components are monitored under the Structures Monitoring Program, which is the GALL Report recommended program for this AERM.

Based on the program identified, the staff determines that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.5.2.2.2.1, item 1. For those items that apply to LRA Section 3.5.2.2.2.1.1, 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).

(2) Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling) due to Aggressive Chemical Attack for Groups 1–5, 7, and 9 Structures

LRA Section 3.5.2.2.2.1.2, associated with LRA Table 3.5.1, item 3.5.1.24, addresses interior and above-grade exterior concrete components of Groups 1–5, 7, and 9 structures exposed to plant indoor air, atmosphere and weather environments (LRA defined, GALL Report equivalent: air-indoor uncontrolled or air-outdoor environment), which will be managed for increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack by the Structures Monitoring Program. The criteria in SRP-LR Section 3.5.2.2.2.1, item 2, state that increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack could occur in concrete components of Groups 1–5, 7, and 9 structures. The SRP-LR also states that if the aging effects for the affected structures are not managed by the Structures Monitoring Program, further evaluation is recommended. The applicant addressed the further evaluation criteria of the SRP-LR by stating 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 3.0.3.2.26. The staff noted that the components are monitored under the Structures Monitoring Program for aging effects related to increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack for Groups 1–5, 7, and 9 concrete structures. In its review of components associated with item 3.5.1.24, the staff finds the applicant meets the further evaluation criteria because the components are monitored under the Structures Monitoring Program, which is the GALL Report recommended program for this AERM.

Based on the program identified, the staff determines that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.5.2.2.2.1, item 2. For those items that apply to LRA Section 3.5.2.2.2.1.2, 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) Loss of Material Due to Corrosion for Groups 1–5, 7, and 8 Structures

LRA Section 3.5.2.2.2.1.3, associated with LRA Table 3.5.1, item 3.5.1.25, addresses steel components of Groups 1–5, 7, and 8 structures exposed to plant indoor air, atmosphere and weather environments (LRA defined, GALL Report equivalent: air-indoor uncontrolled or air-outdoor environment), which will be managed for loss of material due to corrosion by the Structures Monitoring Program. The criteria in SRP-LR Section 3.5.2.2.2.1, item 3, state that loss of material due to corrosion could occur in steel components of Groups 1–5, 7, and 8 structures. The SRP-LR also states that if the aging effects for the affected structures are not managed by the Structures Monitoring Program, further evaluation is recommended. The applicant addressed the further evaluation criteria of the SRP-LR by stating 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 3.0.3.2.26. The staff noted that the steel components are monitored under the Structures Monitoring Program for aging effects related to loss of material due to corrosion for Groups 1–5, 7, and 8 steel structures. In its review of components associated with item 3.5.1.25, the staff finds the applicant meets the further evaluation criteria because the components are monitored under the Structures Monitoring Program, which is the GALL Report recommended program for this AERM.

Based on the program identified, the staff determines that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.5.2.2.2.1, item 3. For those items that apply to LRA Section 3.5.2.2.2.1.3, 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).

(4) Loss of Material (Spalling, Scaling) and Cracking Due to Freeze-Thaw for Groups 1–5 and 7–9 Structures

LRA Section 3.5.2.2.2.1.4, associated with LRA Table 3.5.1, item 3.5.1.26, addresses exterior above- and below-grade concrete foundations of Groups 1–5 and 7–9 structures exposed to an atmosphere and weather environment (LRA defined, GALL Report equivalent: air-outdoor environment), which will be managed for loss of material (spalling, scaling) and cracking due to freeze-thaw by the Structures Monitoring Program. The criteria in SRP-LR Section 3.5.2.2.2.1, item 4, state that loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in concrete components of Groups 1–5 and 7–9 structures. The SRP-LR also states that if the aging effects for the affected structures are not managed by the Structures Monitoring Program, further evaluation is recommended. The applicant addressed the further evaluation criteria of the SRP-LR by stating that STP is located in a weathering zone classified as "Negligible" in accordance with Figure 1 of ASTM C33-07; therefore, further evaluation for this AERM is not required.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.26. The staff noted that STP is located in a weathering zone classified as "Negligible" by ASTM C33-07. The staff reviewed UFSAR Section 2.3.1.2, "Regional Meteorological Conditions for Design and Operating Bases," and noted that the site area averages less than 1 day per year with glaze. The UFSAR also states that meteorological data from nearby Victoria indicates hail occurrences to occur seldom (less than 0.5 percent of the total hours during the peak months February to May) with no ice storms reported within a 50-mile radius of the site from 1959 to 1972. The staff also reviewed Figure 1 of ASTM C33-99, which is the map of U.S. weathering regions, and confirmed that the weathering index and region for STP is classified as "Negligible." The staff, therefore, concluded that the site is not subject to freeze-thaw actions. In its review of components associated with item 3.5.1.26, the staff finds the applicant meets the further evaluation criteria because STP is not subject to freeze-thaw actions; therefore, no further evaluation for the effects of freeze-thaw is required.

Based on the program identified, the staff determines that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.5.2.2.2.1, item 4. For those items that apply to LRA Section 3.5.2.2.2.1.4, 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).

(5) Cracking Due to Expansion and Reaction with Aggregates for Groups 1–5 and 7–9 Structures

LRA Section 3.5.2.2.2.1.5, associated with LRA Table 3.5.1, item 3.5.1.27, addresses concrete components of Groups 1–5 and 7–9 structures exposed to plant indoor air, atmosphere and weather, buried environments (LRA defined, GALL Report equivalent: any environment), which will be managed for cracking due to expansion and reaction with aggregates by the Structures Monitoring Program. The criteria in SRP-LR Section 3.5.2.2.2.1, item 5, state that cracking due to expansion and reaction with aggregates could occur in concrete elements of Groups 1–5 and 7–9 structures. The SRP-LR also states that if the aging effects for the affected structures are not managed by the Structures Monitoring Program, further evaluation is recommended. The applicant addressed the further evaluation criteria of the SRP-LR by stating 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 3.0.3.2.26. The staff noted that the components are monitored under the Structures Monitoring Program for aging effects related to cracking due to expansion and reaction with aggregates for Groups 1–5 and 7–9 concrete structures. In its review of components associated with item 3.5.1.27, the staff finds the applicant meets the further evaluation criteria because the components are monitored under the Structures Monitoring Program, which is the GALL Report recommended program for this AERM.

Based on the program identified, the staff determines that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.5.2.2.2.1, item 5. For those items that apply to LRA Section 3.5.2.2.2.1.5, 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).

(6) Cracks and Distortion Due to Increased Stress Levels from Settlement for Groups 1–3 and 5–9 Structures

LRA Section 3.5.2.2.2.1.6, associated with LRA Table 3.5.1, item 3.5.1.28, addresses concrete components of Groups 1–3 and 5–9 structures exposed to a buried environment (LRA defined, GALL Report equivalent: soil environment), which will be managed for cracks and distortion due to increased stress levels from settlement by the Structures Monitoring Program. The criteria in SRP-LR Section 3.5.2.2.2.1, item 6, state that cracks and distortion due to settlement could occur in components of Groups 1–3 and 5–9 concrete structures. The SRP-LR also states that if the aging effects for the affected structures are not managed by the Structures Monitoring Program, further evaluation is recommended. The SRP-LR further states that 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. The applicant addressed the further evaluation criteria of the SRP-LR by stating 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 3.0.3.2.26. The staff noted that the components are monitored under the Structures Monitoring Program for aging effects related to cracks and distortion due to increased stress levels from settlement for Groups 1–3 and 5–9 concrete structures. The staff also reviewed the UFSAR and noted that the UFSAR does not indicate the existence of an active dewatering system. In its review of components associated with item 3.5.1.28, the staff finds the applicant meets the further evaluation criteria because the components are monitored under the Structures Monitoring Program, which is the GALL Report recommended program for this AERM.

Based on the program identified, the staff determines that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.5.2.2.2.1, item 6. For those items that apply to LRA Section 3.5.2.2.2.1.6, 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).

(7) Reduction in Foundation Strength, Cracking, and Differential Settlement Due to Erosion of Porous Concrete Subfoundation for Groups 1–3 and 5–9 Structures

LRA Section 3.5.2.2.2.1.7, associated with LRA Table 3.5.1, item 3.5.1.29, addresses concrete components of Groups 1–3 and 5–9 structures exposed to a water flowing under foundation environment being managed for reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations by the Structures Monitoring Program. The criteria in SRP-LR Section 3.5.2.2.2.1, item 7, state that reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations could occur in components of Groups 1–3 and 5–9 concrete structures. The SRP-LR also states that if the aging effects for the affected structures are not managed by the Structures Monitoring Program, further evaluation is recommended. The SRP-LR further states that 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. The applicant addressed the further evaluation criteria of the SRP-LR by stating that that this item is covered by the Structures Monitoring Program. The applicant also stated that STP does not have porous concrete subfoundations requiring management of aging effects; hence, no further evaluation for this effect is required.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.26. The staff noted that this item is covered by the Structures Monitoring Program. The staff also reviewed the UFSAR and noted that STP does not have porous concrete subfoundations and an active dewatering system. In its review of components associated with item 3.5.1.29, the staff finds the applicant meets the further evaluation criteria because aging is managed by the Structures Monitoring Program, and STP does not have porous concrete subfoundations and an active dewatering system.

Based on the program identified, the staff determines that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.5.2.2.2.1, item 7. For those items that apply to LRA Section 3.5.2.2.2.1.7, 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).

