Safety Evaluation Report

With Open Items 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

February 2013

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 gross electrical output of approximately 1,350 MWe (1,250 MWe net) each. The updated final safety analysis report (UFSAR) contains details of the plant and the site.

Unless otherwise indicated, this SER with open items presents the status of the staff’s review of information submitted through December 14, 2012, the cutoff date for consideration in this SER. The staff has identified four open items (see SER Section 1.5); these items must be closed before a final determination can be made by the staff.

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ABBREVIATIONS

AAC	all aluminum conductors
AC	alternating current
ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards
ACT	analysis confirmatory test
ADAMS	Agencywide Document Access 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
AMP	aging management program
AMR	aging management review
ANS	American Nuclear Society
ANSI	American National Standards Institute
APSCB	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
BMI	bottom-mounted instrumentation
BOP	balance of plant
BTP	branch technical position
BWR	boiling-water reactor
C	Celsius
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
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
DBE	design basis event
DGB	diesel generator building
E	energy
EAB	electrical auxiliary building
EAF	environmentally-assisted fatigue
ECCS	essential core cooling system
ECP	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
EPRI	Electric Power Research Institute
EQ	environmental qualification
ERFDADS	Emergency Response Facilities Data Acquisition and Display System
ESF	engineered safety feature
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
ft	foot
ft-lb	foot-pound (energy)
FWIV	feedwater isolation valve
FWST	firewater storage tank

GALL	Generic Aging Lessons Learned
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
HSS	High Safety Significance
HVAC	heating, ventilation, and air conditioning
I&C	instrumentation and control
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.	inch
in^2	square inch
IPA	integrated plant assessment
IR	insulation resistance
ISA	independent safety analysis
ISG	interim staff guidance
ISI	inservice inspection
ksi	kips per square inch
kV	kilovolt
lb	pound
LBB	leak-before-break
LER	licensee event report
LOCA	loss-of-coolant accident
LRA	license renewal application
LSS	low safety significance
LTOP	low temperature overpressure protection
LTW	long-term weighting
LWR	light-water reactor
M	margin term
MAB	mechanical auxiliary building
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 electric
MWt	megawatt 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
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	pressure 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
RFO	refueling outage
RG	regulatory guide
RHR	residual heat removal
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
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
S_m	design stress intensity
SRP-LR	standard review plan-license renewal (NUREG-1800)
SSC	structures, systems, and components
SSER	Supplemental Safety Evaluation Report
STP	South Texas Project
STPNOC	South Texas Project Nuclear Operating Company
STW	short-term weighting
SWOL	structural weld overlay
TGB	turbine generator building
TLAA	time-limited aging analysis
TS	technical specifications
TSC	technical service center
TSP	tri-sodium 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
vs.	versus
WCAP	Westinghouse Commercial Atomic Power
wt-%	weight percent

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 the STP license renewal review is John Daily. Mr. Daily can be contacted by telephone at 301-415-3873 or by email at John.Daily@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, D.C. 20555-0001
Attention: John Daily, 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 gross electrical output of approximately 1,350 MWe (1,250 MWe net) 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 technical review of safety issues 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 December 14, 2012. 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 showing the applicant's commitments for renewal of the operating licenses. SER Appendix B is a chronology of the principal correspondence between the staff and the applicant regarding the LRA review. SER Appendix C is a list of principal contributors to the SER, and Appendix D is a bibliography of the references in support of the staff's review.

In accordance with 10 CFR Part 51, and as part of the environmental review, the staff is also preparing a draft plant-specific supplement to NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS)." Issued separately from this SER, this supplement will discuss 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 and implement a comprehensive program plan for nuclear plant aging research. From the results of the nuclear plant aging 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 the initial license, and that the scope of the review did not allow sufficient credit for management programs, particularly the implementation of 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” which regulates management of plant-aging phenomena. As a result of this finding, the staff amended 10 CFR Part 54 in 1995. Published on May 8, 1995, in 60 FR 22461, the amended 10 CFR Part 54 establishes a regulatory process that is more stable and predictable than the previous 10 CFR Part 54. In particular, as amended, 10 CFR Part 54 focuses on the management of adverse aging effects rather than on the identification of age-related degradation unique to license renewal. The staff made these rule changes to ensure that important systems, structures, and components (SSCs) will continue to perform their intended functions during the period of extended operation. In addition, the amended 10 CFR Part 54 clarifies and simplifies the integrated plant assessment process to be consistent with the revised focus on passive, long-lived structures and components (SCs).

Concurrent with these initiatives, the staff pursued a separate rulemaking effort (61 FR 28467), dated June 5, 1996, and amended 10 CFR Part 51 to focus the scope of the review of environmental impacts of license renewal in order to fulfill NRC responsibilities under the National Environmental Policy Act of 1969 (NEPA).

1.2.1 Safety Review

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

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

In implementing these two principles, 10 CFR 54.4 defines the scope of license renewal as including SSCs that are safety-related; whose failure could affect safety-related functions; and 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). SCs subject to an AMR are those that perform an intended function without moving parts or without a change in configuration or properties (i.e., are “passive”) and are not subject to replacement based on a qualified life or specified time period (i.e., are “long-lived”). As required by 10 CFR 54.21(a), an applicant for a renewed license must demonstrate that aging effects will be managed in such a way that the intended 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, detrimental aging effects that may affect active equipment are readily detectable and can be identified and corrected through routine surveillance, performance monitoring, and maintenance. Surveillance and maintenance programs for active equipment, as well as other maintenance aspects of plant design and licensing basis, are required throughout the period of extended operation.

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

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

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

In its LRA, the applicant stated that it used the process described in NEI 95-10, Revision 6 (issued June 2005), NUREG-1800, "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants" Revision 1, dated September 2005, and NUREG-1801, "Generic Aging Lessons Learned (GALL) Report" (Revision 1, dated September 2005). The GALL Report provides a summary of staff-approved aging management programs (AMPs) for the aging of many SCs subject to an AMR. An applicant's willingness to commit to 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 staff reviewers to quickly 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. The revisions to these two documents were issued in December 2010. As described, 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 administratively formatted to align with the LRA, using the numbering sequences of the SRP-LR and the GALL Report, Revision 1 (such as the numbering of AMR items and so on), the staff reviewed LRA content using the guidance in Revision 2 of the SRP-LR and the GALL Report. In places where LRA details differed from Revision 2 of these two documents, the staff issued RAIs to complete its evaluation.

1.2.2 Environmental Review

In December 1996, the staff revised the environmental protection regulations to facilitate the environmental review for license renewal. The staff prepared a "Generic Environmental Impact

Statement (GEIS) for License Renewal of Nuclear Plants" (NUREG-1437, Revision 1) to document its evaluation of the possible environmental impacts associated with renewing licenses of nuclear power plants. For certain types of environmental impacts, the GEIS establishes generic findings applicable to all nuclear power plants. These generic findings are codified in Appendix B to Subpart A of 10 CFR Part 51. Pursuant to 10 CFR 51.53(c)(3)(i), an applicant for license renewal may incorporate these generic findings in its environmental report. In accordance with 10 CFR 51.53(c)(3)(ii), an environmental report must also include analyses of environmental impacts that must be evaluated on a plant-specific basis (i.e., Category 2 issues).

In accordance with NEPA and the requirements of 10 CFR Part 51, the staff performed a plant-specific review of the environmental impacts of license renewal, including whether or not the GEIS had considered new and significant information. 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 staff plans to issue the draft site-specific GEIS supplement and, after receipt and resolution of public comments, the final site-specific GEIS supplement.

1.3 Principal Review Matters

The requirements for renewing operating licenses for nuclear power plants are described in 10 CFR Part 54. The staff performed its technical review of the 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.

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 LRA Section 1, the staff identified an area in which additional information was necessary to complete its evaluation. The staff noted that Section 103d of the AEA, 10 CFR 54.17(b), and 10 CFR 50.38 state, in part, 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 [is] ineligible to apply for and obtain a [renewed] license."

The staff noted that LRA Section 1.1.4 lists a non-U.S. citizen, Mr. Mauricio Gutierrez, as the Executive Vice President and Chief Operating Officer of NRG Energy, Inc. (NRG), and as the Vice President of Texas Genco GP, LLC. The application also states that Mr. Gutierrez is a citizen of Mexico. The staff also noted that NRG is the ultimate parent corporation and owner of subsidiaries Texas Genco GP, LLC, NRG South Texas, LP, and STPNOC. Furthermore, the staff noted that the LRA lists NRG South Texas, LP, and STPNOC among the "applicant and co-owners" for STP, Units 1 and 2, and LRA Section 1.1.4 states that Texas Genco GP, LLC, is "the sole general partner of NRG South Texas LP… [which] holds the actual interest in the South Texas Project." The LRA also states that "[t]he officers and managers of Texas Genco GP, LLC, act for NRG South Texas LP." It was not clear to the staff if the applicant could fully meet the requirements regarding foreign control or influence over activities authorized by the renewed license.

Prior to acceptance of the LRA for docketing, by letter dated December 15, 2010, the staff issued RAI 1.1.4-1, requesting that the applicant describe how STP plans to mitigate foreign control or domination over activities licensed by the NRC, including, but not limited to, matters relating to nuclear safety and security and responsibility for special nuclear material to determine if the aforementioned statute and regulatory requirements have been met. The staff requested that the applicant also respond to the following:

- list any non-U.S. citizens who are members of its boards
- explain whether any foreign person has power (whether direct or indirect) to control election, appointment, or tenure of STPNOC's governing board
- explain 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
- explain whether STPNOC has any contracts, agreements, or arrangements with a foreign person or persons
- explain 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 that STPNOC is a Texas corporation, it is not for profit, it has no members other than its Board of Directors, and the Board of Directors 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, and the three directors elect the fourth director of STPNOC, who then also serves as Chief Executive Officer (CEO) of STPNOC. 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. The applicant also stated that, 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:

> 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. The applicant stated that as 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. Further, 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."

Based on its review of the information provided by the applicant in its response to RAI 1.1.4-1, the staff finds that the applicant provided sufficient detail to allow docketing of the application and commencement of its review. The docketing concerns of RAI 1.1.4-1 are resolved.

Subsequent to acceptance of the LRA for docketing, the staff noted that NRG has multiple joint ventures and agreements with foreign entities, including a joint venture with Toshiba Power 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. Because NRG, through its 44 percent ownership interest in the licensed facility (STP, Units 1 and 2), is the beneficiary of decommissioning trusts that have been established to provide funding for radiological decontamination and decommissioning of STP, Units 1 and 2, involvement of non-U.S. citizens in the management and oversight of the nuclear decommissioning trust funds must be negated.

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 address the following issues concerning foreign ownership or control:

- 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., are 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 also 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. None of NRG's shareholders has any right to participate in decisions concerning nuclear safety or security; has any ability to obtain control or responsibility for special nuclear material; or has any way of gaining 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.

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.

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. The applicant provided the "Charter of the Nuclear Oversight Committee of the Board of Directors of NRG Energy, Inc.," in Attachment 1, and a copy of the delegation of actions to the Nuclear Oversight Subcommittee within Attachment 2 of the May 31, 2012, submittal. Specifically, as described in the charter for the NOC, the duties and responsibilities of the NOC include, but are not limited to, the following:

> [t]he Committee [NOC] shall have sole discretion and decision-making authority on behalf of the Company [NRG] as to all matters involving Safety Issues with respect to its ownership interest in STP, STPNOC, and any other nuclear power plant facilities in which NRG may hold any interests. Any powers that the Board generally might otherwise have with respect to matters involving Safety Issues are, except as otherwise expressly provided in this charter, permanently and irrevocably delegated to the Committee [NOC]. For purposes hereof, Safety Issues are matters, which concern any of the following:
>
> (i) Implementation or compliance with any Generic Letter, Bulletin, Order, Confirmatory Order or similar requirement issued by the NRC;
>
> (ii) Prevention or mitigation of a nuclear event or incident or the unauthorized release of radioactive material;
>
> (iii) Placement of a nuclear power plant in a safe condition following any nuclear event or incident;
>
> (iv) Compliance with the Atomic Energy Act of 1954, as amended, the Energy Reorganization Act, or any NRC rule;
>
> (v) Compliance with a specified NRC license and its technical specifications; and
>
> (vi) Compliance with a specific Updated Final Safety Analysis Report, or other licensing basis document.

The charter also states that the full NRG Board shall have, after consultation with the NOC, certain rights, which include:

- the right to vote as to whether or not to close a facility and begin decommissioning, and as to whether to seek relicensing
- the right to decide to sell, lease, or otherwise dispose of NRG's interest in a nuclear power plant facility

- the right to take any action that is ordered by the NRC or any other agency or court of competent jurisdiction

STPNOC is subject to U.S. control, and it will exercise authority over nuclear safety and security matters free from any potential for foreign domination or control over its decision making in any area of concern to the NRC 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.

The applicant stated that its responses demonstrate that there is no potential for foreign ownership, control, or domination (FOCD) to be exercised over the STP, Units 1 and 2, licenses. The staff notes that its FOCD determination is based on the totality of facts since a foreign entity may exert indirect control through factors other than ownership and voting interests, including, but not limited to, financial matters.

The staff believes that the above facts are consistent with making a finding of acceptability with respect to protecting the common defense and security of the U.S. Such facts, though not a total resolution of the prohibition of FOCD under Section 103 of the AEA, are consistent with a favorable determination under that section because of previous Commission statements that the foreign control limitation should be given an orientation toward safeguarding the national defense and security. However, based on the applicant's responses to RAI 1.1.4-1 and RAI 1.1.4-2, as described above, and on the staff's review of all the facts and circumstances, the staff has also determined that a license condition is necessary to ensure compliance with the requirements of 10 CFR 54.17(b) and 10 CFR 50.38. The license condition will specify the following:

- NRG will maintain the NRC-approved NOC and Nuclear Oversight Subcommittee, which are made up of U.S. citizens, to ensure that they have sole discretion and decision-making authority on behalf of NRG as to all matters involving safety and security with respect to its ownership interest in STP, STPNOC, and any other nuclear power plant facilities in which NRG may hold any interests. The NOC and the Nuclear Oversight Subcommittee shall not be changed, amended, or repealed in any respect without the prior written consent of the Director, Office of Nuclear Reactor Regulation.
- The President and CEO of NRG must be U.S. citizens, and they will have authority on behalf of NRG to take all actions with respect to NRG's ownership interest in STP,

Units 1 and 2, regarding safety, security, or ordinary course of business and operations of STP, Units 1 and 2.

- The applicant shall notify the Director, Office of Nuclear Reactor Regulation, promptly of any filing with the SEC, of any Schedules 13D or 13G filed pursuant to the Securities and Exchange Act of 1934, which disclose beneficial ownership of any registered class of NRG stock.