(8) Lockup Due to Wear for Lubrite® Radial Beam Seats in BWR Drywell and Other Sliding Support Bearings and Sliding Support Surfaces

LRA Section 3.5.2.2.2.1.8, associated with LRA Table 3.5.1, item 3.5.1.30, addresses RPV support shoes for PWRs with nozzle supports, SG supports, and sliding support surfaces exposed to an air-indoor uncontrolled environment, which will be managed for lock-up due to wear in Lubrite® by the Structures Monitoring Program. The criteria in SRP-LR Section 3.5.2.2.2.1, state that lock up due to wear could occur for Lubrite® RPV support shoes for PWR nozzle supports, SG supports, and other sliding support bearings and sliding support surfaces. The SRP-LR also states that if the aging effects for the affected structures are not managed by the Structures Monitoring Program or the ASME Section XI, Subsection IWF Program, further evaluation is recommended. The applicant addressed the further evaluation criteria of the SRP-LR by stating this item is not applicable because Lubrite® was not used with respect to RPV support shoes or SG supports. The applicant also stated that where Lubrite® was used as part of a support structure, the Structures Monitoring Program or the ASME Section XI, Subsection IWF Program were used as the AMPs.

The staff's evaluations of the applicant's Structures Monitoring Program and ASME Section XI, Subsection IWF Program are documented in SER Sections 3.0.3.2.26 and 3.0.3.2.24, respectively. The staff noted that Lubrite® was not used in conjunction with the RPV support shoes or SG supports and that, where Lubrite® was used in conjunction with a support structure, the structure and aging effect combination is covered by the Structures Monitoring Program or the ASME Section XI, Subsection IWF Program. In its review of components associated with item 3.5.1.30, the staff finds the applicant meets the further evaluation criteria because all in-scope sliding surfaces are monitored under the Structures Monitoring Program or the ASME Section XI, Subsection IWF Program.

Based on the programs identified, the staff determines that the applicant's programs meet the further evaluation criteria of SRP-LR Section 3.5.2.2.2.1. For those items that apply to LRA Section 3.5.2.2.2.1.8, 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).

Item 2—Aging Management of Inaccessible Areas. 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 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 inaccessible concrete components (exterior above- and below-grade foundations) of Groups 1–3, 5, and 7–9 structures exposed to an atmosphere and weather environment (LRA defined, GALL Report equivalent: air-outdoor environment), which will be managed for loss of material (scaling, cracking, and spalling) due to freeze-thaw by the Structures Monitoring Program. The criteria in SRP-LR Section 3.5.2.2.2.2, item 1, state that loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade components of Groups 1–3, 5, and 7–9 concrete structures. The SRP-LR also states that further evaluation of this aging effect under the Structures Monitoring Program is recommended for inaccessible areas of these groups of structures for plants located in moderate to severe weathering conditions. The applicant addressed the further evaluation criteria of the SRP-LR by stating that STP is located in a weathering zone classified as "Negligible" in accordance with Figure 1 of ASTM C33-07; therefore, this AERM is not applicable.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.26. The staff noted that STP is located in a weathering zone classified as "Negligible" by ASTM C33-07. The staff reviewed UFSAR Section 2.3.1.2, "Regional Meteorological Conditions for Design and Operating Bases," and noted that the site area averages less than 1 day per year with glaze. The UFSAR also states that meteorological data from nearby Victoria indicates hail occurrences to occur seldom (less than 0.5 percent of the total hours during the peak months February to May) with no ice storms reported within a 50-mile radius of the site from 1959 to 1972. The staff also reviewed Figure 1 of ASTM C33-99, which is the map of the U.S. weathering regions and confirmed that the weathering index and region for STP is classified as "Negligible." The staff, therefore, concluded that the site is not subject to freeze-thaw actions. In its review of components associated with item 3.5.1.26 and SRP-LR Section 3.5.2.2.2.2, item 1, the staff finds the applicant meets the further evaluation criteria because STP is located in a "Negligible" weathering zone and is not subject to freeze-thaw actions; therefore, no further evaluation for the effects of freeze-thaw is required.

Based on the program identified, the staff determines that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.5.2.2.2.2, item 1. For those items that apply to LRA Section 3.5.2.2.2.2.1, 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).

(2) Cracking due to expansion and reaction with aggregates in below-grade inaccessible concrete areas for Groups 1–5 and 7–9 structures

LRA Section 3.5.2.2.2.2.2, associated with LRA Table 3.5.1, item 3.5.1.27, addresses inaccessible concrete components of Groups 1–5 and 7–9 structures exposed to a plant indoor air, atmosphere and weather, buried environments (LRA defined, GALL Report equivalent: any environment), which will be managed for cracking due to reaction with aggregates by the Structures Monitoring Program. The criteria in SRP-LR Section 3.5.2.2.2.2, item 2, state that cracking due to expansion and reaction with aggregates could occur in below-grade inaccessible areas of Groups 1–5 and 7–9 concrete structures. The SRP-LR also states that further evaluation is recommended for inaccessible areas of these groups of structures if the concrete was not constructed in accordance with recommendations in ACI 201.2R-77. GALL Report item III.A3-2 states that investigations, tests, and petrographic examinations of aggregates, performed in accordance with ASTM C295-54 or ASTM C227-50, can demonstrate that the aggregate is not reactive within the reinforced concrete. If either of these two conditions is met, the GALL Report notes that aging management is not necessary. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the aggregate was found to be potentially reactive when evaluated in accordance with an appendix to ASTM C33-74, and, as a result, a low-alkali cement was used in the concrete mixtures. The applicant also stated that accessible concrete components are monitored by the Structures Monitoring Program to confirm the absence of any visible effects due to reaction with aggregate; therefore, further evaluation of the effects of reaction with aggregates is not required.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.26. The staff noted that the applicant uses the Structures Monitoring Program to manage concrete cracking due to the reactivity of its constituent aggregates in accessible areas of these groups of structures. The staff reviewed UFSAR Section 3.8.1.6, "Material, Quality Control, and Special Construction Techniques," Subsection 3.8.1.6.1, "Concrete," and Subsection 3.8.1.6.1.1, "Materials," and also noted that the applicant evaluated the aggregate material for potential reactivity through guidance in an appendix to ASTM C33 that references test methods provided in ASTM C289 and ASTM C295 and that low-alkali cement was used in the concrete mixtures to reduce the potential for alkali-aggregate reactions. The staff further noted that although the UFSAR does not specifically discuss whether concrete was constructed in accordance with the recommendations in ACI 201.2R-77, the applicant—in its response to RAI 3.5.2.2.1-1—stated that it has applied ACI 201.2R by referencing ACI 211.1. In turn, ACI 211.1 references ACI 201.2R. In its review of components associated with item 3.5.1.27 and SRP-LR Section 3.5.2.2.2.2, item 2, the staff finds that the applicant meets the further evaluation criteria because it applied ACI 211.1 by reference, its AMR is consistent with GALL Report, which recommends further evaluation if concrete was not constructed in accordance with ACI 201.2R-77, and the accessible components are monitored under the Structures Monitoring Program. Additionally, the aggregate materials have been evaluated for potential reactivity, and low-alkali cement was used in the concrete mixtures.

Based on the evaluation provided, the staff determines that the applicant meets the further evaluation criteria of SRP-LR Section 3.5.2.2.2.2, item 2. For those items that apply to LRA Section 3.5.2.2.2.2.2, 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) Cracks and distortion due to increased stress levels from settlement and reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations in below-grade inaccessible concrete areas of Groups 1–3, 5, and 7–9 structures

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 inaccessible concrete subfoundations of Groups 1–3, 5, and 7–9 structures exposed to a buried environment (LRA defined, GALL Report equivalent: soil environment), which will be 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 3.5.2.2.2.2, item 3, state that cracks and distortion due to increased stress levels from settlement and reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations could occur in below-grade inaccessible concrete areas of Groups 1–3, 5, and 7–9 structures. The SRP-LR states that no further evaluation is recommended if this activity and these aging effects are included in the scope of the applicant's Structures Monitoring Program. If the plant relies on a dewatering system to lower the groundwater level, it is recommended that the continued functionality of the dewatering system be confirmed during the period of extended operation. The applicant addressed the further evaluation criteria of the SRP-LR by stating that that these items do not require further evaluation because the structure and aging effect combination is covered by the Structures Monitoring Program. The Structures Monitoring Program monitors settlement for each major structure using geotechnical monitoring techniques with differential and total settlements being found to be acceptable, and STP does not have porous concrete subfoundations or an active dewatering system.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.26. The staff noted that the applicant uses the Structures Monitoring Program to manage 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 for these groups of structures. The staff reviewed UFSAR Appendix 2.5C and confirmed that the applicant uses geotechnical monitoring to measure settlements of facility structures. The staff also noted that the UFSAR makes no reference to any porous concrete subfoundations or the existence of an active dewatering system at STP. In its review of components associated with item 3.5.1.28 and SRP-LR Section 3.5.2.2.2.2, item 3, the staff finds that the applicant meets the further evaluation criteria because it manages cracks and distortion due to increased stress levels from settlement using the Structures Monitoring Program, porous concrete subfoundations do not exist at STP, and a dewatering system is not used to lower the groundwater level.

Based on the evaluation provided, the staff determines that the applicant meets the further evaluation criteria of SRP-LR Section 3.5.2.2.2.2, item 3. For those items that apply to LRA Section 3.5.2.2.2.2.3, 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).