The staff finds that the above facts, with the addition of the conditions of the renewed Facility Operating License, are consistent with making a finding of acceptability with respect to protecting the common defense and security of the U.S. In light of the proposed license condition, the staff does not know or have reason to believe that the subject licenses will be owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government; therefore, Section 103d of the Act is satisfied in that regard.

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 number upon issuance of the renewed license, if approved. Therefore, conforming changes to the indemnity agreement need not be made, and the 10 CFR 54.19(b) requirements have been met.

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

- an integrated plant assessment
- a description of any CLB changes during the staff’s review of the LRA
- an evaluation of TLAAs
- 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 has submitted one annual update, by letter dated November 30, 2011, to summarize the CLB changes that occurred since submittal of the LRA through the update's issue date. The applicant stated that the submission was in accordance with 10 CFR 54.21(b) requirements and that it described the changes affecting the STP LRA.

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 identified Appendix D for satisfying the requirements of 10 CFR 54.22, and stated that "[s]ince no Technical Specification changes are requested, this Appendix is not used."

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

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

1.4 Interim Staff Guidance

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

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

ISG Issue (Approved ISG Number)	Purpose	SER Section
"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 buried and underground piping and tanks.	SER Section 3.0.3.2.14
"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

1.5 Summary of Open Items

As a result of its review of the LRA, including additional information submitted through December 14, 2012, the staff identified four Open Items (OIs). 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 each of the OIs is as follows:

OI 3.0.3.3.3-1: Insufficient details provided regarding applicant's Selective Leaching of Aluminum Bronze Aging Management Program (AMP). The staff lacks sufficient information to complete its evaluation of the Selective Leaching of Aluminum Bronze Program. The following issues were identified:

- The staff requested a list of the number of remaining susceptible components, broken down by size.
- The AMP, UFSAR Supplement, and Commitments do not contain an adequate number of continuing confirmation profile examinations (PEs) and analysis confirmation tests (ACTs) to be conducted after issuance of the renewed license.
- The descriptions of PEs and ACTs are not clear in the AMP, UFSAR Supplement, and Commitments, and as such, testing and inspection requirements may not be correctly interpreted in the future.
- The program is not clear on how partially-dealloyed material property results will be integrated into trending data, or how the percentage dealloying will be determined from a dimensional and chemical composition basis, for testing being conducting in the future.
- The program does not state or justify the minimum level of degradation that a component must exhibit in order to be used as an appropriate test specimen for ACTs.
- The program is not clear on how the internal flaw size is determined from the outside diameter visual inspection results, nor is it clear why an average through-wall dealloying angle is used in the structural integrity analyses rather than the full inside-wall dimension of the degraded area.
- The program is not clear on how structural (safety) factors are incorporated into the structural integrity analyses.

- The program lacks sufficient specificity for the staff to determine follow-on actions that would be taken as a result of six different adverse PE, ACT, or in-situ leakage scenarios, as described in the SER.
- UFSAR Section 9A, “Assessment of the Potential Effects of Through-Wall Cracks in ECWS Piping,” does not include a basis for why one-inch and under lines can be demonstrated to meet their intended function prior to replacement.
- The response for flooding, reduction in flow, and water loss from the essential cooling water pond did not address the basis for why the assumed flaw size was larger than the maximum size flaw that could occur where structural integrity is maintained but leakage occurs nonetheless. The staff requires the results of the leak rate analysis committed to in Commitment No. 46 in order to complete its evaluation of the program.
- Based on the outcome of the staff’s further review of the applicant’s analytical basis for structural integrity of susceptible components, further details may be required in LRA Section A1.37, UFSAR Supplement.

The staff issued RAI B2.1.37-5 by letter dated December 18, 2012, requesting that the applicant address these issues. This is being tracked as OI 3.0.3.3.3-1.

OI 3.0.3.2.6-2: Management of fouling of downstream components due to coating degradations upstream. The staff could not determine whether the inspection method and inspection frequency of internally-applied coatings in the ECW system will appropriately manage aging in locations where coating degradations could cause fouling of downstream components. In addition, since some internal coatings are considered limited-life applications with service lives less than 20 years, the types and frequencies of inspections should be adjusted as the coatings approach their end of life. By letter dated July 12, 2012, the staff issued RAI B2.1.9-3c, requesting that the applicant address these issues. This is being tracked as OI 3.0.3.2.6-2.

OI 3.0.3.1.4-1: Cracking in Unit 1 RWST. The staff noted a report by the applicant of operating experience concerning an active leak due to cracking in the Unit 1 refueling water storage tank (RWST), yet the applicant was not managing cracking of the RWSTs or similar tanks. In 1999, the applicant discovered the crack in the Unit 1 RWST at the top of the shell-to-base-plate weld. In documentation associated with the relief request for this defect, the applicant concluded that the aging mechanism was stress corrosion cracking (SCC), based on evidence of transgranular crack propagation and branching. The staff noted that the 1999 crack was stated to be in a low-stress area and unlikely to grow; however, the staff found no basis to conclude that cracking—particularly SCC—would not occur in higher-stress areas, such as in tank sidewalls. The staff also noted that, in the absence of inspections that can detect SCC for RWSTs and similar stainless steel tanks, there is no basis to conclude that the structural integrity of the tanks will not be challenged during the period of extended operation. By letter dated September 24, 2012, the staff issued RAI B2.1.16-4, requesting that the applicant address this issue. This issue is being tracked as OI 3.0.3.1.4-1.

OI 4.3.2.11-1: Effects of thermal aging on cast austenitic stainless steel (CASS). As part of its evaluation of the thermal embrittlement of CASS material in leak-before-break piping, the staff noted that part of the applicant’s justification relies upon an evaluation and data from 1983. The staff also noted that considerable information has been developed since 1983 to provide improved understanding of the thermal embrittlement of CASS materials. The staff further noted that the applicant’s position—that its material property aging is based on the “minimum material properties possible”—does not provide adequate justification in light of the additional information produced over the last 29 years. Additionally, it does not demonstrate that the aging after 60 years of operation is bounded by the thermal embrittlement saturation values assumed in the applicant's existing analysis. By letter dated November 19, 2012, the staff issued RAI 4.3.2.11-6, requesting that the applicant address this issue. This is being tracked as OI 4.3.2.11-1.

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

As a result of the staff's review of the LRA, including subsequent information and clarifications from the applicant, the staff identified proposed license conditions, which are summarized as follows:

- The first license condition requires the applicant to include the UFSAR supplement required by 10 CFR 54.21(d) in the next UFSAR update, required by 10 CFR 50.71(e), following the issuance of the renewed licenses. The applicant may make changes to the programs and activities described in the UFSAR supplement provided the applicant evaluates such changes in accordance with the criteria set forth in 10 CFR 50.59 and otherwise complies with the requirements in that section.
- The second license condition will state that the applicant's UFSAR supplement describes certain programs to be implemented and activities to be completed prior to the period of extended operation and that the applicant shall implement those new programs and enhancements to existing programs as noted in certain commitments no later than 6 months prior to the period of extended operation. The specific license condition will also state that the applicant shall complete those activities as noted in certain commitments by the 6-month date prior to the period of extended operation or the end of the last refueling outage prior to the period of extended operation, whichever occurs later. Finally, the specific license condition will state that the applicant shall notify the NRC in writing within 30 days of implementing the programs, and include the status of those activities to be completed by the 6-month date prior to the period of extended operation or the end of the last refueling outage prior to the period of extended operation, whichever occurs later.
- The third license condition will specify 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 will also state 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.
- The fourth license condition will specify the measures that must be maintained regarding foreign ownership, control, or domination, pursuant to 10 CFR 54.17(b). The license condition will specify that NRG will maintain the NRC-approved NOC and Nuclear Oversight Subcommittee, both of which are to be made up of all U.S. citizens, and ensure that they have sole discretion and decision-making authority on behalf of NRG as

to all matters involving safety and security with respect to its ownership interest in STP, Units 1 and 2, STPNOC, and any other nuclear power plant facilities in which NRG may hold any interests. The NOC and the Nuclear Oversight Subcommittee shall not be changed, amended, or repealed in any respect without the prior written consent of the Director, Office of Nuclear Reactor Regulation. The license condition will also state that the President and CEO of NRG must be U.S. citizens and will have authority on behalf of NRG to take all actions with respect to NRG's ownership interest in STP, Units 1 and 2, regarding safety, security, or ordinary course business and operations of STP, Units 1 and 2. Finally, the license condition will also state that STPNOC shall notify the Director, Office of Nuclear Reactor Regulation, promptly of any filing with the SEC of any Schedules 13D or 13G, filed pursuant to the Securities and Exchange Act of 1934, that disclose beneficial ownership of any registered class of NRG stock.

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. 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:

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

2.1.2 Summary of Technical Information in the Application

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 sections of the LRA using the guidance contained in the SRP-LR:

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

In addition, the staff conducted a scoping and screening methodology audit at 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 Appendix A, “Final Safety Analysis Report Supplement,” and Appendix B, “Aging Management Programs,” of the LRA. On a sampling basis, the staff performed a system review of the 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 (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 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

<u>Scoping and Screening Implementing Procedures</u>. 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 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 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 determined that the scoping and screening methodology instructions are consistent with the methodology description provided in LRA Section 2.1. The applicant's methodology is sufficiently detailed to provide concise guidance on the scoping and screening implementation process to be followed during the LRA development activities.

<u>Sources of Current Licensing Basis (CLB) Information</u>. Pursuant to 10 CFR 54.21(a)(3), for each structure and component 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), 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 master equipment database, the Q-List (a specific portion of the master equipment database 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 master equipment database, 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 has 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 determined 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 current licensing basis 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. 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 scoping and screening methodology considers CLB information in a manner consistent with the Rule, the SRP-LR, and NEI 95-10 guidance; therefore, it 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. The staff determined 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

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

2.1.3.3 Training

2.1.3.3.1 Staff Evaluation

The staff reviewed the applicant's training 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. The staff determined that the applicant developed and implemented adequate procedures to control the training of personnel performing LRA activities.

2.1.3.3.2 Conclusion

On the basis of discussions with the applicant's license renewal project personnel responsible for the scoping and screening process and its review of selected documentation in support of the process, the staff concludes that applicant's personnel are adequately trained 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

The staff reviewed the information provided in LRA Section 2.1, the applicant's scoping and screening implementing procedures, discussions with the applicant's license renewal personnel, 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. On the basis of this review, 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; therefore, it 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 determined that the applicant’s evaluation of DBEs was consistent with the SRP-LR.

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

The staff reviewed the applicant’s evaluation of the Rule and CLB definitions pertaining to 10 CFR 54.4(a)(1) and 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

On the basis of its review of the scoping process, discussions with the applicant, and review of the information provided in the response to RAI 2.1-1, the staff concludes that the applicant’s methodology for identifying systems and structures is consistent with the SRP-LR and 10 CFR 54.4(a)(1); therefore, it 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, 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 high-energy line breaks (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)

<u>Nonsafety-Related SSCs with the Potential for Spatial Interaction with Safety-Related SSCs</u>. 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 it was in 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

On the basis of its review of the applicant's scoping process, discussions with the applicant, and review of the information provided in the response to RAIs 2.1-2 and 2.1-3, the staff concludes that the applicant's methodology for identifying and including nonsafety-related SSCs, which could affect the performance of safety-related SSCs, within the scope of license renewal, is consistent with the scoping criteria of 10 CFR 54.4(a)(2); therefore, it 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 CFR50.62 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 [station blackout] coping duration, alternate AC [alternating current] power source, condensate inventory for decay heat removal, Class 1E battery capacity, compressed air requirements, effect of loss of ventilation, containment isolation, reactor coolant inventory 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, EQ, ATWS, PTS, and SBO. As part of this review, the staff discussed the applicant’s methodology, 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).

<u>Environmental Qualification</u>. 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).

<u>Pressurized Thermal Shock</u>. 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 and 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).

<u>Anticipated Transient Without Scram</u>. 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).

<u>Station Blackout</u>. The staff determined that the applicant's scoping reports included SSCs determined from the CLB that the applicant identified, which were associated with coping and safe shutdown of the plant following an SBO event by reviewing the SBO topical report that was primarily developed using information from the UFSAR Section 8.3.4 and SBO design basis document. 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

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

On the basis of its review of the LRA, scoping implementing procedures, and the sampling system review of mechanical scoping results, the staff concludes that the applicant's methodology for identifying mechanical SSCs within the scope of license renewal complies with the requirements of 10 CFR 54.4; therefore, it 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

On the basis of its review of information in 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 complies with the requirements of 10 CFR 54.4; therefore, it 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, 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

On the basis of its review of information contained 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; therefore, it is acceptable.

2.1.4.8 Scoping Methodology Conclusion

On the basis of its review of the LRA, implementing procedures, and a sampling review of scoping results, the staff concludes that the applicant's scoping methodology was consistent with the guidance contained in the SRP-LR and identified those SSCs that are within the scope of license renewal in accordance with 10 CFR 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); therefore, it 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 is discussed in SER Sections 2.1.5.2 through 2.1.5.4.

2.1.5.1.3 Conclusion

On the basis of a review of the LRA, the implementing procedures, and a sampling of screening results, the staff concludes that the applicant's screening methodology was consistent with the guidance contained in the SRP-LR and was capable of identifying passive, long-lived components in-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; therefore, it 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

On the basis of its review of the LRA, the screening implementation procedures, selected portions of the UFSAR, plant equipment database, CLB documentation, procedures, drawings, specifications and selected scoping and screening reports, and a sample 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); therefore, it 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 the 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

On the basis of its review of information contained 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); therefore, it 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

On the basis of its review of 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); therefore, it is acceptable.

2.1.5.5 Screening Methodology Conclusion

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

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 has 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 whether the systems and structures have any intended functions requiring their inclusion within the scope of license renewal. The staff’s review of the applicant’s implementation was conducted in accordance with the guidance in SRP-LR Section 2.2, “Plant-Level Scoping Results.”

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 failed to identify any systems and structures within the scope of license renewal. On the basis of its review, the staff concludes that the applicant has appropriately identified the systems and structures within the scope of license renewal in accordance with 10 CFR 54.4.

2.3 Scoping and Screening Results: Mechanical Systems

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

- 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 passive, long-lived SCs 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 the applicant identified the mechanical system SCs that met the scoping criteria and were subject to an AMR, confirming that there were no omissions.

The staff's evaluation of mechanical systems was performed using the evaluation methodology described here and in the guidance 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 has identified, in accordance with 10 CFR 54.4, components and supporting structures for mechanical systems that meet the license renewal scoping criteria. Similarly, the staff evaluated the applicant's screening results to 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 under 10 CFR 54.4(a), the staff confirmed the applicant properly screened out only: (a) SCs that have functions performed with moving parts or a change in configuration or properties; or (b) SCs that are subject to replacement after a qualified life or specified time period, as described in 10 CFR 54.21(a)(1). For SCs not meeting either of these criteria, the staff confirmed the remaining SCs received an AMR, as required by 10 CFR 54.21(a)(1).