(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 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, such as exterior walls below grade and foundations of Groups 1–3, 5, and 7–9 structures exposed to a buried environment (LRA defined, GALL Report equivalent: groundwater and soil environment), which will be managed for increase in porosity and permeability, cracking, loss of material (spalling, scaling), and loss of bond due to aggressive chemical attack and corrosion of embedded steel exposed to a groundwater and soil environment by the Structures Monitoring Program. The criteria in SRP-LR Section 3.5.2.2.2.2, item 4, state that 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. The SRP-LR also states that further evaluation of the plant-specific programs to manage these aging effects in inaccessible areas of these groups of structures is recommended if the environment is aggressive. GALL Report items III.A3-4 and III.A3-5 state that for inaccessible areas of plants with non-aggressive groundwater or soil (i.e., pH greater than 5.5, chlorides less than 500 ppm, and sulfates less than 1,500 ppm), the applicant should consider examinations of exposed portions of the below-grade concrete when excavated for any reason, as well as periodic monitoring of below-grade water chemistry, including consideration of potential seasonal variations. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the reinforced concrete structures were designed, constructed, and inspected in accordance with ACI and ASTM standards that provide for good quality, dense, well-cured, and low permeability concrete. The applicant also stated that procedural controls were used to ensure quality throughout the batching, mixing, and placement processes. The applicant further stated that crack control was achieved through proper sizing, spacing, and distribution of reinforcing steel in accordance with the proposed ACI 359 and ASME Code Section III, Division 2; groundwater chemistry is monitored; and opportunistic inspections are performed whenever inaccessible concrete is exposed.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.26. The staff reviewed UFSAR Section 3.8.1.6, "Material, Quality Control, and Special Construction Techniques," Subsection 3.8.1.6.1, "Concrete," and Subsection 3.8.1.6.1.1, "Materials," and noted that the reinforced concrete structures were designed, constructed, and inspected in accordance with ACI and ASTM standards that provide for good quality, dense, well-cured, and low permeability concrete. The LRA indicates that the groundwater chemistry is monitored, and opportunistic inspections are performed whenever inaccessible concrete is exposed. The staff, however, noted that the applicant failed to demonstrate that the groundwater or soil adjacent to the inaccessible concrete structures is not aggressive and that the groundwater is monitored to address seasonal variations. This was addressed during the onsite audit of the Structures Monitoring Program, and, subsequently, the issue was resolved through RAI B2.1.32-4, which is documented in SER Section 3.0.3.2.26.

In its review of components associated with item 3.5.1.31 and SRP-LR Section 3.5.2.2.2.2, item 4, the staff finds that the applicant meets the further evaluation criteria because it has used appropriate construction methods and standards that provide for good quality, dense, well-cured, low permeability concrete that mitigate potential aggressive chemical attacks on concrete and reinforcing steel deteriorations (i.e., cracking, spalling, scaling, loss of material and bond). Additionally, it has enhanced its Structures Monitoring Program to further monitor the site groundwater at least twice every 5 years for pH, sulfates, and chlorides and take corrective actions as necessary.

Based on the evaluation provided, the staff determines that the applicant meets the further evaluation criteria of SRP-LR Section 3.5.2.2.2.2, item 4. For those items that apply to LRA Section 3.5.2.2.2.2.4, 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).

(5) Increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide in below-grade inaccessible concrete areas of Groups 1–3, 5, and 7–9 structures

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 of Groups 1–3, 5, and 7–9 structures exposed to a buried environment (LRA defined, GALL Report equivalent: flowing water environment), which will be managed for increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide by the Structures Monitoring Program. The criteria in SRP-LR Section 3.5.2.2.2.2, item 5, state that 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. The SRP-LR also states that further evaluation is recommended for this aging effect for inaccessible areas of these groups of structures if concrete was not constructed in accordance with the recommendations in ACI 201.2R-77. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the reinforced concrete structures were designed, constructed, and inspected in accordance with ACI and ASTM standards (e.g., ACI 211.1-70 for concrete mix design), which provide for a good quality, dense, well-cured, and low permeability concrete, and the Structures Monitoring Program is used to manage aging; therefore, further evaluation for the effects of leaching of calcium hydroxide is not required.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.26. The staff reviewed UFSAR Section 3.8.1.6, "Material, Quality Control, and Special Construction Techniques," Subsection 3.8.1.6.1, "Concrete," and Subsection 3.8.1.6.1.1, "Materials," and noted that the reinforced concrete structures were designed, constructed, and inspected in accordance with ACI and ASTM standards that provide for good quality, dense, well-cured, and low permeability concrete. Laboratory trial batches, and the subsequent mix adjustments, were in accordance with ACI 211.1-70, "Recommended Practice for Normal Weight Concrete," which references ACI 201.2R. This was also stated by the applicant in its response to RAI 3.5.2.2.2-1, elaborated above under item 3.5.1.15 and item 3.5.1.27. In its review of components associated with item 3.5.1.32 and SRP-LR Section 3.5.2.2.2.2, item 5, the staff finds the applicant meets the further evaluation criteria because the requirements of ACI 201.2R are incorporated into ACI 211.1 by reference, which the applicant used in the design and adjustments of its concrete mixes.

Based on the programs identified, the staff determines that the applicant's evaluation meets SRP-LR Section 3.5.2.2.2.2, item 5, further evaluation criteria. For those items that apply to LRA Section 3.5.2.2.2.2.5, 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).

Item 3—Reduction of Strength and Modulus of Concrete Structures Due to Elevated Temperature. LRA Section 3.5.2.2.2.3 states that LRA Section 3.5.2.2.2.3, associated with LRA Table 3.5.1, item 3.5.1.33, addresses concrete components exposed to an air-indoor uncontrolled environment, which will be managed for reduction of strength and modulus of elasticity by the Structures Monitoring Program. The criteria in SRP-LR Section 3.5.2.2.2.3 states that reduction in strength and modulus of elasticity of concrete could occur in any concrete element subjected to temperatures that exceed limits in ACI 349-85 of approximately 66 °C (150 °F) for general areas and approximately 93 °C (200 °F) for local areas. The SRP-LR also states that if any portion of a safety-related or other concrete structure exceeds the specified limits, further evaluation of a plant-specific program is recommended. The applicant addressed the further evaluation criteria by stating that this item is not applicable because none of the STP concrete structures are exposed to temperatures above the SRP-LR limits, and because penetrations and supports are designed so that the concrete temperatures do not exceed approximately 66 °C (150 °F) for general areas or approximately 93 °C (200 °F) for local areas during long-term, accident, or short-term loading. The applicant also stated that, if required, insulation or cooling systems or both are provided to limit the concrete temperatures to acceptable levels. The applicant further stated that penetration seals are designed to prevent heat from pipes or cables from raising the temperature in the surrounding concrete or masonry above approximately 93 °C (200 °F), and accessible concrete components are monitored by the Structures Monitoring Program to confirm absence of any visible effects due to elevated temperatures.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.26. The staff reviewed UFSAR and STP TS and noted that no in-scope STP concrete structures exceed the SRP-LR limits. In its review of components associated with item 3.5.1.33 and SRP-LR Section 3.5.2.2.2.3, the staff finds that the applicant meets the further evaluation criteria because no in-scope concrete structures are exposed to temperatures above the SRP-LR limits, and the Structures Monitoring Program will be used to monitor accessible concrete components to confirm absence of any visible effects due to elevated temperatures.

Based on the program identified, the staff determines that the applicant's evaluation meets SRP-LR Section 3.5.2.2.2.3 further evaluation criteria. For those items that apply to LRA Section 3.5.2.2.2.3, 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).

Item 4—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, 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 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 of Group 6 structures exposed to an atmosphere and weather, plant indoor air, buried environments (LRA defined, GALL Report equivalent: air-indoor uncontrolled or air-outdoor, groundwater and soil environments), which will be 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 by the

RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The criteria in SRP-LR Section 3.5.2.2.2.4, item 1, state that increase in porosity and permeability, cracking, loss of material (spalling, scaling), aggressive chemical attack and cracking, loss of bond, and loss of material (spalling, scaling), and corrosion of embedded steel could occur in below-grade inaccessible concrete areas of Group 6 structures. The SRP-LR also states that if the environment is aggressive, further evaluation of plant-specific programs to manage these aging effects is recommended. In addition, GALL Report items III.A6-1 and III.A6-3 note that for inaccessible areas of plants with non-aggressive groundwater and soil (i.e., pH greater than 5.5, chlorides less than 500 ppm, and sulfates less than 1,500 ppm), as a minimum, the following should be considered: (1) examinations of the exposed portions of the below-grade concrete, when excavated for any reason, and (2) periodic monitoring of below-grade water chemistry, including consideration of potential seasonal variations. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the reinforced concrete structures were designed, constructed, and inspected in accordance with ACI and ASTM standards that provide for good quality, dense, well-cured, and low permeability concrete. The applicant also stated that procedural controls were used to ensure quality throughout the batching, mixing, and placement processes; that crack control was achieved through proper sizing, spacing, and distribution of reinforcing steel in accordance with the Proposed ACI 359 and ASME Code Section III, Division 2; groundwater chemistry is monitored; and opportunistic inspections are performed whenever inaccessible concrete is exposed. The applicant further stated that these aging effects and mechanisms will be managed by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, as integrated with the Structures Monitoring Program.