The staff evaluation of the mechanical system scoping and screening results applies to all mechanical systems reviewed. Those systems that required RAIs 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 and Internals

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 has 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 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).

2.3.1.2 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 has appropriately identified the RCS 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).

2.3.1.3 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 has appropriately identified the pressurizer 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).

2.3.1.4 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 has 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 has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.1.5 Reactor 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 has 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 has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2 Engineered Safety Features

LRA Section 2.3.2 describes the engineered safety features (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 has 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 has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2.2 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 has 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 has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2.3 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 has 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 has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2.4 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 composed 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)"

<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 were not provided or were incorrect or the continuation drawing was not provided. The applicant was requested to provide additional information to locate the continuations.

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 to locate 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 has 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 has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.2 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 has 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 has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.3 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 applicant was requested to 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 had 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 has 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 composed of three redundant cooling loops, each of which has a pump, a component cooling water (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 applicant was requested to 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 applicant was requested to 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 applicant was requested to 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.

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 had 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 has 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 make-up water system and states that it is composed of a storage tank, two transfer pumps, piping, and valves. The section states that the system’s purpose is to provide reactor grade make-up 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 make-up 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 applicant was requested to 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 under 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 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 not acceptable 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 the applicant to 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 applicant was requested to 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 had 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 has 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) 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 applicant was requested to 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 under 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 under 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 applicant was requested to 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 applicant was requested to 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 revised 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 had 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 has 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-80119F00048#1-1, coordinates G/H-6, 7, and 8, an instrument air compressor (80111MC00014), 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 (80111MC00011, 80111MC00012, and 80111MC00013), 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-80119F00048#2-1. The applicant was requested to 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 under 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-80119F00048#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-80119F00048#1-1 and LR-STP-IA-80119F00048#2-1, coordinates E-5, wet air tanks (80111MTS0161, and 80112MTS0161) 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 (80111MTS0163 and 80112MTS0163 at coordinates E/F-2) on these license renewal boundary drawings show the relief valves as within the scope of license renewal. The applicant was requested to provide the basis for not including the relief valves on wet air tanks 80111MTS0161 and 80112MTS0161 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 80111MTS0161 and 80112MTS0161 were inadvertently omitted and should be within the scope of license renewal for 10 CFR 54.4(a)(3). The applicant revised license renewal boundary drawings, LR-STP-IA-80119F00048#1-1 and LR-STP-IA-80119F00048#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-in. drain piping (1"lA1238UDS 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 applicant was requested to 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. The applicant revised the license renewal drawing to depict the above drain piping excluded from 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 since 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-80119F00048#2-2, coordinates B-6, piping with a capped end, upstream of a 4-in. by 3-in. 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-80119F00048#1-2, coordinates B-6, is shown as not being within the scope of license renewal. The applicant was requested to provide a basis for not including the piping on license renewal drawing LR-STP-IA-80119F00048#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-in. by 3-in. reducer on license renewal drawing LR-STP-IA-80119F00048#1-2 (coordinates B-6) was inadvertently omitted from, and should be within, the scope of license renewal. The applicant revised license renewal drawing LR-STP-IA-80119F00048#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-80119F00048#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 applicant was requested to provide the basis for not including the continuation piping sections within the scope of license renewal.

LRA section/drawing number & location	Continuation piping/drawing number
LR-STP-IA-80119F05050#1 and LR-STP-IA-80119F05050#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-80119F05050#1 and LR-STP-IA-80119F05050#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. 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 had 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 has adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.8 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 applicant was requested to 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 under 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. 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 applicant was requested to 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 due to the piping being located within the primary sample panel. 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 applicant was requested to 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 scope of license renewal on the latter drawings. 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 applicant was requested to 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 noted 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 applicant was requested to 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 noted 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 applicant was requested to 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 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) which contains nonsafety-related attached to safety-related components, yet no apparent seismic anchor is indicated. The applicant was requested to 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 under 10 CFR 54.4(a)(2) for spatial interaction.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.8-7, 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 applicant was requested to 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. 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 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 on license renewal boundary drawings LR-STP-PS-9Z329Z00047#1 and LR-STP-PS-9Z329Z00047#2, coordinate 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 applicant was requested to 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 had 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 has adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.9 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 applicant was requested to 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 applicant was requested to 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 applicant was requested to 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 had 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 has adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.10 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 has 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 has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.11 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 composed 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 has 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 has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.12 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 composed 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 has 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 has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.13 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 has 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 has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.14 Reactor Containment Building HVAC

2.3.3.14.1 Summary of Technical Information in the Application

LRA Section 2.3.3.14 describes the reactor containment building (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 its 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 has appropriately identified the reactor containment building HVAC 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).

2.3.3.15 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 has 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 has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.16 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 design-basis accidents 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 has 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 has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.17 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 composed 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
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 the following:

> BOP transformers 1D1, 1D2, 2D1, and 2D2 are nonsafety and do not perform any license renewal related function. Therefore, these transformers are not within the scope of license renewal. None is located within 50 feet of a safety-related building. 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. The applicant further stated that STPNOC will amend the application to include the lighting diesel generator, the lighting diesel generator fuel supply, the lighting DGB and the fire water suppression system.

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. The applicant stated that LRA drawing LR-STP-FP-7Q272F00046 will be updated to reflect this change.

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.

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

2.3.3.18 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 has 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 has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.19 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 has 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 has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.20 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 composed 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 9.3.1.3.2, 9.5.1.2.1, and 9.5.10, 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 applicant was requested to 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 applicant was requested to 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 applicant was requested to 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 applicant was requested to clarify whether or not there are diesel lube oil reservoir tanks in the system and, if they 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 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-in. 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-in. copper piping attached downstream of the 1-in. stainless steel piping. The staff noted that the ½-in. copper piping is attached to the membrane dryers. The configuration of the ½-in. 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 applicant was requested to 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-in. 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-in. stainless steel piping to $^{1}/_{2}$-in. 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 had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the 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 has adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.21 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 says 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 has 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 has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.22 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 applicant was requested to provide the basis for the change in scoping classification for these piping sections.

LRA section/drawing number and coordinate location	Continuation piping/drawing number
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	1" piping on LR-STP-RC-5R149F05004#1 and

LR-STP-WL-5R309F05022#2 coordinates E-6	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 applicant was requested to 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 pressurizer relief tanks (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 applicant was requested to 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). 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; the corrected drawing now depicts the piping sections and components within the scope of license renewal for 10 CFR 54.4(a)(2). The staff confirmed on the revised license renewal boundary drawing 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 applicant was requested to 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 had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the liquid waste processing system mechanical components within the scope of license renewal, as required by 10 CFR 54.5(a), and that the applicant has adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.23 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 composed 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 applicant was requested to 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-in. 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 applicant was requested to 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 concern 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 had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the 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 has adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.24 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 has 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 has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.25 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 has 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 has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.26 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 applicant was requested to 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 had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the 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 has adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.27 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 has 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 has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4 Steam and Power Conversion Systems

LRA Section 2.3.4 identifies the steam and power conversion systems' SCs subject to an AMR for license renewal. The applicant described the supporting SCs of 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 applicant was requested to 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. The staff confirmed on the revised license renewal boundary drawings 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 applicant was requested to 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 had identified all components within the scope of license renewal. In addition, the staff’s review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the main steam system mechanical components within the scope of license renewal, as required by 10 CFR 54.5(a), and that the applicant has adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.2 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, coordinate G-4, depicts piping 2"WL2586XC7 as being within the scope of license renewal under 10 CFR 54.4(a)(2). The piping continues to LR-STP-WL7R309F05026#2, coordinate E-6, where it is depicted as not within the scope of license renewal. The applicant was requested to 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 had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the auxiliary steam system and boilers mechanical components within the scope of license renewal, as required by 10 CFR 54.5(a), and that the applicant has adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.3 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 had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the feedwater system mechanical components within the scope of license renewal, as required by 10 CFR 54.5(a), and that the applicant has adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.4 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 applicant was requested to 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 which 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 noted that spatial interaction terminates when pipe 4"DW0018WD9 goes underground in the MEAB. The staff also noted 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 had identified all components within the scope of license renewal. In addition, the staff’s review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the demineralized water (makeup) system mechanical components within the scope of license renewal, as required by 10 CFR 54.5(a), and that the applicant has adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.5 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 has 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 has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.6 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-in.

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 applicant was requested to 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-in. vent piping and valves AF0129 and AF0130 were incorrectly depicted on license renewal drawing LR-STP-AF-5S142F00024-1 as being excluded from 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-in. 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. The staff confirmed on the revised license renewal boundary drawings that no additional component types were added as a result of the 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-in. 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 applicant was requested to 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 applicant was requested to 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 had identified all components within the scope of license renewal. In addition, the staff's review determined whether the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes the applicant appropriately identified the AFW system mechanical components within the scope of license renewal, as required by 10 CFR 54.5(a), and that the applicant has adequately identified all the mechanical components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.7 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 has 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 has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4 Scoping and Screening Results: Structures

This section documents the staff's review of the applicant's scoping and screening results for structures 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 under 10 CFR 54.4(a). The staff also reviewed the licensing basis documents to determine whether the LRA specified all intended functions delineated under 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. The 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 under 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."

In reviewing the applicant's response to RAI 2.4.1-1, the staff found 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. Based on its review, 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.”

In reviewing the applicant’s response to RAI 2.4.1-2, the staff found 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. Based on its review, 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 a multistory, structural steel, and reinforced concrete structure that is physically located in the MEAB. 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 under 10 CFR 54.4(a).

The staff then reviewed those SCs that the applicant has included as within the scope of license renewal to 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 the applicant to 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.

In reviewing the applicant's response to RAI 2.4.2-1, the staff found that the applicant 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. Based on its review, 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-in. 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."

In reviewing the applicant's response to RAI 2.4.2-2, the staff found that the applicant adequately clarified the inclusion of the dual 9-in. water stops located in all seismic joints between Category I structures as components within the scope of license renewal and subject to an AMR. Based on its review, 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 under 10 CFR 54.4(a).

The staff then reviewed those SCs that the applicant has included as within the scope of license renewal to 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.

In reviewing the applicant's response to RAI 2.4.3-1, the staff found that the applicant 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. Based on its review, 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 has 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 has 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 multi-story 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 has 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 has 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:

- fire pump house
- fire water storage tanks foundation
- fire water valve structure

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.

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 has 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 has 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 composed 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.

Also, 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.

Finally, 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.

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 has 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 has 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 foundation composed of 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 has 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 has 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 composed 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 under 10 CFR 54.4(a).

The staff then reviewed those SCs that the applicant has included as within the scope of license renewal to 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."

In reviewing the applicant's response to RAI 2.4.9-1, the staff found that the applicant 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. Based on its review, 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 has 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 has 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 has 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 has 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 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 10CFR 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 under 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 under 10 CFR 54.4(a). The staff then reviewed those components that the applicant has identified as within the scope of license renewal to 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, issued by letter 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 reiterated that its position, as indicated in SRP-LR Section 2.5.1.1, was that irrespective of whether SBO recovery path breakers are closed manually or remotely, control circuits associated with those breakers 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 Section 2.5 of the LRA 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 the Sections 2.3.3 and 2.3.4 of the LRA. The staff reviewed and confirmed that resistance temperature detectors, sensors, thermocouples, and transducers with an intended function of pressure boundary are included in the AMR lists in Section 2.3.3 and 2.3.4 of the LRA. Based on its review, 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 has adequately identified those SSCs that are within the scope of license renewal, as required by 10 CFR 54.4(a), and those SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1).

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) (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).

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," 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 quickly identify those AMPs and activities that the staff has determined will adequately manage or monitor aging during the period of extended operation.

The GALL Report identifies the following:

- systems, structures, 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, such as AMR items and so on, 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 responses are documented in applicable portions of Section 3 of this SER.

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 Document 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 STP 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 as being portions of the GALL Report AMP that the applicant does not intend to implement.

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

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 the claim. For each AMP with one or more deviations, the staff evaluated each deviation to determine if the deviation was acceptable and if the modified AMP would adequately manage the aging effect(s) for which it was credited. For AMPs not evaluated in the GALL Report, the staff performed a full review to determine 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 or not the AMRs identified by the applicant align with the GALL Report AMRs. For a given AMR in a Table 2, the staff reviewed the intended function, material, environment, AERM, and AMP combination for a particular system component type. Item numbers in column 7 of the LRA, "NUREG-1801 Volume 2 Item," correlate to an AMR combination as identified in the GALL Report. The staff also conducted onsite audits to 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 eight, "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 of "air-indoor controlled," "air-indoor uncontrolled," "condensation," "air, moist," "air with steam or water leakage," etc., 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 3.3.2-17 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 where 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 has 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

SER 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 claimed consistency, and the section of this SER 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	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 Exception	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 Enhancement	XI.M18, "Bolting Integrity"	3.0.3.2.5
Steam Generator Tube Integrity	B2.1.8, A1.8	Existing	Consistent with the GALL Report	XI.M19, "Steam Generator Tube Integrity"	3.0.3.1.3

Applicant AMP	LRA Sections	New or Existing Program	Applicant Comparison to the GALL Report	GALL Report AMP	SER Section
Open-Cycle Cooling Water System	B2.1.9, A1.9	Existing	Consistent with the GALL Report, with Exception and Enhancement	XI.M20, "Open-Cycle Cooling Water System"	3.0.3.2.6
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	XI.M36, "External Surfaces Monitoring Program"	3.0.3.2.16

Applicant AMP	LRA Sections	New or Existing Program	Applicant Comparison to the GALL Report	GALL Report AMP	SER Section
Flux Thimble Tube Inspection	B2.1.21, A1.21	Existing	Consistent with the GALL Report, with Enhancements	XI.M37, “Flux Thimble Tube Inspection”	3.0.3.2.17
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”	3.0.3.1.7
ASME Code Section XI, Subsection IWE	B2.1.27, A1.27	Existing	Consistent with the GALL Report, with Exceptions	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 Enhancement	XI.S4, “10 CFR Part 50 Appendix J”	3.0.3.2.25

Applicant AMP	LRA Sections	New or Existing Program	Applicant Comparison to the GALL Report	GALL Report AMP	SER Section
Masonry Wall Program	B2.1.31, A1.31	Existing	Consistent with the GALL Report	XI.S5, “Masonry Wall Program”	3.0.3.1.6
Structures Monitoring Program	B2.1.32, A1.32	Existing	Consistent with the GALL Report, with Enhancements	XI.S6, “Structures Monitoring Program”	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 Enhancement	XI.S7, “RG 1.127 Inspection of Water Control Structures 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”	3.0.3.1.8
Concrete Containment Tendon Prestress	B3.3, A2.3	Existing	Consistent with the GALL Report	X.S1, “Concrete Containment Tendon Prestress”	3.0.3.1.9
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:

- 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

- Masonry Wall Program
- 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 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.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 or not 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 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 that the program was credited for. 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 has 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 A1.1 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 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 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.2 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 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 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 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-03-0039, 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 this order has been superseded by ASME Code Case N-729-1 as discussed above, and that the applicant stated in its LRA that it has revised its existing inservice inspection program to meet ASME Code Case N-729-1, subject to the conditions 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 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 has 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 no reason to believe 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 not 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 has 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.3 Steam Generator Tube Integrity

Summary of Technical Information in the Application. LRA Section B2.1.8 describes the existing Steam Generator Tube Integrity Program as consistent with the GALL Report AMP XI.M19, "Steam Generator Tube Integrity." The applicant stated that the program manages the loss of material of the following component types: 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. It was 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 steam generator non-destructive 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 dated March 8, 2012, the applicant clarified that the secondary side access covers and secondary nozzles are included in the AMP since they are components internal to the SGs; therefore, they are 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.

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.M19.

For the "detection of aging effects" 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.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.

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.

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.

Based on its audit and review of the applicant's Steam Generator Tube Integrity Program, and review of the applicant's response to RAI B2.1.8-1, 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.M19.

<u>Operating Experience</u>. 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 non-destructive 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 to the NRC following an outage where an inspection was performed in accordance with TS 6.8.3.o. The applicant's inspection reports following the 1RE13 RFO (October 2006) and 1RE14 RFO (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; since 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 towards 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 since 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 has 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 A1.8 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. 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 Steam Generator Tube Integrity 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.4 One-Time Inspection

Summary of Technical Information in the Application. 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 is resolved.

Based on its audit, 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 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 in a response dated August 18, 2011, Amendment 3, it 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 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 associated 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 September 24, 2012, the staff issued RAI B2.1.16-4, 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. Pending the staff's review of the applicant's response, this issue is identified as Open Item (OI) 3.0.3.1.4-1.

Based on its audit, review of the application, and review of the applicant's response to RAI B2.1.16-1, the staff finds, with the exception of OI-3.0.3.1.4-1, that the applicant has 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 NDE 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 Corrective Action Program 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.

The staff finds that the information in the UFSAR supplement, as amended by letter dated September 15, 2011, 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, with the exception of the "operating experience" program element and its associated OI 3.0.3.1.4-1. The staff concludes that, with the exception of OI 3.0.3.1.4-1, the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.5 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 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 Propolene 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 localize 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 STP 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 has 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.6 Masonry Wall Program

Summary of Technical Information in the Application. LRA Section B2.1.31 describes the existing Masonry Wall Program as consistent 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," and Information Notice (IN) 87-67, "Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11." 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 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 has 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 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 has 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 implement 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.7 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 License Renewal Interim Staff Guidance (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 in 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 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 due to 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 has 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.8 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 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 re-calculated 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 re-calculated, 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 which 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 has 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.9 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 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 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 which needed 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 structural integrity test 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 liftoff 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 liftoff 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 re-fill the voids with grease. The staff finds this response acceptable because corrective actions were taken in response to the discovery of deficient conditions with regards 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 has 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 A2.3 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.

Conclusion. 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 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 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

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 steam generator secondary side, and the secondary cycle systems to manage the aging effects associated with corrosion mechanisms and stress corrosion cracking (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 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 has 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 A1.2 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.

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 its implementation—through Commitment No. 1, of LRA Table A4-1—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).

3.0.3.2.2 Reactor Head Closure Studs

Summary of Technical Information in the Application. LRA Section B2.1.3 describes the existing Reactor Head Closure Studs Program as consistent, with exceptions, 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 reactor vessel (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, "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 or not 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 program scope, 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 program scope.

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.

In 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.

In 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."

In its review regarding the ASME Code Cases approved by the NRC, 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. In 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 on site 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), 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.

In its review, 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 B2.1.3-1b, 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 2.1.3-1b 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.

<u>Operating Experience</u>. 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.

In 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.

In its review, 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.

In its review 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 due to 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 or not 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 or not 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 or not 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 due to 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 to 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.

In 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 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 (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.

In its review, the staff finds 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 finds 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 still 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.

In its response 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.

In 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 to further clarify whether or not the applicant has performed inspections to monitor any additional adverse change in the load-bearing areas of the damaged stud insert. The staff also needed to clarify whether or not 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). RAI B2.1.3-2a, which was issued to resolve this concern, is described below in more detail.

In 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). In its review, 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 found a need to further 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 or not any other stud or stud insert has experienced damage similar to that of the partially rolled stud insert
- provide information to confirm whether or not 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 or not 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 further communicated with the applicant about the implementation schedule by issuing 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 will 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 since 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, since 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 28, 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 in. 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 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

In 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, according to 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 350 °F, which is the stud insert temperature at the end of the heatup according to 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 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 response regarding the AMP is acceptable, as 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 that it is not enough to cause a significant 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 has 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 has 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.

Conclusion. 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 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).

3.0.3.2.3 Boric Acid Corrosion

Summary of Technical Information in the Application. 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.

<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.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.

<u>Enhancement</u>. 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.

<u>Summary</u>. 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.

<u>Operating Experience</u>. 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 which 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 has 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 A1.4 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.

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 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).

3.0.3.2.4 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 an exception, 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, 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 where 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 due to 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 has 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 where 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 degradation mechanisms associated with cavitation erosion, solid particle erosion, etc., 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, even though 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 has 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 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).

3.0.3.2.5 Bolting Integrity

Summary of Technical Information in the Application. LRA Section B2.1.7 describes the existing Bolting Integrity Program as consistent, with exceptions and an enhancement, 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 and the use of preload control, proper selection of bolting material, and the proper selection and use of lubricants or sealants.

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-in. nominal diameter, volumetric examination comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category BG-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-in. nominal diameter are not required due to 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 since 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-in. 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 Corrective Action Program.

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, 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-in. 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, 2011, 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-in. 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-in. 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 and during the teleconference held on January 18, 2012, are resolved.

The staff also reviewed the portions of the "scope of program," "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 will 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 routine 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 management of leakage from a bolted connection using the corrective action process is an acceptable method to ensure timely detection of applicable aging effects. 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 Corrective Action Program, 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. By letter dated November 4, 2011, the applicant revised LRA Section B2.1.7 to state 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 it acceptable because it will make the program consistent with the recommendations in GALL Report AMP XI.M18, which is consistent with the guidance of EPRI TR-104213.

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, 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” 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 has 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 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 and 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. 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 Bolting Integrity Program, and review of the applicant's responses to RAIs B2.1.7-1, B2.1.7-2, and B2.1.7-3, 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 describes the existing Open-Cycle Cooling Water System Program as consistent, with an exception and an enhancement, 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. In a letter dated March 5, 2012, the applicant enhanced the program to include wall thickness measurements to address the overall system corrosion allowance. In a letter dated March 29, 2012, the applicant also enhanced the program to require engineering evaluations whenever inspections identify loss of material in piping or protective coating failures. In a letter dated July 5, 2012, the applicant further enhanced the program to require an engineering evaluation with specific conservatisms after each inspection of the piping downstream of the ECW throttle valve for the component cooling water (CCW) heat exchanger. 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."

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 27, 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 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 has 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, 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," 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 documentation of 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 Corrective Action Program 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. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M20 and finds it acceptable because, when it is implemented, the consequence of any coating degradation will be evaluated for the loss of material in the pipe wall thickness and for fouling of any downstream components. These evaluations will ensure that aging effects associated with loss of material and fouling will be managed so that the intended functions will be maintained during the period of extended operation.

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 this enhancement, the applicant committed to revise the procedures for testing and inspection of coatings to address loss of coating integrity. The staff noted that this is a newly-identified AERM. The applicant stated that the enhancement includes visual inspections every 6 years and testing (to be performed after 12 years of service at a 6-year frequency) for holidays, dry film thickness, and pull-off adhesion. The applicant stated that these inspections and tests will be performed by a qualified Nuclear Coating Specialist or by Coating Surveillance Personnel under the technical direction of such a person, and these enhancements will be implemented prior to the next scheduled inspections in 2013. The staff finds this enhancement acceptable because, when it is implemented, the revised testing protocol will consider the service life of coatings and the confirmation of coating adhesion, film thickness, and absence of holidays using qualified coating personnel will be able to detect coating degradation prior to adversely affecting downstream components. The discussion below, regarding RAIs B2.1.9-3, B2.1.9-3a, and B2.1.9-3c, provides additional information on this issue.

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, 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," 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 has 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 ultrasonic testing 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, impingement, and so on. 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 due to 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 response also states that general system inspections and various maintenance activities consider aging effects related to coating failure, and the acceptance criteria for coatings are that no erosion, corrosion, flaking, or peeling is observed. The response further states that although STP has experienced erosion of coatings in the ECW system, no sheeting-type coating failures have been observed. The response also discusses several condition reports including a recent event in 2011 (CR 11-1218) where pieces of coating were found in some of the tubes in the reactor containment building chiller, and concludes by stating the following:

> Continued implementation of the Open-Cycle Cooling Water System program (B2.1.9) and the tracking of plant operating experience provide reasonable assurance that any fouling of in-scope heat exchangers caused by protective coating failures will be adequately managed and not affect the intended function of the ECW System heat exchangers.

The staff finds 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 where 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 order to address these concerns, the staff participated in a conference call with the applicant on April 24, 2012, requesting that the applicant identify where fouling due to coating failures could adversely affect the intended function of downstream in-scope components. The staff also questioned whether coating inspections should include physical-mechanical contact to detect delaminations and whether inspection frequencies should be increased as the coating approaches its end of life (EOL). The applicant agreed to address the staff's concerns in a supplemental response to RAI B2.1.9-3a.

In its response, dated May 10, 2012, the applicant supplemented the information provided for RAI B2.1.9-3a. The response stated that, according to the vendor, the applicable coatings are not expected to delaminate in large flakes or sheets, and the vendor data sheets do not specify the use of a physical-mechanical contact type test for cure or adhesion verification. The response also stated that although a pull-off adhesion test could be used to prove that the coating has not lost any adhesive or cohesive properties, such testing results in destruction of the coating. In its review of the applicant's supplemental response, the staff identified the following three aspects where additional information is needed for locations where coating failure could adversely affect downstream components:

(1) provide the service life for each location, as established by the coating vendor or engineering evaluation and, for locations where a coating may be operated beyond its qualified service life, explain how the current program ensures downstream components are not adversely affected

(2) provide justification why no physical tests need to be periodically performed to verify coating adhesion, particularly for coatings that may be operated beyond their qualified life, during the period of extended operation

(3) provide information regarding the qualifications of individuals that will perform coatings assessments during the period of extended operation

The staff issued RAI B2.1.9-3c by letter dated July 12, 2012, requesting the applicant to address the above issues.

In its response dated August 21, 2012, 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. The applicant stated that, for the Belzona products used in the ECW system, the vendor had established a service life of approximately 20 years, and that it (the applicant) recently received updated inspection guidance that includes an expanded inspection and testing protocol for coatings that are in service for 12 or more years. The applicant also stated that the original coating (Plasticap 400 Epoxy Phenolic) in the interconnecting piping for the standby diesel generator intercooler water boxes did not have a documented service life, but this piping had been recoated with Plasite 7122, which has a vendor-supplied service life of 12-15 years.

The applicant revised its inspection and testing requirements for inservice coatings of 12 years or more to be performed at a 6-year interval and to include (a) visual; (b) low-voltage holiday test, based on ASTM D5162; (c) dry film thickness test, based on ASTM D7091 and SSPC PA-2; and (d) pull-off adhesion test, based on ASTM D4541. The applicant stated that it is revising the current inspection interval from 5 years to 6 years. This revision is based on industry and STP operating experience and aligns the interval with the vendor's inspection guidance for inservice coatings and with the applicant's 6-year major equipment outage and inspection intervals. The applicant also stated that coating inspections and tests will be performed by a qualified Nuclear Coating Specialist, as defined by ASTM D7108, or by Coating Surveillance Personnel under the technical direction of such a person. In addition, the applicant revised the appropriate sections and tables of the LRA to add AMR line items for "coatings," which are being managed for "loss of coating integrity" and revised LRA Appendix A.1.9, Appendix B2.1.9, and Table A4-1, Commitment No. 4 to reflect the above enhancement to the AMP.

Except for the 6-year inspection and testing interval, the staff finds the response acceptable because the applicant expanded its testing protocol to consider the service life of coatings and to include verification of coating adhesion, film thickness, and absence of holidays, using qualified coating personnel. The staff considers that these enhancements to the "parameters monitored" and "detection of aging effects" program elements will be able to detect coating degradation prior to adversely affecting downstream components. With regard to the 6-year inspection and testing interval, it was not clear to the staff whether plant-specific experience referenced in the response provides a sufficient basis to extend the interval from 5 years to 6 years. In addition, although the response adds line items for coatings to "maintain coating integrity," it does not integrate this intended function into LRA Table 2.1-1, "Intended Functions: Abbreviations and Definitions." The staff issued RAI B2.1.9-3d requesting the applicant to address these issues. Pending review of the applicant's RAI response, the staff's concerns described in RAI B2.1.9-3, -3a, -3c, and -3d remain unresolved and are identified as OI-3.0.3.2.6-2.

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 Corrective Action Program 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, with the exception of OI 3.0.3.2.6-2, that the applicant has 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 Corrective Action Program
- require that an engineering evaluation be performed when loss of material or coating failure is identified

The applicant also committed to enhance the procedures of the Open-Cycle Cooling Water System Program, prior to the next scheduled inspection in 2013, to visually inspect and perform tests on the coatings applied to components in the essential chilled water and standby diesel generator systems and to require that these inspections and tests be performed by appropriately qualified personnel. The staff finds that the information in the UFSAR supplement, as amended by letters dated November 4, 2011, March 5, 2012, July 5, 2012, and August 21, 2012, is an adequate summary description of the program. Therefore, the staff's concern in RAI B2.1.9-1 is resolved.

<u>Conclusion</u>. 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, with the exception of the "operating experience" program element, which is associated with OI 3.0.3.2.6-2. 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, pending resolution of OI 3.0.3.2.6-2. 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).

3.0.3.2.7 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 closed-cycle cooling water 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, 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 another operating experience example in which the BOP diesel jacket water system radiator was replaced 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 has 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.

<u>Conclusion</u>. 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.8 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

<u>Summary of Technical Information in the Application</u>. 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.

<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.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.

<u>*Enhancement*</u>. 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.

<u>*Summary*</u>. 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.