The staff's evaluations of the applicant's RG 1.127, Inspection of Water-Control Structures Program and Structures Monitoring Program are documented in SER Sections 3.0.3.2.27 and 3.0.3.2.26, respectively. The staff noted that inspections of Group 6 structures are performed under the RG 1.127, Inspection of Water-Control Structures Inspection Program, which, with an enhancement to specify inspections at intervals not to exceed 5 years or to follow significant natural phenomena, is consistent with the elements of the GALL Report "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program." The staff also reviewed the UFSAR and noted, as elaborated above in SER Section 3.5.2.2 for items 3.5.1.1, 3.5.1.6, and 3.5.1.15, that the reinforced concrete structures were designed, constructed, and inspected in accordance with ACI and ASTM standards that provide for good quality, dense, well-cured, and low permeability concrete. The staff also noted that the applicant's RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, through its integration with the enhanced Structures Monitoring Program, monitors—as documented in SER Section 3.0.3.2.26—the site groundwater at least twice every 5 years for pH, sulfates, and chlorides and takes corrective actions as necessary for potential aggressive chemical attacks on concrete and reinforcing steel.

In its review of components associated with item 3.5.1.34 and SRP-LR 3.5.2.2.2.4, item 1, the staff finds that the applicant meets the further evaluation criteria because it has used appropriate construction methods and standards that provide for good quality, dense, well-cured, low permeability concrete to mitigate potential aggressive chemical attacks on concrete and reinforcing steel deteriorations (i.e., cracking, spalling, scaling, loss of material and bond), and it enhanced its Structures Monitoring Program to further monitor the site groundwater at least twice every 5 years for pH, sulfates, and chlorides and take corrective actions as necessary.

Based on the programs identified, the staff determines that the applicant's evaluation meets the further evaluation criteria of SRP-LR Section 3.5.2.2.2.4, item 1. For those items that apply to LRA Section 3.5.2.2.2.4.1, 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).

(2) Loss of material (spalling, scaling) and cracking due to freeze-thaw 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 exterior above- and below-grade concrete foundation of Group 6 structures exposed to an atmosphere and weather environment (LRA defined, GALL Report equivalent: air-outdoor environment), which will be managed for loss of material (scaling, cracking, and spalling) due to freeze-thaw by RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The criteria in SRP-LR Section 3.5.2.2.2.4, item 2, state that loss of material (spalling, scaling) and cracking due to freeze-thaw that could occur in below-grade inaccessible concrete areas of Group 6 structures. The SRP-LR also states that for plants located in moderate to severe weathering conditions, further evaluation is recommended. The applicant addressed the further evaluation criteria by stating that aging is managed by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, as integrated with the Structures Monitoring Program, and that STP is located in a weathering zone classified as “Negligible” in accordance with Figure 1 of ASTM C33-07; therefore, this AERM is not applicable.

The staff's evaluations of the applicant's RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program and the Structures Monitoring Program are documented in SER Sections 3.0.3.2.27 and 3.0.3.2.26, respectively. The staff noted that aging is managed collectively by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program and the Structures Monitoring Program. The staff also reviewed the UFSAR and ASTM C33, as noted for example in SER Table 3.5.1, items 3.5.1.14 and 3.5.1.26, and confirmed that STP is located in a mild climate with a weathering zone classified as “Negligible.” In its review of components associated with item 3.5.1.35 and SRP-LR 3.5.2.2.2.4, item 2, the staff finds the applicant meets the further evaluation criteria because aging is managed by the RG1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, as integrated with the Structures Monitoring Program, and that STP is located in a “Negligible” weathering zone.

Based on the program identified, the staff determines that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.5.2.2.2.4, item 2. For those items that apply to LRA Section 3.5.2.2.2.4.2, the staff determines 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) Cracking due to expansion and reaction with aggregates and increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide in below-grade inaccessible reinforced concrete areas of Group 6 structures

LRA Section 3.5.2.2.2.4.3, associated with LRA Table 3.5.1, item 3.5.1.36, addresses all accessible and inaccessible reinforced concrete components of Group 6 structures exposed to an atmosphere and weather, plant indoor air environments (LRA defined, GALL Report equivalent: any environment), which will be managed for cracking due to expansion and reaction with aggregates by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The criteria in SRP-LR Section 3.5.2.2.2.4, item 3, state that cracking due to expansion and reaction with aggregates could occur in below-grade inaccessible reinforced concrete areas of Group 6 structures. The SRP-LR also states that further evaluation is recommended if the concrete was not constructed in accordance with recommendations in ACI 201.2R-77. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the aggregate was found to be potentially reactive when evaluated in accordance with an appendix to ASTM C33-74, and, as a result, low-alkali cement was used in the concrete. The applicant also stated that accessible concrete components are monitored by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program to confirm the absence of any visible effects due to reaction with aggregate; therefore, further evaluation of the effects of reaction with aggregates is not required.

The staff's evaluations of the applicant's RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program and Structures Monitoring Program are documented in SER Sections 3.0.3.2.27 and 3.0.3.2.26, respectively. The staff noted that the applicant evaluated the aggregate material for potential reactivity through guidance in an appendix to ASTM C33 that references test methods provided in ASTM C289 and ASTM C295, that low-alkali cement was used in the concrete mixtures to reduce the potential for alkali-aggregate reactions and that visible surfaces are inspected through the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program for signs of cracking that would indicate occurrence of such reactions. In its review of components associated with item 3.5.1.36, the staff finds that the applicant meets the further evaluation criteria because the accessible components are monitored under the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, as integrated with the Structures Monitoring Program, which provides inspections and monitoring for potential aggregate reactivity. Additionally, the aggregate materials have been evaluated for potential reactivity, and low-alkali cement was used in the concrete mixtures.

Based on the program identified, the staff determines that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.5.2.2.2.4, item 3. For those items that apply to LRA Section 3.5.2.2.2.4.3, the staff determines 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).

LRA Section 3.5.2.2.2.4.3, associated with LRA Table 3.5.1, item 3.5.1.37, addresses exterior above- and below-grade reinforced concrete foundation interior slab and components of Group 6 structures exposed to a submerged environment (LRA defined, GALL Report equivalent: water-flowing environment), which will be managed for loss of strength due to leaching of calcium hydroxide by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The criteria in SRP-LR Section 3.5.2.2.2.4, item 3, state that leaching of calcium hydroxide could occur in below-grade inaccessible reinforced concrete areas of Group 6 structures. The SRP-LR also states that further evaluation is recommended if the concrete was not constructed in accordance with recommendations in ACI 201.2R-77. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the reinforced concrete structures were designed, constructed, and inspected in accordance with ACI and ASTM standards that provide for good quality, dense, well-cured, and low permeability concrete. The applicant also stated that procedural controls were used to ensure quality throughout the batching, mixing, and placement processes. The applicant further stated that these aging effects and mechanisms will be managed by the RG1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program.

The staff's evaluation of the applicant's RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program is documented in SER Section 3.0.3.2.27. The staff reviewed the UFSAR and noted that the reinforced concrete structures were designed, constructed, and inspected in accordance with ACI and ASTM standards, which provide for good quality, dense, well-cured, and low permeability concrete. The staff also noted that procedural controls were used to ensure quality throughout the batching, mixing, and placement processes and that accessible components are monitored under the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The staff also noted that the applicant used ACI 201.2R, as incorporated by reference in ACI 211.1, which was documented by the staff in SER Section 3.5.2.2, for example, in items 3.5.1.6, 3.5.1.15, and 3.5.1.27.

In its review of components associated with item 3.5.1.37 and SRP-LR 3.5.2.2.2.4, item 3, the staff finds the applicant meets the further evaluation criteria because concrete batched during construction were in accordance with ACI 211.1, which references ACI 201.2R, and aging is managed by the RG1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, as integrated with the enhanced Structures Monitoring Program, which provides inspections and monitoring to mitigate potential aggressive chemical attacks.

Based on the programs identified, the staff determines that the applicant's evaluation meets the further evaluation criteria of SRP-LR Section 3.5.2.2.2.4, item 3. For those items that apply to LRA Sections 3.5.2.2.2.4.3, 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).

<u>Item 5—Cracking Due to Stress-Corrosion Cracking and Loss of Material Due to Pitting and Crevice Corrosion</u>. LRA Table 3.5.1, item 3.5.1.38, addresses Group 7 and 8 stainless steel tank liners exposed to standing water, which will be managed for cracking due to SCC and loss of material due to pitting and crevice corrosion, and states that this item is not applicable because the in-scope tank liners were evaluated as tanks with their mechanical systems and assigned to GALL Report lines from GALL Report, Chapters VII and VIII. In its review, the staff noted that the in-scope tank liners were evaluated as tanks with their mechanical systems and assigned to GALL Report lines from GALL Report, Chapters VII and VIII; therefore, the staff finds the applicant's determination acceptable.

Item 6—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 Groups B2–B5 steel supports, welds, bolted connections, support anchorage to building structures exposed to an atmosphere and weather, plant indoor air environments (LRA defined, GALL Report equivalent: air-indoor uncontrolled or air-outdoor environment), which will be managed for loss of material due to general and pitting corrosion by the Structures Monitoring Program. The criteria in SRP-LR Section 3.5.2.2.2.6, item 1, state that loss of material due to general and pitting corrosion of Groups B2–B5 supports could occur. The SRP-LR also states that further evaluation of the component support and aging effect combination is recommended if the aging effect is not managed by the Structures Monitoring Program. The applicant addressed the further evaluation criteria of the SRP-LR by stating that this item does not require further evaluation because it is covered by the Structures Monitoring Program.

The staff's evaluation of the Structures Monitoring Program is documented in SER Section 3.0.3.2.26. The staff noted that the structure-aging effect combination is covered by the Structures Monitoring Program. In its review of components associated with item 3.5.1.39, the staff finds that the applicant meets the further evaluation criteria because aging is managed by the SRP-LR recommended program.

Based on the program identified, the staff determines that the applicant's evaluation meets the further evaluation criteria of SRP-LR Section 3.5.2.2.2.6, item 1. For those items that apply to LRA Sections 3.5.2.2.2.6, 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).