<u>Operating Experience</u>. 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 has 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 A1.11 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. 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 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 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).

3.0.3.2.9 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 has 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 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).

3.0.3.2.10 Fire Water System

Summary of Technical Information in the Application. LRA Section B2.1.13 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 carbon steel, cast iron, 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 water storage tanks exposed to raw water. The LRA also states that the AMP manages loss of material 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. The LRA further states that the program includes volumetric examinations or internal inspections of fire water piping to ensure wall thickness is within acceptable limits.

Staff Evaluation. During its audit, the staff reviewed the applicant’s claim of consistency with the GALL Report. The staff 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, flushing, and flow 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 reviewed this exception against the corresponding program element in GALL Report AMP XI.M27 and finds it acceptable for the following reasons:

- 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.
- These inspection intervals are consistent with the applicant's current, NRC-approved Fire Protection Program.
- The applicant's operating experience for the past 10 years has indicated that no degradation leading to a loss of function has occurred at this inspection frequency.

Enhancement 1. LRA Section B2.1.13 states an enhancement to the "preventive actions," "parameters monitored or inspected," and "detection of aging effects" program elements. In this enhancement, the LRA states 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. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M27 and finds it acceptable because, when it is implemented, it will be consistent with the GALL Report recommendation that wall thickness evaluations be performed to ensure the system maintains its intended function.

Enhancement 2. LRA Section B2.1.13 states an enhancement to the "detection of aging effects" program element. In this enhancement, the LRA states 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. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M27 and finds it acceptable because, when it is implemented, it will be consistent with the GALL Report recommendation that sprinkler heads are tested before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the period of extended operation to ensure that signs of degradation are detected in a timely manner.

Enhancement 3. LRA Section B2.1.13 states an enhancement to the "monitoring and trending" program element. The LRA states that procedures will be enhanced for trending of 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 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.

Summary. Based on its audit and review of the applicant's Fire Water System 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.M27. 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 "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" 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 their 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 has 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 A1.13 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.

The staff also noted that the applicant committed (Commitment No. 8) to enhance the Fire Water System Program procedures prior to the period of extended operation to include pipe wall thickness volumetric examinations or direct measurements, sprinkler replacement prior to 50 years in service or field testing of a representative sample and testing every 10 years thereafter, and trending of flow parameters recorded during fire water flow tests.

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 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 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).

3.0.3.2.11 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, 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 Technical Specifications (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 D 4057 for guidance on oil sampling. It was indicated that this standard requires that multi-level sampling be performed for tanks the size of the standby diesel generator (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, since 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 Technical Specifications, 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, 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 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 SDG 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 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 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.

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 due to 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 has 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 A1.14 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 in 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 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).

3.0.3.2.12 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, "Radiation Embrittlement of Reactor Vessel Materials," Revision 2. 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 RV 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 two 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 RV 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 RV 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 RV Surveillance Program will be used to determine P-T limits and 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 RV 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 RV 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 RV 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 RV 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 RV Surveillance Program in LRA Section B2.1.15 and the information in the safety evaluation 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 RV 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 RV 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 RV 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 RV 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 documented in SER Section 4.2. As described in the staff's review in SER Section 4.2, the staff finds that the applicant has included the materials in the RV inlet, outlet, and safety injection nozzles (including nozzle-to-shell welds) in its RV 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 RV 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 RV Surveillance Program is consistent with GALL Report AMP XI.M31, Criterion 8.

Summary. Therefore, based on its review of the applicant's RV 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 RV Surveillance Program. The applicant stated that its review of plant and industry operating experience provides reasonable assurance that the RV 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 RV 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 concurs with the applicant's conclusion as supported by the staff's approval of the current PTS evaluation and P-T limits using information from all surveillance data 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 has 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 RV 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 RV 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 RV 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 RV 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 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).

3.0.3.2.13 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 requirements of 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.

Summary. 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.

Operating Experience. 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 has 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 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).

3.0.3.2.14 Buried Piping and Tanks Inspection

Summary of Technical Information in the Application. LRA Section B2.1.18, as amended by letter dated June 16, 2011, 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, and copper alloy buried and underground limited access components 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.

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 subject to the management 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 the criterion in 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 via the condensate transfer system. The license renewal drawing does not include any 10 CFR 54.4(a)(2) termination notes for the condensate transfer system to indicate that a seismic anchor or equivalent exists. Therefore, 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 identified on license renewal drawing LR-STP-NL-6T180F00078, Revision OA, at locations C7 and G8, 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 AFW storage tank (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 has 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 and the followup to RAI B2.1.18-1 are resolved.

During its audit of the basis document for LRA Section B2.1.18, “Buried Piping and Tanks Inspection,” 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, “[t]he staff considers backfill that is located within 6 in. of the pipe that meets ASTM D448-08 size number 67 to meet 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, 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, and the backfill 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 applicants 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 that based on the results of these inspections, 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, and 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 there has not been any damage to coatings. 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.

During its audit of the basis document for LRA Section B2.1.18, “Buried Piping and Tanks Inspection,” under the “detection of aging effects” program element, the staff noted that the document does not state an inspection size for the underground in-scope oily waste system piping. GALL Report AMP XI.M41 recommends that 2 percent of underground piping containing materials hazardous to the environment be inspected. It was not clear to the staff if underground in-scope oily waste system piping is included in the inspection. By letter dated August 15, 2011, the staff issued RAI B2.1.18-4 requesting that the applicant state why there are no inspections for the underground in-scope oily waste system piping.

In its response dated September 15, 2011, the applicant stated that the in-scope oily waste buried piping is nonsafety-related and is within the scope of license renewal per the criterion in 10 CFR 54.4(a)(3) to remove firewater from the diesel generator rooms in the event of a fire or to remove fuel oil in the event of a fuel oil spill. The applicant also stated that it considers the piping to be empty and to not contain oily waste. Therefore, the applicant concluded that the piping does not contain hazmat; thus, no inspections are required for the buried portions of the oily waste system piping managed by the Buried Piping and Tanks Inspection Program.

The staff finds the applicant's response acceptable because the oily waste system piping is considered to be empty and only contains fluid during an event. GALL Report AMP XI.M41, Table 4a, note 5, states that "[h]azmat pipe is pipe that, during normal operation, contains material that, if released, could be detrimental to the environment." Since the piping does not normally contain "hazmat," no inspections are recommended. The staff's concern described in RAI B2.1.18-4 is 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 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 B2.1.18 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 NACE SP0169, Section 5.2.3. The staff reviewed this exception against the corresponding program element in GALL Report AMP XI.M41. GALL Report AMP XI.41, in Table 2a, notes 5 and 6, state that "[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, and the applicant would take appropriate corrective actions. Additionally, the staff noted that the applicant has 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 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 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, which are consistent with the intent of the American Water Works Association (AWWA) coating standards called out in NACE SP0169-2007. The staff reviewed this exception against the corresponding program element in GALL Report AMP XI.M41. GALL Report AMP XI.M41, in Table 2a, note 2, states, "[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. Therefore, the staff finds that the exception is acceptable.

Enhancement 1. LRA Section B2.1.18 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 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 in. 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; and qualifications for the performance technicians who perform the plant yard cathodic protection system annual surveys. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M41, which provides acceptance for backfill located within 6 in. of the buried piping. It 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.

Enhancement 3. LRA Section B2.1.18 states an enhancement to the “parameters monitored or inspected” and “detection of aging effects” program elements. In this enhancement, the applicant stated that that plant procedures will be enhanced to include visual inspections of piping and supplemental surface or volumetric non-destructive testing (or both) if significant degradation is observed. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M41, which state that loss of material is monitored by visual appearance of the exterior of the piping or tank and wall thickness of the piping or tank, and visual inspections are supplemented with surface or volumetric non-destructive testing (or both) if significant indications are observed. 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 4. LRA Section B2.1.18 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; the 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; credit for inspection of shared piping between units; examination of piping, valves, and bolting when exposed; two alternatives for inspections of buried or underground piping that is safety-related, hazmat or both; flow testing of fire mains; the definition for “hazmat” piping; examples of adverse conditions; corrective actions for adverse conditions; and the scope of inspection and inspection requirements for buried piping and buried and underground stainless steel piping.

GALL Report AMP XI.M41, under the "detection of aging effects" program element, states, "[i]f adverse indications are detected, inspection sample sizes within the affected piping categories are doubled. If adverse indications are found in the expanded sample, the inspection sample size is again doubled. This doubling of the inspection sample size continues as necessary." LRA Section B2.1.18, under the enhancement for the "detection of aging effects" program element, states that if extensive adverse conditions are found during inspections, inspections may be halted in an area of concern that is planned for replacement, provided continued operation does not pose a significant hazard. The LRA enhancement statement does not appear to be consistent with the statement in the GALL Report AMP because the LRA does not state whether the doubling of inspection sample sizes will continue in locations with similar materials and environments. By letter dated August 15, 2011, the staff issued RAI B2.1.18-3 requesting that the applicant describe what actions will be taken for areas of similar material and environment where adverse conditions are not extensive.

In its response dated September 15, 2011, the applicant stated that it considers the words "affected piping categories" to be equivalent to "locations with similar materials and environment." The applicant stated that it will revise its basis document AMP to clarify that when adverse indications are detected, the sample size will expand in locations with similar materials and environment.

The staff finds the applicant's response acceptable because the applicant clarified that the expanded sample size will include locations with similar materials and environments, which is consistent with the recommendation in GALL Report AMP XI.M41. The staff's concern described in RAI B2.1.18-3 is resolved.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M41 and finds it 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 5. LRA Section B2.1.18 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. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M41, which states that for piping and tanks protected by cathodic protection systems, potential difference, and current measurements are trended to identify changes in the effectiveness of the systems or coatings (or both). 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 6. LRA Section B2.1.18 states an enhancement to the "acceptance criteria" program element. In this enhancement, the applicant stated that plant procedures will be enhanced to include actions if coating degradation is present; acceptability of backfill that is located within 6 in. of the pipe that is consistent with ASTM D448-08 size number 67; and actions for the condition "without leakage," as required by 49 CFR 195.302. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M41, which provides recommended acceptance criteria for degraded coatings and specifications for backfill. Additionally, the GALL Report states that for hydrostatic tests, the condition "without leakage," as required by 49 CFR 195.302, may be met by demonstrating that the test pressure, as adjusted for temperature, does not vary during the test. 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 7. LRA Section B2.1.18 states an enhancement to the "detection of aging effects" and "acceptance criteria" program elements. In this enhancement, the applicant stated that a list of the systems with buried or underground piping within the scope of this program will be developed, including whether or not the pipe is safety-related or contains hazmat for each piping material and system within the scope of this program and whether or not the coating, backfill, and cathodic protection of the piping comply with NACE SP0169-2007 and the other requirements of Section XI.M41, Table 2a of the GALL Report, Revision 2. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M41. The "acceptance criteria" program element in GALL Report AMP XI.M41 recommends that backfill be in accordance with specifications described in the "preventive actions" program element of the AMP. The "preventive actions" program element states that preventive actions for buried piping and tanks are conducted in accordance with Table 2a and its accompanying footnotes. The "detection of aging effects" program element in GALL Report AMP XI.M41 outlines the methods and frequencies used for the detection of aging effects for buried and underground piping and tanks. 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.

Summary. Based on its audit and review of the applicant's responses to RAIs B2.1.18-1, B2.1.18-2, B2.1.18-3, and B2.1.18-4 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," 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 B2.1.18 states that a review of 10 years of plant operating experience produced 30 events, which were associated with buried piping. Nine of these events were related to systems or components in scope of license renewal. The applicant stated that all of these events were leaks shown to not be a result of corrosion of materials, making them not relevant to this program. The applicant also reviewed industry operating experience and identified six relevant events involving buried piping.

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 has 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 A1.18 provides the UFSAR supplement for the Buried Piping and Tanks Inspection Program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the applicant committed (Commitment No. 13) to enhance the existing Buried Piping and Tanks Inspection Program, as described in LRA supplement 2, dated June 16, 2011, 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.15 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 in. 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, non-destructive 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 has 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 which 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 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. The staff issued RAI B2.1.19-4 by letter dated February 28, 2012, 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 in. 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 has 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 A1.19, 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 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).

3.0.3.2.16 External Surfaces Monitoring Program

Summary of Technical Information in the Application. LRA Section B2.1.20 describes the new External Surfaces Monitoring Program as consistent, with exceptions, 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 to identify aging effects and leakage for steel, stainless steel, aluminum, and copper alloy components, and 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.

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.

The “scope of program” program element of GALL Report AMP XI.M36 states that cracking is an aging effect managed by the program for stainless steel components exposed to an outdoor air environment. However, the applicant’s External Surfaces Monitoring Program does not state that it manages cracking. The staff reviewed the applicant’s LRA and implementing procedures and finds this acceptable because the applicant stated in the LRA that the STP plant outdoor air environment is not subject to industry air pollution or a saline environment; thus, stainless steel does not experience any appreciable aging effects, which excludes the need for cracking to be managed under this AMP. Additionally, the implementing procedure already conservatively includes cracking as an inspection parameter for routine walkdowns conducted to manage loss of material on external surfaces of components within the scope of this AMP. The staff notes that newly identified components within the scope of this AMP must be provided in future UFSAR updates along with a description of how the effects of aging will be managed such that the intended functions will be effectively maintained during the period of extended operation, as required by 10 CFR 54.37(b).

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 or not to physically manipulate elastomers during visual examinations; therefore, it is not clear whether or not 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.

Summary. Based on its audit, review of the applicant’s responses to RAIs B2.1.20-1, B2.1.20-3, and B2.1.20-4, and review of the applicant’s External Surfaces Monitoring 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.M36. 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.

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 has 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 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 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).

3.0.3.2.17 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 reactor vessel.vessel The applicant further stated that the program implements the recommendations of NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors." The applicant stated that the flux thimble tubes are scheduled to be inspected during each RFO 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 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 six 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.

Enhancements. 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 in. and were replaced in September of 1989 with thicker tubes with an outer diameter of 0.385 in. 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 in. outer diameter tubes. The applicant also stated that since the change to the 0.385 in. 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 in. 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 of 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 22 tubes were repositioned by approximately 2 ½ in. 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 has 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 has 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 has 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 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).

3.0.3.2.18 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

Summary of Technical Information in the Application. LRA Section B2.1.22 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." The LRA states that the AMP addresses the internal surfaces of piping, piping components, ducting, 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 the work control process for periodic, predictive, and corrective maintenance and surveillance testing to conduct and document inspections using visual inspections and supplemental inspections at intervals and locations where the likelihood of significant degradation has been assessed. The LRA further states that the program may be augmented by physical manipulation of elastomeric surfaces and the use of volumetric evaluations to detect SCC on the internal surfaces of stainless steel components exposed to diesel exhaust.

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 (closed-cycle cooling water) 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 closed-cycle cooling water, 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, 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, the external elastomeric components are excluded from this scope and are addressed in another AMP, and the tank's inclusion includes an inspection method that is adequate and appropriate for determining aging effects for tank bottom's loss of material. 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 has 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.

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.

Exception. LRA Section B2.1.22 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 stainless steel, aluminum, copper alloy, stainless steel-cast austenitic, nickel alloys, glass, and elastomers, in addition to steel 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 appropriate, for the component configuration and material, and by volumetric evaluation to detect SCC of the internal surfaces of stainless steel components exposed to diesel exhaust.

The staff reviewed and accepted the applicant’s response to RAI B2.1.22-1 as discussed above.

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, Revision 2. 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.

Summary. Based on its audit, and review of the applicant’s responses to RAI B2.1.22-1, RAI B2.1.22-2, RAI B2.1.22-3, RAI B2.1.22-4, and RAI B2.1.20-1, 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. 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 September 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 has 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 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.

LRA Section A1.22 was requested to be revised based on RAI B2.1.22-4, as discussed above, and the applicant's response on this issue was accepted in the staff evaluation section. LRA Section A1.22 was also revised based on RAI SBPB-2-2, discussed above, and the staff evaluation to this applicant's response is found in SER Sections 2.3.3.5.2, 3.3.2.2.5, and 3.3.2.3.5.

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 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).

3.0.3.2.19 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 standby diesel generator oil for total particle count does not yield an accurate count due to 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.

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 Operating Experience Program that monitors industry issues and assess them for applicability to its own operation. Furthermore, it was stated that the Corrective Action Program 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 has 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 A1.23 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 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).

3.0.3.2.20 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 dated 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 dated 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 has 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 all in-scope non-EQ inaccessible medium voltage cables exposed to significant moisture simultaneously with significant voltage are 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 Corrective Action Program 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," 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 has 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 dated 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 has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.21 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 MEB 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.

Enhancement. 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.

Summary. 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 which 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 in. 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 in. 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 which clearly indicated that the cracked Noryl was replaced or repaired. The applicant also provided a PMWO which 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 has 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 A1.26 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.

<u>Conclusion</u>. 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 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).

3.0.3.2.22 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, 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 or not 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 has 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 or not 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-in. 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 or not 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 has 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.

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 or not 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 has 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 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).

3.0.3.2.23 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. 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, (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 in., whereas ACI 349.3R states that passive cracks less than 0.015 in. 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 in. 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.

Enhancement. 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.

Summary. 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.

Operating Experience. 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 were reviewed by the applicant. 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 liftoff 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 90 °F. The applicant used tests at 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 has 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. 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 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 in. 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 Section 3.0.3.2.5 of this SER. 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 in. 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 Corrective Action Program 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 Corrective Action Program. 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 corrective action program 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 has 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 A1.29 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.

<u>Conclusion</u>. 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 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).

3.0.3.2.25 10 CFR Part 50, Appendix J

<u>Summary of Technical Information in the Application</u>. LRA Section B2.1.30 describes the existing 10 CFR Part 50, Appendix J Program as consistent, with 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 “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 testing, subsequent to the administration of the 15-year Type A test.

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 has 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 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 regards 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 for 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 determined the same in SER Section 2.1.3.2, under "Scoping and Screening Program Review," after evaluating the applicant's response to a similar inquiry described in RAI 2.1-4 (i.e., no LSS or NRS SSCs were excluded from the population categories of 10 CFR 54.4). 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 RFO 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 dated 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, 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 closed-cycle cooling water 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 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-in. 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 has 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 A1.30 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) to enhance the 10 CFR Part 50, Appendix J Program procedures to specify a surveillance frequency of 10 years following a successful ILRT.

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 enhancement and confirmed that its implementation through Commitment No. 24 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-in. 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-in. 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. 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 five 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 has 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.

<u>Enhancement 2</u>. 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.

<u>Enhancement 3</u>. 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.

<u>Enhancement 4</u>. 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.

<u>Summary</u>. 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.

<u>Operating Experience</u>. 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 Corrective Action Program 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 is 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 Corrective Action Program.

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 which 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 prior to 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 prior to 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 five years to conduct the appropriate GALL Report-recommended visual inspections, and although the applicant utilized 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 has 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 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.

<u>Conclusion</u>. 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 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).

3.0.3.2.27 RG 1.127, Inspection of Water Control Structures with Nuclear Power Plants

Summary of Technical Information in the Application. LRA Section B2.1.33 describes the existing RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program as consistent, with an enhancement, 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 emergency cooling water (ECW) systems. The AMP is committed to conform to the intent of RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," with respect to the essential cooling 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.

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 has 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, Inspection of Water-Control Structures Associated with Nuclear Power Plants 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. 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.

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 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 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 has 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.

Detection of Aging Effects. The staff also reviewed the portions of the "detection of aging effects" program element associated with enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this enhancement follows.

Enhancement. LRA Section B2.1.33 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that procedures will be enhanced to specify inspection intervals not to exceed 5 years, or immediately following significant natural phenomena. By letter dated November 30, 2011, the applicant submitted its annual update to the LRA. In the update, the applicant stated that the interval for sediment monitoring of the ECP was 10 years. The applicant explained that the only makeup sources 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 frequency interval for sediment surveys from 5 to 10 years will have no effect on the ECP design function.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and finds it acceptable because, when it is implemented, it will align the general AMP inspection interval with the 5-year inspection interval recommended in GALL Report AMP XI.S7. The staff also reviewed the extended frequency specifically associated with sediment monitoring of the ECP and found it acceptable because the applicant has no experience with sediment collection in the ECP and because the makeup sources do not provide a likely path for sediment to enter the pond.

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, 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. In addition, the staff reviewed the enhancement associated with the "detection of aging effects" program element and finds that, when implemented, it will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.33 summarizes operating experience related to the 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 in. The report also indicated that deflections measured using benchmark elevations along buried ECW pipe routes were found to be within the allowable 1.5 in., 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 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 "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 program element 4, "detection of aging effects," which states that the program will be enhanced to specify inspection at intervals not to exceed 5 years. However, it does not clearly state that concrete structures below the water-line will be inspected on this frequency. It is 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 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 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-69.

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 has 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 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).

3.0.3.2.28 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 15, 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 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/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, prior to 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 takento 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-adjusted CUF (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.

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 prior to 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 because the applicant clarified that corrective actions are taken when an action limit is reached. The applicant will take and complete corrective actions prior to 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 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 environmentally-assisted fatigue. To achieve this objective, the applicant can (1) re-evaluate the entire RCPB for environmentally-assisted fatigue, 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 conservative that this transient was included as part of the LBB analysis, even though the transient does not occur at the applicant's site. 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. The staff noted that, 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.

Summary. 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," 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. More specifically, 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 eleventh 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 was 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 has 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 letter dated November 21, 2011, 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.)
- 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 or augmented inspections. 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 has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3 AMPs That Are Not Consistent with or Not Addressed in the GALL Report

In LRA Appendix B, the applicant identified the following AMPs as plant-specific programs:

- Nickel-Alloy Aging Management Program
- PWR Reactor Internals
- Selective Leaching of Aluminum Bronze
- Protective Coating Monitoring and Maintenance Program

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 section of the SER.

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 components to 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)(E)(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 has 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.

UFSAR Supplement. 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.

Conclusion. On the basis of its technical review of the applicant's Nickel-Alloy Program, the staff concludes that the applicant has 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

Summary of Technical Information in the Application. In LRA Section B.2.1.35, the applicant described its PWR Vessel Internals Program, stating that this new 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's PWR Reactor Internals Program manages cracking, loss of material, loss of fracture toughness, dimensional changes, and loss of preload for RV 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."

<u>Staff Evaluation</u>. The staff reviewed the applicant's claim of consistency with the GALL Report, Revision 1, AMP XI.M16, which states that the guidance for the aging management of PWR vessel internals is provided in the AMR items of Chapter IV.

The management of postulated aging effects that may occur in PWRs is covered in the following LRA Sections:

- LRA Section 3.1.2.2.6, "Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement and Void Swelling"
- LRA Section 3.1.2.2.9, "Loss of Preload Due to Stress Relaxation"
- LRA Section 3.1.2.2.12, "Cracking Due to Stress Corrosion Cracking (SCC) and Irradiation-Assisted Stress Corrosion Cracking (IASCC)"
- LRA Section 3.1.2.2.15, "Changes in Dimensions Due to Void Swelling"
- LRA Section 3.1.2.2.17, "Cracking Due to SCC, Primary Water Stress Corrosion Cracking (PWSCC), and IASCC."

No further evaluation is recommended by the GALL Report if the applicant's commitment specified under the Table IV.B2 column heading "Aging Management Program" for these reactor vessel internals (RVIs) (or, items) is confirmed. Commitment No. 27 (LRA Appendix A, Table A4.1) states that the applicant will implement the PWR Reactor Internals Program, as described in LRA Section B2.1.35, within 24 months of the issuance of EPRI 1016596, "PWR Internals Inspection and Evaluation Guideline MRP-227-A." 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).

In addition to GALL Report guidelines, MRP-227-A addresses two active aging degradation mechanisms—wear (MRP-227-A, Section 3.2.3) and fatigue (MRP-227-A, Section 3.2.4). Inspection and evaluation is monitored through the inspection and evaluation guidelines addressed in MRP-227-A, Tables 4-3, 4-6, and 4-9, for Westinghouse plants.

The above commitment is also stated in SRP-LR Sections 3.1.2.2.6, 3.1.2.2.9, 3.1.2.2.12, 3.1.2.2.15, and 3.1.2.2.17. By comparing the contents of the applicant's PWR Reactor Internals

Program and LRA Commitment No. 27 with the commitments recommended in the SRP-LR and GALL Report Table IV.B2, the staff concludes that the applicant's PWR Reactor Internals Program and Commitment No. 27 are acceptable for meeting the recommended commitment in SRP-LR for specific PWR RV internals. Therefore, the staff considers the applicant's PWR Reactor Internals Program as a means for fulfilling Commitment No. 27 in regards to meeting a key aging management guideline provided in SRP-LR Sections 3.1.2.2.6, 3.1.2.2.9, 3.1.2.2.12, 3.1.2.2.15, and 3.1.2.2.17 for specific PWR reactor internals.

The staff confirmed that the AMP for LRA Sections 3.1.2.2.12 and 3.1.2.2.17 also requires control of water chemistry to mitigate the specific aging mechanism(s). The staff's evaluation of the Water Chemistry Program can be found in SER Section 3.0.3.2.1.

Scope of Program. The applicant stated that the scope of the program "applies to the Guidance of MRP-227-A, which provides augmented inspection and flaw evaluation methodology for assuring the functional integrity of Westinghouse RV internals." The applicant's PWR Reactor Internals Program includes the Westinghouse-designated primary components in MRP-227-A, Table 4-3, Westinghouse-designated expansion components in MRP-227-A, Table 4-6, and applicable MRP-227-A methodology license renewal applicant action items. 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).

Preventive Actions. 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 finds 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 AMP. The staff's evaluation of the Water Chemistry Program can be found in SER Section 3.0.3.2.1.

Parameters Monitored or Inspected. The applicant stated that the PWR Reactor Internals Program monitors the aging effects of cracking, loss of material, loss of fracture toughness dimensional changes, and loss of preload through inspection in accordance with the guidance of MRP-227-A or ASME Code Section XI, Category B-N-3. The staff confirms that monitoring and inspecting these aging effects is consistent with the inspection guidance of MRP-227. MRP-227 also identifies existing program components whose aging effects are managed consistent with ASME Code, Section XI, Table IWB-2500-1, Examination Category B-N-3.

Detection of Aging Effects. 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, Tables 4-3, 4-6, and 4-9, respectively. The staff confirmed that these are the appropriate tables for Westinghouse-designated components.

Monitoring and Trending. 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 examinations 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 implement corrective actions. Detected conditions that do not satisfy the examination acceptance criteria (element 6) are required to be dispositioned through a Corrective Action Program (element 7), which may require repair, replacement, or analytical evaluation for continued service until the next inspection. The staff concluded that this element is consistent with the monitoring and trending criteria of MRP-227-A.

Acceptance Criteria. The applicant stated that the examination acceptance criteria for the primary and expansion component examinations are consistent with Section 5 of MRP-227-A. ASME Code Section XI IWB-3500 acceptance criteria are applicable to existing programs' components. The staff finds this consistent with the applicant's commitment to follow the guidance of MRP-227-A.

Corrective Actions. The applicant stated the following:

> 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)
>
> (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

Relevant indications failing to meet applicable acceptance criteria are repaired or replaced in accordance with plant procedures. Appropriate codes and standards are specified in both the "ASME Code Section XI Repair, Replacement, and Post-Maintenance Pressure Testing" procedure and in design drawings. The staff confirms that the corrective actions listed, as appropriate, are consistent with MRP-227-A and ASME Code Section XI.

Confirmation Process and Administrative Controls. The applicant stated that the QA requirements for repair and replacement activities are also included in its Operations QA Plan. Since the applicant's site QA procedures, review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B, the staff finds them acceptable in addressing corrective actions. The QA Program is applicable to the safety-related and nonsafety-related SSCs that are subject to an AMR.

Summary. 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.

Operating Experience. 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 U.S.; 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.

Based on its review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. 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. 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.

Conclusion. 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, combined with the other specific AMPs, the applicant has 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

Summary of Technical Information in the Application. LRA Section B2.1.37, as amended by letters dated June 16, 2011, May 31, 2012, and October 4, 2012, describes the existing Selective Leaching of Aluminum Bronze Program as plant-specific. The LRA states that the AMP addresses aluminum bronze (copper alloy with greater than 8 percent aluminum) components 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 piping through periodic external visual inspections for dealloying in all susceptible aluminum bronze components. 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. As amended, the program includes periodic destructive examination and testing of susceptible components to update the analyses the applicant has performed to determine the extent of selective leaching that has occurred as a result of continued exposure to the raw water environment and confirm the structural integrity of the affected components.

Staff Evaluation. Selective leaching involves the dealloying, or depletion, of aluminum at the microstructure level from within susceptible aluminum bronze alloys. Based on the alloys used during construction, this phenomenon primarily affects cast valve bodies, cast fittings, and the associated heat-affected zones of field welds and buried piping welds. The staff noted that selective leaching of aluminum bronze has been occurring at STP since at least 1988 and can be expected to continue through the period of extended operation.