(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 building concrete at locations of expansion and grouted anchors and grout pads for support base plates for Groups B1–B5 supports exposed to an atmosphere and weather, plant indoor air environments (LRA defined, GALL Report equivalent: air-indoor uncontrolled or air-outdoor environment), which will be managed for reduction in anchor capacity by the Structures Monitoring Program. The criteria in SRP-LR Section 3.5.2.2.2.6, item 2, state that reduction in concrete anchor capacity due to degradation of the surrounding concrete for Groups B1–B5 supports could occur. The SRP-LR also states that further evaluation of the component support and aging effect combination is recommended if the aging effect is not managed by the Structures Monitoring Program. The applicant addressed the further evaluation criteria of the SRP-LR by stating that this item does not require further evaluation because it is covered by the Structures Monitoring Program.

The staff's evaluation of the Structures Monitoring Program is documented in SER Section 3.0.3.2.26. The staff noted that the structure and aging effect combination is covered by the Structures Monitoring Program. In its review of components associated with item 3.5.1.40, the staff finds that the applicant met the further evaluation criteria because aging is managed by the SRP-LR recommended program.

Based on the program identified, the staff determines that the applicant's evaluation meets the further evaluation criteria of SRP-LR Section 3.5.2.2.2.6, item 2. For those items that apply to LRA Sections 3.5.2.2.2.6, 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) Reduction and Loss of Isolation Function Due to Degradation of Vibration Isolation Elements for Group B4 Supports

LRA Table 3.5.1, item 3.5.1.41, addresses non-metallic vibration elements exposed to an air environment, which will be managed for reduction or loss of isolation function for Group 4 supports, and states that this item is not applicable because there are no vibration isolation elements in-scope for license renewal at STP. In its review of LRA Sections 2 and 3, the staff confirmed that there are no vibration isolation elements in-scope for license renewal; therefore, the staff finds the applicant's determination acceptable.

Item 7—Cumulative Fatigue Damage Due to Cyclic Loading. LRA Table 3.5.1, item 3.5.1.42, addresses Group B1.1, Group B1.2, and Group B1.3 component supports (for ASME Code Class 1, 2, and 3 piping and components and for Class MC BWR containment supports) exposed to an indoor uncontrolled or outdoor air, which will be managed for fatigue by a TLAA. The criteria in the SRP-LR Section 3.5.2.2.2.7 state that fatigue of component support members, anchor bolts, and welds for Groups B1.1, B1.2, and B1.3 component supports is a TLAA, as defined in 10 CFR 54.21(c), only if a CLB fatigue analysis exists. The applicant addressed the further evaluation criteria by stating that fatigue analyses for these components were not included as part of the CLB. In its review, the staff noted that fatigue analyses for these components were not included as part of the CLB; therefore, the staff finds the applicant's determination acceptable.

3.5.2.2.3 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's QA Program.

3.5.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.5.2-1 through 3.5.2-11, 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 3.5.2-11, the applicant indicated, via notes F through 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 whether 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. The staff's evaluation is documented in the following sections.

3.5.2.3.1 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—Containment Building

Fire Barrier Coatings and Wraps Exposed to Plant Indoor Air. In LRA Tables 3.5.2-1, 3.5.2-2, 3.5.2-5, and 3.5.2-8, the applicant stated that fire barrier coatings and wraps exposed to plant indoor air will be managed for loss of material and cracking by the Fire Protection Program. The AMR items cite generic note J and plant-specific notes 1 or 2, which both state that the GALL Report does not provide a line in which fire barriers (ceramic fiber or cementitious coating) are inspected per the Fire Protection Program.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noted that the ceramic fiber and cementitious fire barrier coatings and wraps consist of comparable substances to those used in fire barrier walls, ceilings, and floors, as discussed in GALL Report AMP XI.M26, "Fire Protection." GALL Report AMP XI.M26 manages loss of material and cracking for fire barrier walls, ceilings, floors, and other fire resistant materials, which serve a fire barrier function. Based on its review of the GALL Report, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Fire Protection Program is documented in SER Section 3.0.3.2.9. The staff noted that the Fire Protection Program includes periodic visual inspections of fire barrier walls, ceilings, floors, coatings, and wraps for cracking, spalling, and loss of material, which is consistent with the recommendations in GALL Report AMP XI.M26. The staff finds the applicant's proposal to manage aging using the Fire Protection Program acceptable because the program includes periodic visual inspections, which are capable of detecting loss of material and cracking for fire barriers, and the construction material, environment, and AERM are equivalent to those of the fire barrier walls, ceilings, floors for which GALL Report recommends AMP XI.M26, "Fire Protection," to manage aging.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations for items in LRA Tables 3.5.2-1, 3.5.2-2, 3.5.2-5, and 3.5.2-8 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 functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Coatings Exposed to Plant Indoor Air. In LRA Table 3.5.2-1, the applicant stated that coatings exposed to plant indoor air will be managed for loss of coating integrity by the Protective Coatings Monitoring and Maintenance Program. The AMR item cites generic note J and plant-specific note 4, which both state that the GALL Report does not provide a line in which coatings are inspected per the Protective Coatings Monitoring and Maintenance Program.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the GALL Report and ASTM D5163, which provides guidelines that are acceptable for establishing an inservice coatings monitoring program for Service Level 1 coating systems, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Protective Coatings Monitoring and Maintenance Program is documented in SER Section 3.0.3.3.4. The staff finds the applicant's proposal to manage aging using the Protective Coatings Monitoring and Maintenance Program acceptable because the applicant will identify defective or deficient coatings and perform repairs in accordance with ASTM D5163. In addition, degraded coatings will be documented and summarized for further evaluation and trending, which is consistent with 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 functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a).

3.5.2.3.2 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—Control Room

The staff's evaluation for fire barrier coatings and wraps exposed to plant indoor air (structural) (external), which will be managed for loss of material and cracking by the Fire Protection Program and cite generic note J, is documented in SER Section 3.5.2.4.1

<u>Gypsum and plaster barriers exposed to plant indoor air (structural) (external)</u>. In LRA Tables 3.5.2-2, 3.5.2-5, and 3.5.2-6, the applicant stated that the gypsum and plaster barriers exposed to plant indoor air (structural) (external) will be managed for cracking by the Structures Monitoring Program. For those gypsum and plaster barriers that have a fire barrier function, cracking is also managed by the Fire Protection Program, as documented in SER Section 3.5.2.3.5. The AMR items cite generic note J, indicating that the GALL Report does not evaluate either the component or the material and environment combination. The staff reviewed all AMR result lines in the GALL Report where the component and material is gypsum or plaster barriers and confirmed that there are no entries for this component, material, and environment combination where the aging effect is cracking.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.26. The staff noted that the applicant's Structures Monitoring Program conducts visual inspections to monitor the condition of structures and structural supports that are within the scope of license renewal to manage cracking. The staff finds the applicant's proposal to manage aging using the Structures Monitoring Program acceptable because the program periodically performs visual inspections that are capable of detecting cracking of gypsum and plaster barriers that are used for intended functions of structural support, fire barriers, and shelter or protection.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations for items in LRA Tables 3.5.2-2, 3.5.2-5, and 3.5.2-6 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 functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3.3 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—Diesel Generator Building

No additional review was required for the diesel generator building.

3.5.2.3.4 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—Turbine Generator Building

No additional review was required for the turbine generator building.

3.5.2.3.5 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—Mechanical-Electrical Auxiliary Building

The staff's evaluation for gypsum and plaster barriers exposed to plant indoor air environment, which will be managed for cracking by the Structures Monitoring Program and cite generic note J, is documented in SER Section 3.5.2.4.2.

The staff's evaluation for fire barrier coatings and wraps exposed to plant indoor air (structural) (external), which will be managed for loss of material and cracking by the Fire Protection Program and cite generic note J, is documented in SER Section 3.5.2.4.1

<u>Gypsum and Plaster Barriers Exposed to Plant Indoor Air</u>. In LRA Table 3.5.2-5, the applicant stated that gypsum and plaster barriers with a fire barrier function exposed to plant indoor air will be managed for cracking by the Fire Protection and Structures Monitoring programs. The AMR items cite generic note J.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noted that the gypsum and plaster barriers consist of comparable substances to those used in fire barrier walls, ceilings, and floors and other fire resistant materials, as discussed in GALL Report AMP XI.M26, "Fire Protection." The GALL Report recommends AMP XI.M26, "Fire Protection," and AMP XI.S6, "Structures Monitoring," to manage cracking and spalling for reinforced concrete structural fire barrier walls, ceilings, floors, and other fire resistant materials that serve a fire barrier function. The staff also noted that, in conducting visual examinations for cracking, spalling of the gypsum and plaster material would be evident. Based on its review of the GALL Report, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination or would identify them during inspections.

The staff's evaluations of the applicant's Fire Protection and Structures Monitoring programs are documented in SER Sections 3.0.3.2.9 and 3.0.3.2.26, respectively. The staff noted that the

Fire Protection Program includes periodic visual inspections of fire barrier walls, ceilings, floors, and other fire resistant materials for cracking, spalling, and loss of material, which is consistent with the recommendations in GALL Report AMP XI.M26. The staff also noted that the Structures Monitoring Program includes visual inspections of structures for cracking and loss of material. The staff finds the applicant's proposal to manage aging using the Fire Protection and Structures Monitoring programs acceptable because the programs include periodic visual inspections, which are capable of detecting loss of material, cracking, and spalling for fire barriers, and the construction material, environment, and AERM are equivalent to those of the fire barrier walls, ceilings, and floors for which GALL Report recommends AMP XI.M26, "Fire Protection," to manage aging.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations for items in LRA Table 3.5.2-5 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 functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3.6 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—Miscellaneous Yard Areas and Buildings

The staff's evaluation for gypsum and plaster barriers exposed to plant indoor air environment, which will be managed for cracking by the Structures Monitoring Program and cite generic note J, is documented in SER Section 3.5.2.4.2.