Summary of Staff Evaluation: This portion of the SER provides a brief discussion of the staff's evaluation of the Selective Leaching of Aluminum Bronze Program. From a broad perspective, the aging effects of susceptible aluminum bronze components are currently being managed by:

- **Inspection**: Conducting periodic walkdowns in order to detect external visual evidence of leakage that is indicative of internal dealloying or dealloying and cracking and yard walkdowns to detect evidence of standing water that could be indicative of leaking buried essential service water piping.
- **Analysis**: Using a plant-specific correlation to size the internal flaw based on the observed evidence of external leakage. Then, using stress analysis output curves to determine whether the component has sufficient structural integrity based on local pipe design loads and the assumed internal flaw size.
- **Replacement**: Replacing the degraded component by the next refueling outage.

Given that the components are predominately ASME Code Section XI Class III items, the applicant has, for past instances of leakage, applied for relief from ASME Code Section XI requirements to allow operation to the next refueling outage. Conducting periodic inspections, determining whether leaking components meet structural integrity requirements, and replacing the degraded components have been the means for managing the degradation since the first degradation was observed and is documented in the applicant's UFSAR, Appendix 9A, "Assessment of the Potential Effects of Through-Wall Cracks in ECWS Piping."

In order to accept this approach to managing aging during the period of extended operation, as proposed by the applicant, the staff has determined that the applicant must be able to demonstrate that the program can accomplish three critical objectives. If these objectives cannot be accomplished during the period of extended operation, then the staff will not be able to conclude that there is a reasonable assurance that effects of selective leaching on susceptible aluminum bronze will be adequately managed. The objectives are as follows:

(1) The external visual inspections described in the "parameters monitored/inspected" and "detection of aging effects" program elements must be capable of measuring the external size of a flaw during periodic walkdowns of aboveground components and converting this to a projected internal flaw. The staff's evaluation of inspections related to susceptible buried components is documented below in the section titled, "Leakage Detection for Buried Components."

(2) The “acceptance criteria” program element input must be based on accurate analyses conducted to demonstrate structural integrity of components in various stages of degradation.

(3) The periodicity and quantity of inspections described in the “detection of aging effects” program element must be adequate to ensure 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.

In regard to the first and second objectives, during its audit and subsequent review of documents, the staff determined that some of the input parameters for the structural integrity analyses use as-supplied or as-specified values, in lieu of those obtained from dealloyed specimens (e.g., yield strength, fracture toughness); thus, the analyses may not be conservative. The staff also determined that there was ambiguity in relation to the methods used to correlate the external flaw dimensions to internal flaw dimensions. As a result, the staff conducted a supplemental audit on February 29, 2012. During this audit, the staff reviewed further documentation provided by the applicant regarding component testing that had been performed to validate the structural integrity analyses and the flaw size correlation. Based on a review of this documentation, the staff questioned the adequacy of this validation testing and was unable to conclude that the applicant’s aging management approach was acceptable.

Regarding the third objective, to date, the applicant has conducted walkdowns of 100 percent of the susceptible components every six to nine months. The applicant has proposed to conduct the same inspections during the period of extended operation. However, as described below in the section titled, “*Correlating Visual Evidence of External Degradation to Internal Degradation*,” until 2012, the applicant had not sectioned and inspected any degraded components since 1994. The applicant will conduct further tests and examinations of degraded components and submit the results to the staff. The results of this testing could demonstrate that the progression of dealloying over the past 19 years warrants more frequent walkdowns or utilization of inspection techniques other than external visual inspections.

The staff issued a series of RAIs, B2.1.37-1, B2.1.37-2, B2.1.37-3, and B2.1.37-4, and the applicant responded. As noted in Table 3.0-2 below, the staff issued RAI B2.1.37-5 by letter dated December 18, 2012, and the response is outstanding. The following table presents a summary of the status for each RAI by its related parts, along with whether the response to the part is acceptable. For issues where the response is acceptable and has fully addressed an aspect of the RAI, the evaluation that discusses the basis for the satisfactory finding is included below.

Table 3.0-2. Summary Status of RAI Parts related to OI 3.0.3.3.3-1

RAI Number	Date Issued	Response Date	RAI Sections Found Acceptable	RAI Sections Found Not Completely Acceptable
B2.1.37-1	September 21, 2011	December 8, 2011	2	1
B2.1.37-2	September 21, 2011	December 8, 2011	5	1, 2, 3, 4, 6
B2.1.37-3	April 12, 2012	May 31, 2012	a, c, f, j	b, d, e, g (aboveground portions), h, i
B2.1.37-4	July 26, 2012	October 4, 2012	6, 7, 8	1, 2, 3, 4, 5
B2.1.37-5	December 18, 2012	Response not yet received		

The principal focus of these RAIs was to resolve the issue regarding the use of as-supplied or as-specified material property inputs, in lieu of those obtained from dealloyed specimens, in the structural integrity analyses. Due to the large number of RAIs as listed in Table 3.0.3.3.3-1, the staff conducted a public meeting on August 27, 2012 to discuss the applicant's proposed responses to RAI B2.1.37-4. During this public meeting, the applicant proposed an alternative approach, whereby the structural integrity analyses could be demonstrated as acceptable by either obtaining dealloyed material properties or performing empirical testing (e.g., conducting a sufficient number of tests on dealloyed specimens to validate the analyses). The applicant subsequently responded to RAI B2.1.37-4 by letter dated October 4, 2012.

In addition, given that the applicant developed the flaw size correlation based on a limited examination of removed, dealloyed components, the staff noted that the number of tested samples would have to be increased in order to empirically demonstrate the validity of the structural integrity analyses used to develop the input for the "acceptance criteria" program element. The staff's review of RAI B2.1.37-4 related to these issues resulted in the issuance of RAI B2.1.37-5.

Given the number of issues in each RAI and the necessity for followup questions, the following staff evaluation has been formatted to reduce complexity, yet still present (a) the evaluation of open issues involved, (b) a discussion of each open followup RAI question, (c) a discussion of each closed RAI question, and (d) the evaluation of each AMP program element that has currently been found acceptable. Two of the program elements, "scope of program" and "preventive actions," have been found acceptable by the staff and their evaluations are included below. The staff lacks information to confirm that the "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements satisfy the criteria defined in SRP-LR Section Appendix A. These four program elements remain open pending resolution of OI-3.0.3.3.3-1.and will not be addressed at this time.

The following SER input provides the staff's position on several key aspects related to the proposed plant-specific program including:

- quantity and size distribution of remaining components susceptible to dealloying
- phase composition of the dealloyed regions
- flaw morphology
- correlating visual evidence of external degradation to internal degradation
- detecting degree of dealloying
- structural integrity analytical method
- specific analytical input values
- acceptance criteria
- components of one inch nominal pipe size and smaller
- leakage detection for buried components
- flooding, reduction in flow, and water losses for the ECP
- trending of material properties

<u>Quantity and Size Distribution of Remaining Susceptible Components</u>. During the public meeting, the applicant stated that there are approximately 350 remaining susceptible components in the ECW system. By letter dated December 18, 2012, the staff issued RAI B2.1.37-5, Part (g), in part, requesting that the applicant provide a list of the number of

remaining susceptible components by size. This list is required for the staff to evaluate the proposed scope of component testing.

Phase Composition of Dealloyed Region. The staff reviewed the application, the UFSAR, and industry literature and determined that the phase composition of the dealloyed region was not clear. The staff noted that the size and distribution of dealloying-susceptible phases affect the potential degree of degradation and correspondingly, the component strength. By letter dated April 12, 2012, the staff issued RAI B2.1.37-3, Part (a), requesting that the applicant state which phase(s) of the material are significantly present, which phase is the continuous phase, and which phase(s) are dealloyed. In addition, given the composition of the dealloyed components identified to date, the staff requested information regarding the basis for the conservativeness of the ultimate tensile strength used in the structural analysis of the degraded components.

In its response dated May 31, 2012, the applicant stated that the vulnerable phases of the aluminum bronze alloy are beta and gamma 2. The beta phase forms when the aluminum content is above 8 percent. The gamma 2 phase forms when the alloy is allowed to cool too slowly from temperatures above 600 °C. The presence of iron above 2 percent suppresses the formation of the gamma 2 phase and, as a result, any gamma 2 is more likely to be discontinuous. Nickel has a similar impact to that of iron. The applicant stated that its aluminum bronze components have approximately 4 percent iron content. The applicant supplied several micrographs taken from removed components. Table A-2 in the response states that samples removed from the system showed a continuous network of beta dealloying. The applicant also stated that cross-sectional testing performed in 2012 demonstrated that the metallurgical phases are essentially the same as those found early in plant life. The applicant further stated that it established the ultimate tensile strength value based on testing several samples of varying range of aluminum composition and will test additional samples.

The staff noted that the applicant did not provide a sufficient basis for the conservativeness of the ultimate tensile strength used in the structural analysis of the degraded components. However, the staff also noted that the applicant’s response to RAI B2.1.37-4 stated that the applicant will use an empirical approach to demonstrate that its analytical methodology is conservative (as described below), rather than attempting to obtain dealloyed material properties. As a result, the portion of the RAI related to stating a basis for the conservativeness of the ultimate tensile strength became moot. The staff evaluated this response based on not considering this portion of the RAI. The staff finds the applicant’s response acceptable for the remainder of RAI B2.1.37-3, Part (a), because it adequately describes the phases of the aluminum bronze alloy that are susceptible to selective leaching and provides micrographs and an explanation that the dealloyed region can be the continuous phase. The staff’s concern described in RAI B2.1.37-3, Part (a), is resolved.

Flaw Morphology. The staff reviewed the application, UFSAR, and industry literature and determined that the flaw morphology of dealloying and crack propagation was not clear. The staff noted that the assumed flaw morphology affects the calculations used to predict flaw propagation under design loads, and therefore the input to the “acceptance criteria” program element. By letter dated April 12, 2012, the staff issued RAI B2.1.37-3, Part (c), requesting that the applicant describe the initial flaw morphology (e.g., dealloying, crack), state how the flaw propagates, and describe whether the through-wall flaws are developed only from through-wall dealloying degradation (i.e., 100 percent dealloying through thickness) or by cracking mechanisms such as SCC or fatigue. In addition, the staff asked the applicant to provide the basis for the 30 ksi ultimate tensile strength value used in the structural integrity analyses for 100 percent dealloyed material.

In its response to RAI B2.1.37-3, Part (c), dated May 31, 2012, the applicant clarified the morphology by stating "[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." The applicant also stated, "The 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 further stated, "Destructive examinations were not performed for all cases. Therefore, it cannot be concluded whether the root cause of the flaw was due to dealloying or other crack mechanisms." The applicant stated that it had not experienced any catastrophic failures due to dealloying, and operating experience data supported by test data demonstrated that a dealloyed component retains sufficient material strength to allow replacement at the first available opportunity.

The staff finds the applicant's response acceptable for RAI B2.1.37-3, Part (c), because it describes the morphology of the flaws as being due to dealloying only, or by a combination of dealloying and crack propagation; therefore, it confirmed that the analytical basis for acceptance needs to include both limit load and fracture mechanics methodologies. The staff does not accept the applicant's explanation that operating experience data supported by test data demonstrates that a dealloyed component retains sufficient material strength to allow replacement at the first available opportunity. The explanation is not sufficient in that it does not provide a basis for why 100 percent dealloyed material still retains 30 ksi ultimate tensile strength. However, given that the analytical methodology will be empirically demonstrated (as described below) and that further testing will be conducted, the staff evaluated this response without considering this portion of the RAI. The staff's concern described in RAI B2.1.37-3, Part (c), is resolved.

Correlating Visual Evidence of External Degradation to Internal Degradation. The applicant has not provided a sufficient basis to demonstrate that the extent of internal dealloying or cracking is adequately understood. The staff noted that the applicant's structural integrity analysis methodology depends on the ability to size internal degradation using external visual examinations. In 1994, the applicant conducted profile examinations (PE) of eight dealloying components. PEs involve the preparation of a metallurgical cross-section of a component to reveal the progression of dealloying or cracking through the component wall. The results are documented in the applicant's report AES-C-1964-5 (by APTECH Engineering), "Evaluation of the Significance of Dealloying and Subsurface Cracks on Flaw Evaluation Method." These samples were examined for the degree of dealloying around the circumference of the component and were measured for the extent of cracking, when present. During the staff's audits and subsequent evaluation of this program, the staff determined that the applicant had used the results of the PEs to develop a correlation methodology to project the potential internal size of cracks based on external visual indications (i.e., OD crack angle or OD degree of degradation). The staff noted that the program does not use volumetric techniques to size potential internal cracks. The projected internal flaw size is then used as an input to a structural integrity analysis of the degraded component. As stated above, the structural integrity analysis provides the input to the "acceptance criteria" program element. The staff also noted that no further PEs were conducted subsequent to those performed in 1994. The staff believes that eight PEs do not provide a sufficient amount of data to conclude that the correlation would be bounding through the end of the period of extended operation.

Subsequent to the public meeting conducted on August 27, 2012, the staff continued its evaluation regarding an acceptable quantity of examinations and concluded that an additional 14 PEs would be required to establish a reasonable basis that external visual indications could be used to estimate internal flaw sizes. The additional 14 PEs will result in a total of 22 PEs being conducted, including those already documented in AES-C-1964-5. The staff determined that the PEs should consist of testing/examining for chemical composition (including aluminum content), mechanical properties, microstructure, degree of dealloying, and cracking in order to establish the progression of dealloying and to confirm the acceptability of using the existing correlation of observed OD crack angle to project internal degradation.

The staff also noted that continuing confirmation testing will need to be conducted through the end of the period of extended operation in order to either (a) demonstrate that the nature (e.g., plug-like vs. layer-like) and rate of degradation continue as they have in the past and, therefore, can be managed by the program, or (b) demonstrate, through trending, the need to replace the susceptible components prior to signs of external leakage. Plug-like dealloying occurs in a local area where the surrounding area is usually unaffected, whereas layer-like dealloying affects a much broader circumferential and axial area. In its consideration of this continuing testing, the staff noted the long period of time before the renewed license will expire, the importance of the ECW system, and the fact that further degradation will continue to occur. The staff determined that, for PEs, 100 percent of leaking components should be tested/examined until the end of the period of extended operation. In this regard, by letter dated December 18, 2012, the staff issued RAI B2.1.37-5, Part (b), requesting that the applicant amend the AMP, UFSAR Supplement, and commitments to reflect its planned number of continuing confirmation tests.

The basis for accepting 22 PEs as providing reasonable assurance that the flaw size correlation will conservatively project internal degradation is based on a 90/90 sampling methodology, as obtained from Sandia National Laboratory Report SAND 2010-0550, “Sample Sizes for Confidence Limits for Reliability” (February 2010), Table 1, “Required Sample Size for Various Population Sizes for 90% confidence for 90% Reliability with No Failures in the Sample, Sampling without Replacement.” The 90/90 sampling basis is consistent with other GALL Report AMPs (e.g., XI.M32, “One-Time Inspection,” XI.M33, “Selective Leaching”).