3.5.2.3.7 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—Electrical Foundations and Structures

No additional review was required for the electrical foundations and structures.

3.5.2.3.8 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—Fuel Handling Building

The staff's evaluation for fire barrier coatings and wraps exposed to plant indoor air (structural) (external), which will be managed for loss of material and cracking by the Fire Protection Program and cite generic note J, is documented in SER Section 3.5.2.4.1.

3.5.2.3.9 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—Essential Cooling Water Structures

No additional review was required for the ECW structures.

3.5.2.3.10 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—Auxiliary Feedwater Storage Tank Foundation and Shell

No additional review was required for the AFST foundation and shell.

3.5.2.3.11 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—Supports

Components Managed for Loss of Material. In LRA Table 3.5.2-11, the applicant stated that mechanical equipment stainless steel supports (non-ASME Code) exposed to a submerged (structural) (external) environment, will be managed for loss of material by the Structures Monitoring Program. The AMR items cite generic note J, indicating that the GALL Report does not evaluate either the component or the material and environment combination. The staff reviewed all AMR result lines in the GALL Report where the component and material is mechanical equipment stainless steel supports (non-ASME) and confirmed that there are no entries for this component, material, and environment combination where the aging effect is loss of material.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. During its review, the staff noted that LRA Table 3.5.2-11 lists stainless steel supports in a submerged environment and does not include cracking as an applicable aging effect. The GALL Report lists cracking due to SCC as a possible aging effect and recommends appropriate aging management, as summarized in GALL Report AMP XI.M32, "One-Time Inspection." Therefore, by letter dated September 22, 2011, the staff issued RAI 3.5.2.3.11-1 requesting that the applicant justify why cracking is not an applicable aging effect for submerged stainless steel supports or include an appropriate AMP to manage cracking in submerged stainless steel supports.

In its response dated November 21, 2011, the applicant stated that the GALL Report, Chapter IX.D, specifies the temperature threshold for SCC in stainless steel as approximately 60 °C (140 °F). The stainless steel supports in a submerged environment listed in LRA Table 3.5.2-11 are located in ECW system structures. The applicant further stated that the water temperature in these structures does not exceed approximately 60 °C (140 °F); therefore, SCC is not an AERM for these components.

The staff reviewed UFSAR Section 9.7.5.2 and the TS and confirmed that ECW system temperatures remain below the threshold of approximately 60 °C (140 °F), which is the threshold temperature for the initiation of SCC. The staff finds the applicant's response acceptable because the maximum inlet and outlet water temperatures where the stainless steel supports are located remain below the SCC initiation temperature of approximately 60 °C (140 °F).

The staff's evaluation of the applicant's Structures Monitoring Program is documented in Section 3.0.3.2.26. The staff noted that the applicant's Structures Monitoring Program conducts visual inspections to monitor the condition of structures and structural supports that are within the scope of license renewal to manage cracking. The staff finds the applicant's proposal to manage aging using the Structures Monitoring Program acceptable because the program periodically performs visual inspections that are capable of detecting loss of material of mechanical equipment stainless steel supports (non-ASME Code) exposed to a submerged (structural) (external) 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 for items in LRA Table 3.5.2-11 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 functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Components Managed for Loss of Preload. In LRA Table 3.5.2-11, as amended by letter dated November 21, 2011, the applicant stated that high-strength, low-alloy steel bolts exposed to a plant indoor air environment will be managed for loss of preload by the ASME Section XI, Subsection IWF Program. The AMR item cites generic note H. This item also cites plant-specific note 2, which states, "[the] GALL [Report] Revision 1 does not identify Loss of Preload as an AERM for structural bolting. This line is consistent with [the] GALL Report, Revision 2, item III.B1.1.TP-229."

The staff noted that this material and environment combination is identified in the GALL Report, Revision 1, which addresses high-strength, low-alloy steel bolting exposed to plant indoor air-uncontrolled and recommends the Bolting Integrity Program to manage cracking and loss of material. However, the applicant has identified loss of preload as an additional aging effect and proposes to manage it using the ASME Section XI, Subsection IWF Program, consistent with the GALL Report, Revision 2, item III.B1.1.TP-229.

The staff's evaluation of the applicant's ASME Section XI, Subsection IWF Program is documented in SER Section 3.0.3.2.24. The applicant added this item as a result of RAI 3.5.2.11-1, in which the staff asked the applicant to review whether the aging effect of loss of preload is applicable to low-alloy, high-strength steel bolting. The staff's review and resolution of RAI 3.5.2.11-1 is documented in SER Section 3.0.3.2.5. The loss of preload aging effect was not included in the GALL Report, Revision 1, but has been incorporated into the GALL Report, Revision 2. The staff finds the applicant's proposal to manage the loss of preload aging effect for high-strength, low-alloy steel bolting using the ASME Section XI, Subsection IWF Program acceptable because it is consistent with GALL Report, Revision 2, recommendations. Further, the staff noted that the applicant will supplement the management of aging effects for high-strength, low-alloy steel bolting through the Bolting Integrity AMP, which incorporates recommendations delineated in NUREG-1339 and industry recommendations delineated in EPRI Reports NP-5769, NP-5067, and TR-104213 for high-strength structural bolting. These recommendations provide guidelines for proper selection of bolting material, lubricants, sealants, and installation procedures to prevent or minimize loss of bolting preload and to mitigate degradation of structural bolting.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations for items in LRA Table 3.5.2-11 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 functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Copper Alloy Mechanical Equipment Supports (Class 2 and 3) Exposed to a Submerged (Structural) (External) Environment. In LRA Table 3.5.2-11, as revised by letter dated October 22, 2014, the applicant stated that copper alloy mechanical equipment supports (Class 2 and Class 3) exposed to a submerged (structural) (external) environment, will be managed for loss of material by the ASME Section XI, Subsection IWF Program. LRA Table 2.4-7 states that the component intended function is to provide structural support and LRA Table 3.0-2 defines the submerged (structural) environment as one in which SCs are covered with water. The AMR item cites generic note J indicating that neither the component nor the material and environment combination are evaluated in the GALL Report. The AMR item also cites plant-specific note 3 which states, in part, that the ASME Section XI, Subsection IWF Program "manages the aging of the ECW pump column copper alloy supports when the pump is removed for maintenance."

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review, the staff notes that although GALL Report, Revision 2, does not specifically evaluate copper alloy supports exposed to a submerged (water) environment, it does evaluate similar components made of copper alloy and exposed to a raw water environment, such as those in AMR items VII.C1.AP-179, VII.C1.AP-196, VII.E5.AP-271, and VII.G.AP-197. For these items the GALL Report states that copper alloy components exposed to raw water are susceptible to loss of material; therefore, the staff finds that the applicant identified all credible aging effects for this component, material, and environment combination. The staff also notes that the GALL Report recommends the ASME Section XI, Subsection IWF Program for the inspection of Class 2 and 3 component supports.

The staff's evaluation of the applicant's ASME Section XI, Subsection IWF Program is documented in SER Section 3.0.3.2.24. The staff finds the applicant's proposal to manage aging effects using the ASME Section XI, Subsection IWF Program acceptable because the program performs VT-3 visual examinations of Class 2 and 3 component supports once every 10 years, consistent with the ASME Code Section XI, Subsection IWF, and these examinations are capable of detecting loss of material of copper alloy supports exposed to a submerged environment prior to a loss of intended function.

On the basis of its review, the staff concludes for items in LRA Table 3.5.2-11 with an AERM, that the applicant demonstrated that the effects of aging for these items will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.3 Conclusion

The staff concludes that 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 such 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).

3.6 Aging Management of Electrical Commodity Group

The information in this section documents the staff's review of the applicant's AMR results for the following electrical components, instrumentation and control (I&C) components, and component groups:

- cable connections (metallic parts)
- connectors (exposed to borated water)
- high-voltage insulators
- insulated cable and connections
- metal enclosed bus
- switchyard bus and connections
- transmission conductors and connections

3.6.1 Summary of Technical Information in the Application

LRA Section 3.6 provides AMR results for the electrical and I&C components and commodity groups. LRA Table 3.6.1, "Summary of Aging Management Evaluations in Chapter VI of NUREG-1801 for Electrical Components," 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 whether the applicant provided sufficient information to demonstrate that the effects of aging for the electrical and I&C components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended 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 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 confirm that the material presented in the LRA was applicable and that the applicant 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 environmental qualification (EQ) requirements (3.6.1.1)	Degradation due to various aging mechanisms	Environmental Qualification of Electric Components	Yes	TLAA Environmental Qualification of Electric Components	EQ is a TLAA (see SER Section 3.6.2.2.1 and Section 4.4)

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
Electrical cables, connections and fuse holders, and electrical (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 Environmental Qualification Requirements	No	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program	Consistent with the GALL Report (see SER Section 3.6.2.1)
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 (IR) (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 Environmental Qualification Requirements Used In Instrumentation Circuits	No	Not Applicable	Not applicable; all electrical cables and connections used in high-voltage instrumentation circuits that support license renewal intended functions are subject to 10 CFR 50.49 EQ requirements and are managed by the EQ of Electrical Components program
Conductor insulation for inaccessible medium-voltage and low-voltage (400 V 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 Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	No	Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program	Consistent with the GALL Report
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 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
Fuse Holders (Not Part of a Larger Assembly): Fuse holders—metallic clamp (3.6.1.6)	Fatigue due to ohmic heating, thermal cycling, electrical transients, frequent manipulation, vibration, chemical contamination, corrosion, and oxidation	Fuse Holders	No	Not applicable	Not applicable; all fuse holders including the fuses installed for electrical penetration protection are part of larger assemblies (see SER Section 3.6.2.1.1)
Metal enclosed bus—Bus/connections (3.6.1.7)	Loosening of bolted connections due to thermal cycling and ohmic heating	Metal Enclosed Bus	No	Metal Enclosed Bus	Consistent with the GALL Report
Metal enclosed bus—Insulation/insulators (3.6.1.8)	Reduced insulation resistance and electrical failure due to various physical, thermal, radiolytic, photolytic, and chemical mechanisms	Metal Enclosed Bus	No	Metal Enclosed Bus	Consistent with the GALL Report
Metal enclosed bus—enclosure assemblies (3.6.1.9)	Loss of material due to general corrosion	Structures Monitoring Program or Metal Enclosed Bus Program	No	Metal Enclosed Bus	Consistent with the GALL Report
Metal enclosed bus—enclosure assemblies (3.6.1.10)	Hardening and loss of strength due to elastomer degradation	Structures Monitoring Program or Metal Enclosed Bus Program	No	Metal Enclosed Bus	Consistent with the GALL Report
High-voltage insulators (3.6.1.11)	Degradation of insulation quality due to presence of any salt deposits and surface contamination; loss of material caused by mechanical wear due to wind blowing on transmission conductors	A plant-specific AMP is to be evaluated.	Yes	None	Not applicable to STP (see SER Section 3.6.2.2.2)

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
Transmission conductors and connections, Switchyard bus and connections (3.6.1.12)	Loss of material due to wind-induced abrasion and fatigue; loss of conductor strength due to corrosion; increased resistance of connection due to oxidation or loss of preload	A plant-specific AMP is to be evaluated.	Yes	None	Not applicable to STP (see SER Section 3.6.2.2.3)
Cable Connections, metallic parts (3.6.1.13)	Loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	No	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program	Consistent with the GALL Report
Fuse Holders (Not Part of a Larger Assembly) Insulation material (3.6.1.14)	None	None		No AERM or AMP	Not Applicable to STP (see SER Section 3.6.2.1.1)

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. 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. The staff's review of AMPs credited to manage or monitor aging effects of the electrical and I&C components is documented in SER Section 3.0.3

3.6.2.1 AMR Results That Are Consistent with the GALL Report

LRA Section 3.6.2.1 identifies the materials, environments, and aging AERMs, 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 Environmental Qualification Requirements Program
- Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program
- Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program
- Metal Enclosed Bus

- Boric Acid Corrosion Program (for the metallic cable connections exposed to air with borated water leakage)

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 the GALL Report does not recommend further evaluation, the staff's review determined whether the plant-specific components of these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant noted for each AMR item how the information in the tables aligns with the information in the GALL Report. The staff reviewed those AMRs in Table 3.6.2-1 with notes A through E indicating how the AMR is consistent with the GALL Report.

The staff reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did confirm that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMR.

The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's 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. Therefore, the staff concludes that the applicant demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.1.1 AMR Results Identified as Not Applicable

<u>Conductor Insulation for Electrical Cables and Connections Used in Instrumentation Circuits</u>. In LRA Table 3.6.1, item 3.6.1.3, under 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 (IR), the applicant states that all electrical cables and connections used in high-voltage instrumentation circuits that support license renewal intended functions are subject to 10 CFR 50.49 EQ requirements and are managed by the Environmental Qualification (EQ) of Electrical Components Program. GALL Report AMP XI.E2 applies to electrical cables and connections (cable system) used in circuits with sensitive, high-voltage, low-level current signals, such as radiation monitoring and nuclear instrumentation, that are subject to an AMR and installed in adverse localized environments caused by temperature, radiation, or moisture. The applicant stated that electrical cables and connections, which would normally be included in GALL Report AMP XI.E2, are in scope of LRA AMP B3.2, which is consistent with GALL Report AMP X.E1. The staff determines that these component groups do not require an AMR because they are subjected to 10 CFR 50.49 EQ requirements and are managed by the Environmental Qualification (EQ) of Electrical Components Program.

<u>Fuse Holders</u>. In LRA Table 3.6.1, item 3.6.1.6, under fuse holders (not part of a larger assembly) metallic clamp, the applicant states that all fuse holders—including the fuses installed for electrical penetration protection—are part of larger assemblies. Therefore, the applicant concluded that fuse holders with metallic clamps are not subject to an AMR. During the onsite audit, the staff reviewed and discussed electrical distribution system drawings with the

applicant. The staff did not identify any fuse holders within the scope of license renewal that are installed outside an active assembly. Therefore, the staff determined that no AMR is required for fuse holders at STP.

The staff concludes that the applicant demonstrated that the effects of aging for these components will be adequately managed by 10 CFR 50.49 so that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

3.6.2.2.1 Electrical Equipment Subject to Environmental Qualification

LRA Section 3.6.2.2.1 is associated with LRA Table 3.6.1, item 3.6.1.1. SRP-LR Section 3.6.2.2.1 states that EQ is a TLAA to be evaluated in accordance with 10 CFR 54.21(c)(1). The applicant stated that its Environmental Qualification (EQ) of Electrical Components Program meets the requirements of 10 CFR 50.49. The applicant also stated that LRA Section 4.4 describes the 10 CFR 54.21(c)(1) TLAA evaluation of electrical equipment subject to 10 CFR 50.49 EQ requirements. SER Section 4.4 documents the staff's review of the applicant's evaluation of this TLAA and the EQ Electrical Component Program.

3.6.2.2.2 Degradation of Insulator Quality Due to Salt Deposits or Surface Contamination and Loss of Material Due to Mechanical Wear

Summary of Technical Information in the Application. LRA Section 3.6.2.2.2 is associated with LRA Table 3.6.1, item 3.6.1.11, and addresses degradation of insulator quality due to presence of salt deposits, surface contamination, and loss of material due to mechanical wear. SRP-LR Section 3.6.2.2.2 states that, for plants in locations where a potential exists for salt deposits or surface contamination, or mechanical wear caused by wind blowing on transmission conductors, a plant-specific AMP should be evaluated. The applicant stated that STP is located in an area with moderate rainfall and where the outdoor environment is not subject to industry air pollution or salt spray. The applicant also stated that contamination buildup on the high-voltage insulation is not a problem due to sufficient rainfall periodically washing the insulators. Additionally, there is no salt spray at the plant since the plant is not located near the ocean. The applicant then concluded that degradation of insulator quality in the absence of salt deposit and surface contamination is not an AERM.

Regarding loss of material due to mechanical wear, the applicant stated that industry experience has shown that transmission conductors are designed and installed not to swing significantly and cause wear due to wind-induced abrasion and fatigue. The applicant also stated that STP transmission conductors are designed and installed not to swing significantly and cause wear due to wind-induced abrasion and fatigue. The applicant further stated that it has identified no instances of loss of material on high-voltage insulators due to mechanical wear. Therefore, the applicant concluded that loss of material due to wind-induced abrasion and fatigue is not an applicable AERM.

The applicant stated that the STP outdoor environment is not subject to industry air pollution or saline environment. The applicant also stated that STP had experienced several instances of flashover events early in plant life due to lime deposits from heavy dust during construction. The applicant also stated that it has conducted frequent washdowns of insulators to reduce the occurrence of flashover. The applicant further stated that with the application of silicone insulator coatings, the flashover events have been eliminated. The applicant conducts walkdowns to ensure the continuing effectiveness of the silicone coatings.

Staff Evaluation. The staff reviewed LRA Section 3.6.2.2.2 against the further evaluation criteria of SRP-LR Section 3.6.2.2.2, which states that degradation of insulator quality due to salt deposits or surface contamination may occur in high-voltage insulators. The GALL Report recommends further evaluation of plant-specific AMPs for plants at locations of potential salt deposits or surface contamination (e.g., in the vicinity of salt water bodies or industrial pollution). Loss of material due to mechanical wear caused by wind on transmission conductors may occur in high-voltage insulators. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that these aging effects are adequately managed.

The staff noted that STP experienced several instances of flashover events in early plant life due to lime deposits from heavy dust, and that the applicant conducted frequent washdowns of insulators to reduce the occurrence of flashover. The applicant also applied silicone insulator coatings to eliminate the flashover events and conducts walkdowns to ensure the effectiveness of silicone coatings. However, the applicant stated that surface contamination is not an applicable AERM for the insulators at STP. By letter dated September 22, 2011, the staff issued RAI 3.6-1 requesting that the applicant explain why walkdown activities to inspect silicone coatings are not considered aging management of degradation of insulators due to contamination. The staff also requested that the applicant explain why the silicone coating will remain effective for the period of extended operation. The staff also requested that the applicant provide a technical justification of why an AMP for high-voltage insulator is not needed. In its response dated November 21, 2011, the applicant stated that the walkdowns referred to in LRA Section 3.6.2.2.2 are part of the switchyard preventive maintenance activities. Centerpoint Switchyard Maintenance conducts weekly and monthly visual inspections within the switchyard. These walkdowns include visual inspection of the insulators for signs of flaking of the silicone coating. The applicant also stated that the silicone coating applied to the insulators is a consumable that is replaced, as required, based on the results from the preventive maintenance activities. The silicone coating was initially applied during construction to minimize dust buildup and eliminate insulator flashovers. The applicant also stated that with the completion of construction, there has been no occurrence of insulator flashover due to dust. Additionally, the plant is located in an area that receives sufficient rainfall that periodically washes contamination buildup from the insulators. The staff finds the applicant’s response acceptable. Since STP is not located in vicinity of salt water bodies or industrial pollution, surface contamination of high-voltage insulator is not a concern. In addition, the plant is located in an area that received sufficient rainfall that periodically washes away contamination, and the glazed insulator surface also aids this contamination removal. The staff finds the applicant’s response acceptable because the plant-specific operating experience at STP supports the applicant’s conclusion that contamination is not significant at STP and, since the completion of construction, there has been no occurrence of insulator flashover due to dust. The staff’s concern described in RAI 3.6-1 is resolved.

The staff also notes that EPRI 1003057 (License Renewal Handbook) states that mechanical wear in insulators is an aging effect for strain and suspension insulators in that they are subject to movement. Movement of insulators can be caused by wind blowing the supported transmission conductor, causing it to swing from side to side. If this swing is frequent enough, it could cause wear in the metal contact point of the insulator string and between an insulator and supporting hardware. Although this mechanism is possible, industry operating experience has shown that the transmission conductors do not normally swing and that even when they do due to a substantial wind, they do not continue to swing for a long period of time once the wind has subsided. Transmission conductors are designed and installed not to swing significantly and thus avoid mechanical wear due to wind-induced abrasion and fatigue. Transmission conductors within the scope of license renewal are typically short spans (connecting the switchyard to the startup transformers), and the surface area exposed to wind loads are not significant. Furthermore, the applicant did not identify any instances of loss of material on high-voltage insulators due to mechanical wear.

Based on its review, the staff finds that degradation of insulator quality due to presence of salt deposits or surface contamination, and loss of material due to mechanical wear of high-voltage insulators are not aging effects at STP; therefore, the applicant met the further evaluation criteria of SRP-LR Section 3.6.2.2.2.

Conclusion. Based on the programs identified above, the staff concludes that the applicant met the further evaluation criteria of SRP-LR Section 3.6.2.2.2. For those items that apply to LRA Section 3.6.2.2.2, the staff determines that the LRA is consistent with the GALL Report and that the applicant 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).

3.6.2.2.3 Loss of Material Due to Wind-Induced Abrasion and Fatigue, Loss of Conductor Strength Due to Corrosion, and Increased Resistance of Connection Due to Oxidation or Loss of Preload

Summary of Technical Information in the Application. LRA Section 3.6.2.2.3 is associated with LRA Table 3.6.1, item 3.6.1.12, addressing loss of material due to wind-induced abrasion and fatigue, loss of conductor strength due to corrosion, and increased resistance of connections due to oxidation or loss of preload of transmission conductors and connections and switchyard bus and connections. SRP-LR Section 3.6.2.2.2 recommends evaluation of a plant-specific AMP to manage this aging effect. The applicant stated that industry experience has shown that transmission conductors are designed and installed not to swing significantly and cause wear due to wind-induced abrasion and fatigue. Therefore, the applicant concluded that loss of material due to wind-induced abrasion, and fatigue is not an applicable AERM for the period of extended operation.

The applicant also stated that the most prevalent mechanism contributing to loss of conductor strength is corrosion. Corrosion rates depend largely on air quality, which involves suspended particles in the air, SO_2 concentration, rain, fog chemistry, and other weather conditions. The applicant stated that the STP environment is not subject to industrial or salt pollution. UFSAR Section 2.3.2.2.2 shows that there is a low frequency and duration (120 hours per year) of fog at the STP site.

The applicant stated that *IEEE* [Institute of Electrical and Electronics Engineers]*Transactions on Power Delivery* contains a two-part paper on aged aluminum core, steel reinforced (ACSR) conductors, commonly referred to as the Ontario Hydro Study. In testing (Part I), the study found that even with heavy contamination, the aluminum wires were in good condition. Part II of the Ontario Hydro Study concentrates on prediction of remaining life of ACSR cable. The applicant further stated that laboratory testing consistently showed that, for ACSR cable, aluminum was found to have retained its original properties, for the most part, while the steel components showed reductions in tensile strength. The study also indicates that the reduction in strength was almost solely in the steel wires. The study concludes that, for ACSR cable, a mean useful life of 70 years is valid. The applicant also stated that all aluminum conductors (AAC) at STP are not subject to either severe corrosion or reduction in tensile strength due to aging. Therefore, corrosion is not a credible AERM for the period of extended operation.

The applicant stated that the STP outdoor environment is not subject to industry air pollution or saline environment. Aluminum bus material, galvanized steel support hardware, and aluminum connection material do not experience any appreciable aging effects in this environment. The applicant also stated that transmission conductor and switchyard bus connections, at the time of installation, are treated with corrosion inhibitors to avoid connection oxidation and torqued to avoid loss of preload. The applicant further stated that, based on temperature data in the UFSAR Table 2.3-21, the transmission connections and switchyard bus do not experience thermal cycling. The transmission connections and switchyard bus are subject to average monthly temperatures ranging from approximately 27 °C (81 °F) in July to approximately 12 °C (53 °F) in January with minimal ohmic heating. Therefore, the applicant concluded that increased resistance of connections due to thermal cycling is not an AERM for the period of extended operation.

The applicant stated that connection configuration includes stainless steel Belleville washers that are torqued to preclude loss of preload. These connections are periodically evaluated via thermography as part of the preventive maintenance activities. The periodic thermography will continue into the period of extended operation. Therefore, the applicant concluded that increased resistance of connections due to oxidation or loss of preload is not an AERM for the period of extended operation.

<u>Staff Evaluation</u>. The staff reviewed LRA Section 3.6.2.2.3 against the criteria in SRP-LR Section 3.6.2.2.3, which state that loss of material due to wind-induced abrasion and fatigue, loss of conductor strength due to corrosion, and increased resistance of connection due to oxidation or loss of preload could occur in transmission conductors and connections and in switchyard bus and connections. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that this aging effect is adequately managed.

The staff noted that the applicant’s switchyard buses are connected to flexible conductors that do not swing and are supported by insulators and structural supports such as concrete footings and structural steel. Since there are no connections to moving or vibrating equipment, wind-induced abrasion and fatigue would not be an applicable aging mechanism for the applicant’s switchyard bus and connections.

The staff noted that wind-borne particulates have not been shown to be a contributor to loss of material at STP, and wind fatigue is addressed in SER Section 3.6.2.2.2. Therefore, the staff finds the applicant’s determination acceptable that wind-induced abrasion and fatigue is not a significant AERM for transmission conductors and connections at STP.

The staff noted that the design of switchyard bolted connections precludes torque relaxation. The use of stainless steel Belleville washers is the industry standard to preclude torque relaxation. STP design incorporates the use of stainless steel Belleville washers on bolted electrical connections to compensate for temperature changes, maintain the proper torque, and prevent loosening. This method of assembly is consistent with the good bolting practices recommended by industry guidelines (EPRI TR-104213, “Bolted Joint Maintenance & Application Guide”). Based on the review, the staff finds that loosening of the switchyard bolted connections is not an AERM at STP.

The bolted connections and washers are coated with an antioxidant compound (electrical joint compound) prior to tightening the connection to prevent the formation of oxides on the metal surface and to prevent moisture from entering the connection, thus reducing the chances of corrosion. These connections are periodically evaluated via thermography as part of the preventive maintenance activities. The periodic thermography will continue into the period of extended operation. The staff finds that increased resistance of connection due to oxidation or loss of preload are not significant AERMs for transmission conductor and switchyard bus connections.

The staff noted that the transmission conductors at STP are AAC. These transmission conductors, as well as aluminum conductor alloy reinforced (ACAR) conductors, are more resistant to corrosion and loss of conductor strength than the ACSR conductors because they do not contain reinforced galvanized steel, which is prone to corrosion. The GALL Report (NUREG-1801, Revision 2), item VI.A.LP-46, states loss of conductor strength due to corrosion for ACAR (as well as AAC) exposed to air-outdoor environments is not expected and that no AMP is recommended for this component group in the air outside environment. Therefore, the staff determined that loss of conductor strength due to corrosion is not an AERM for AAC transmission conductors at STP.

Based on its review, the staff finds that the aging effects identified in SRP-LR Section 3.6.2.2.3 (loss of material due to wind-induced abrasion and fatigue, loss of conductor strength due to corrosion, and increased connection resistance due to oxidation or loss of preload of transmission conductors and connections and switchyard bus and connections) are not applicable at STP; therefore, the applicant met the further evaluation criteria of SRP-LR Section 3.6.2.2.3.

Conclusion. Based on the programs identified above, the staff concludes that the applicant meets the further evaluation criteria of SRP-LR Section 3.6.2.2.3. For those items that apply to LRA Section 3.6.2.2.3, the staff determines that the LRA is consistent with the GALL Report and that the applicant 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).

3.6.3 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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.7 Conclusion for Aging Management Review Results

The staff reviewed the information in LRA Section 3, “Aging Management Review Results,” and Appendix B, “Aging Management Programs.” On the basis of its review of the AMR results and AMPs, the staff concludes that, with the exception of OI 3.0.3.3.3-2, 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).

With regard to these matters, except for OI 3.0.3.3.3-2, the staff concludes that there is reasonable assurance that the applicant will continue to conduct the activities authorized by the renewed license in accordance with the CLB, and that any changes made to the CLB, in order to comply with 10 CFR 54.21(a)(3), are in accordance with the Atomic Energy Act of 1954, as amended, and NRC regulations.