The number of exams described above is based on the test outcomes supporting current design documents, such as the correlation of OD crack angle to internal degradation and material properties remaining above those assumed in the structural integrity analyses. If any of these tests do not support the pertinent design output documents, further testing will be required. The testing to establish reasonable assurance will have to be completed and submitted to the staff prior to issuance of the final SER.

The staff determined that the wording of the commitments (i.e., Nos. 39, 44, and 45), UFSAR supplement, and AMP is not clear in relation to testing and inspection of removed components (e.g., Commitment Nos. 39 and 45 overlap in their descriptions of examinations). The staff recognizes that different terminology might be established for the above tests and inspections in order to best communicate the program requirements. However, given the currently proposed language in the AMP, UFSAR supplement, and commitments, the staff does not believe that testing and inspection requirements will be correctly interpreted in the future. In this regard, by letter dated December 18, 2012, the staff issued RAI B2.1.37-5, Part (a), requesting that the applicant amend the AMP, UFSAR supplement, and commitments to clearly state the intent of each test and the parameters that will be inspected or tested.

Detecting Degree of Dealloying. The applicant has not provided a sufficient basis to demonstrate how it determines the degree of dealloying of PE specimens. The response to RAI B2.1.37-4, issue 3, "[d]escribe how the percentage of dealloying is identified when testing specimens," did not account for areas where dealloying has penetrated through-wall but has not progressed to completion (i.e., significant depletion of aluminum). While the AMP, UFSAR supplement, and commitments state that samples will be tested for chemical composition including aluminum, it is not clear how this data will be used in conjunction with determining the degree of dealloying. The degree of dealloying is an input parameter to the "monitoring and trending" program element. If the degree of dealloying is not accurately determined, the applicant will not be able to effectively trend material properties through the period of extended operation.

There are many references to 100 percent dealloyed tensile properties throughout the analyses credited by the program. The staff could not conclude that the tensile properties were obtained from specimens that were 100 percent dealloyed from both a dimensional (i.e., percent through-wall) and chemical composition (i.e., aluminum depletion) basis. Table 2.5, "Tensile Test Results on Dealloyed Samples of CA-954 Material from Fittings," of South Texas letter ST-HL-AE-2748, "Failure Analysis and Structural Integrity of Leaking Small Bore Aluminum Bronze Cast Valve Bodies and Fittings in the ECW System," provides a compilation of test sample tensile values and the percent dealloyed. A footnote to the percent dealloyed column of this chart states, "[b]ased on SCM of tensile fracture surface." The staff does not know what "SCM" stands for, and no other criterion for the percent dealloyed values is stated in the document.

The staff believes that, if the degraded components that are tested are not 100 percent dealloyed from both a dimensional and a chemical composition basis, the material properties obtained from those tests may not represent the lowest possible values. Therefore, the program needs to document how partially dealloyed material property results will be integrated into trending data.

In this regard, by letter dated December 18, 2012, the staff issued RAI B2.1.37-5, Part (d), requesting that the applicant:

- provide a description of "SCM testing," as referenced in Table 2.5 of ST-HL-AE-2748, and explain what criteria were used to establish the percent dealloyed from this testing
- provide a copy of any other testing results that correlate tensile properties to percent dealloying based on both a dimensional (i.e., percent through-wall) and a chemical composition (i.e., aluminum depletion) basis, if available
- state how the percentage dealloying will be determined from a dimensional and chemical composition basis for testing being conducting in the future
- state how partially dealloyed material properties will be integrated into trending data

Structural Integrity Analytical Method. The applicant has not provided a sufficient basis to demonstrate that, upon detection of dealloying, the impacted component has structural integrity (i.e., the ability of a structure or a component to withstand a designed service load) such that it will be capable of performing its intended function(s) consistent with the CLB for the period of extended operation. During the staff's audits and subsequent evaluation of this program, the staff reviewed several calculations that were intended to demonstrate structural integrity of impacted components that had been partially or fully dealloyed. The applicant's analysis is documented in APTECH Report AES-C-1964-1, “Calculation of Critical Bending Stress for Dealloyed Aluminum-Bronze Castings in the ECW System.” This calculation conducted linear elastic fracture mechanics analyses and limit load (net-section plastic collapse) analyses to demonstrate that a degraded component would not fail by fracture or plastic collapse. The analysis methods were based on ASME Code Section XI for flawed piping. Each size component (3 in. to 30 in. outer diameter) was analyzed for a range of dealloying and crack angles. The output was a series of figures, which plotted critical bending stress vs. dealloyed or crack angle. The applicant uses these output curves to determine whether the component meets structural integrity requirements by reviewing the pipe stress output data for the location and the assumed internal flaw size based on the flaw size correlation discussed earlier. The output curves are a critical basis for the “acceptance criteria” program element.

The staff finds the analysis method to be acceptable based upon a review of the calculation and ASME Code Section XI, Appendix H, “Evaluation Procedures for Flaws in Piping Based on the Use of a Failure Assessment Diagram.” However, the fracture toughness properties were obtained from APTECH Report AES-C-1630-2, “Calculation of Critical Bending Stress for Flawed Pipe Welds in the ECW System,” which references an earlier document, APTECH 8303381, “Structural Integrity Analysis of Essential Cooling Water Lines (South Texas Project).” Based on a review of Table 4-4, “Summary of Mechanical Test Results,” from APTECH 8303381, the staff determined that the fracture toughness test specimens were not fully dealloyed. In addition, based on a review of AES-C-1964-1, Section 4.2, “Flow Stress,” yield strength properties were not obtained from dealloyed specimens. The staff noted that, based on a review of South Texas letter ST-HL-AE-2748, “Status of Corrective Actions in the ECW System,” Table 2.5, “Tensile Test Results on Dealloyed Samples of CA 954 Material from Fittings,” ultimate tensile properties were obtained from dealloyed specimens. Given that fracture toughness and yield strength were not obtained from dealloyed specimens, the staff cannot find the structural integrity analyses to be adequate to demonstrate structural integrity.

As described above, during the public meeting conducted on August 27, 2012, the applicant proposed that the structural integrity analyses could be acceptable by either obtaining dealloyed material properties or by empirical testing (i.e., conducting a sufficient number of proof tests on dealloyed specimens). It should be noted that, as of the time that this SER was prepared, the applicant had not formally stated that it will pursue the alternative path of obtaining dealloyed material properties. Therefore, this evaluation is based on using empirical methods to demonstrate the adequacy of the structural integrity analytical method. APTECH Report AES-C-1964-4, “Evaluation of 6-inch Flange Test,” documents the results of a pressure and a three-point bend test on a significantly dealloyed flange (i.e., circumferentially dealloyed to a depth of 35-90 percent of the wall thickness), which also had a through-wall 180 degree crack and a part through-wall 330 degree crack. The results of the bend test demonstrated a 20 percent margin above the strength predicted by the structural integrity analysis. Based on the staff’s review of AES-C-1964-4, the staff concluded that this test could be considered as an analysis confirmatory test (ACT); however, a single test is insufficient to accept the methodology for all component and flaw sizes through the period of extended operation. The staff determined that an additional eight ACTs would be required to establish a reasonable basis that the structural integrity analysis methodology conservatively predicts the strength of degraded components, such that the applicant could successfully age manage those components. The staff determined that the ACTs should include a sufficiently wide range of component sizes and flaw sizes (internal crack angles) to validate the analytical methodology. Specifically, a minimum of three component sizes, with three tests in each size to span a range of crack angles, is recommended. This testing to establish reasonable assurance that the structural integrity analyses will provide appropriate acceptance criteria to the “acceptance criteria” program element will have to be completed and submitted to the staff prior to issuance of the final SER.

The staff determined that nine successful tests, including a minimum of three component sizes with three tests in each size, will be sufficient to demonstrate that the structural integrity analyses are valid for the following reasons:

- The analysis is based upon ASME Code Section XI methods appropriate to the defect characteristics.
- The structural analysis output curves follow generally accepted trends (i.e., higher critical bending stress corresponds to lower flaw tolerance).
- Nine test points would demonstrate acceptability across both component and flaw sizes.
- Only test specimens that are sufficiently dealloyed will be used for ACTs, as explained below in the discussion regarding RAI B2.1.37-5, Part (c).
- The outcome of the nine tests will either support the current design output curves or further testing will be required.

The response to RAI B2.1.37-4 did not address the minimum level of degradation (e.g., degree of dealloying) that a component must exhibit in order to be used as an ACT specimen. The degree of dealloying in a tested component must be sufficient so that its material properties (e.g., fracture toughness, yield strength) are representative of an advanced degree of dealloying. Therefore, some removed leaking components may not be acceptable specimens for validating the analytical methodology. An example would be a specimen that had a very narrow angle of through-wall dealloying and minimal layer-like dealloying around the entire circumference. In this regard, by letter dated December 18, 2012, the staff issued RAI B2.1.37-5, Part (c), requesting that the applicant state and justify the minimum level of degradation that a component must exhibit in order to be used as an appropriate test specimen for ACTs.

The staff acknowledges the long period of time before the renewed license would expire, the importance of the ECW system, and the fact that further degradation will continue to occur. As such, the staff determined that the applicant will need to conduct continuing confirmation testing throughout the period of extended operation. The staff determined that, in regard to ACTs, upon completion of the nine tests, the applicant should test 20 percent of leaking components until the end of the period of extended operation. The 20 percent sampling basis is consistent with sampling-based GALL Report AMPs (e.g., XI.M32, “One-Time Inspection,” XI.M33, “Selective Leaching”). As is the case with PEs, in this regard, by letter dated December 18, 2012, the staff issued RAI B2.1.37-5, Part (b), requesting that the applicant amend the AMP, UFSAR supplement, and commitments to reflect the recommended number of continuing confirmation tests discussed above or to provide a statistical or engineering judgment basis for using an alternative number of tests.

The staff noted that, just as for PEs, the wording of the commitments (i.e., Nos. 39, 44, and 45), UFSAR supplement, and AMP is not clear in relation to testing and inspection of removed components. For example, Commitment No. 45 states that fracture toughness testing will be conducted, but it does not discuss pressure and bend testing. The staff determined that ACTs should consist of pressure testing and bend testing, and these samples should also be tested/inspected for chemical composition (including aluminum content), mechanical properties, microstructure, degree of dealloying, and cracking. In this regard, by letter dated

December 18, 2012, the staff issued RAI B2.1.37-5, Part (a), requesting that the applicant revise the AMP, UFSAR supplement, and commitments to clearly state the intent of each ACT test and the parameters that will be inspected or tested.

Specific Analytical Input Values. The staff has the following questions regarding how the results of the inspections described in the "detection of aging effects" program element are effectively evaluated by the methods described in the "acceptance criteria" program element.

- In the external/internal flaw size correlation in AES-C-1964-5, the observed OD crack angle is used to derive an average through-wall dealloying angle. However, the critical bending stress curves in AES-C-1964-1 (the output of the analytical calculations) use a crack angle, not an average through-wall dealloying angle. The staff lacks sufficient information to be able to understand the link between the flaw size correlation and its use in the critical bending stress curves. The staff noted that the response to RAI B2.1.37-4, enclosure 1, page 3 of 9, incorrectly characterizes the correlation when it stated that, "[t]he examination results were used to establish a correlation between length of a flaw on the outer diameter and the size of any internal crack and the extent of the dealloyed region of the component."

  Also, it is not clear to the staff why an average angle would be used when the dimensions of the flaw on the inside pipe surface are used in Figures C-2200-1, "Flaw Characterization-Circumferential Flaws," and C-4310-1, "Circumferential Flaw Geometry," of ASME Code Section XI, and Figure 5-1, "Circumferential Flaw Geometry—Net Section Collapse Model," of AES-C-1964-1.

  The staff plotted the OD and inside diameter (ID) crack and dealloying angle data from Section 4.1, "Metallurgical Data," of AES-C-1964-5 (i.e., dealloyed OD vs. dealloyed ID and crack OD vs. crack ID). Two crack data points and three dealloying data points fell outside of the correlation in a non-conservative manner (i.e., the correlation under-predicted the size of the internal degradation). It is not clear how the applicant derived its correlation curve in regard to these points.

  If it is not appropriate to use an average through-wall dealloying angle, a new correlation using inside dimensions will need to be developed. The staff lacks sufficient information to understand whether such a new correlation could affect the structural integrity determination of recently degraded components, and by extension, degraded components discovered during the period of extended operation.

- The wording of the response to Part (e) of RAI B2.1.37-3 is not clear on what minimum structural (e.g., safety) factor will be used for the normal/upset conditions and emergency and faulted conditions when a structural integrity calculation is performed on a component with a newly-discovered indication.
- It is not clear to the staff how external dimensions of the indication are sized. For example, when an indication consists of a crack within a larger dealloyed region, it is not clear which feature is measured. Also, it is not clear how a singular rounded (surface) indication, or multiple in-line rounded (surface) indications, are characterized.
- It appears that, based on the external dimensions of the flaw, an average flaw angle is developed based on the AES-C-1964-5 correlation and used as input into the critical bending stress analyses in AES-C-1964-1, regardless of whether the through-wall degradation is dealloying with no crack, a part-through crack with dealloying, or

through-wall crack with dealloying. However, based on the staff's review of several relief requests submitted by the applicant since dealloying was first detected, it is not clear that the applicant consistently assumed that internal cracks are present in the dealloyed region or that the cracks could be as large as the entire dealloyed region. Given that cracks have been observed in dealloyed regions of degraded components as documented in AES-C-1964-5 and volumetric examinations are not conducted when degraded components are inspected, the staff concluded that a fully developed crack should be assumed to be present in the dealloyed region when comparing the as-found inspection results to the criteria in the "acceptance criteria" program element.

- Given the ambiguities between the calculations, it is not clear to the staff that the steps in a structural integrity determination of a degraded susceptible aluminum bronze component in the ECW system can be consistently interpreted without a procedure. In addition to the ambiguities, based on plant-specific operating experience, consistent performance is also challenged since these evaluations are conducted infrequently.

In this regard, by letter dated December 18, 2012, the staff issued RAI B2.1.37-5, Part (f), requesting the following information:

- Explain why an average through-wall dealloying angle is the output of the correlation in AES-C-1964-5, rather than the inside wall dimension.
- Explain how the correlation from AES-C-1964-5 will be modified if use of the average dealloying angle is not appropriate. Additionally, reconsider the structural integrity evaluation for any degraded components discovered since 2011 and state whether the components would still be considered to meet structural integrity criteria (using this modified correlation) and, therefore, would still be capable of performing their intended function(s) consistent with the CLB for the period of extended operation with the new correlation.
- Clarify whether the structural factor for the normal/upset conditions will always be at least 2.77 and, for emergency and faulted conditions, at least 1.39 (as suggested in response to RAI B2.1.37-3, Part (e)). If not, state what the minimum structural factors would be and the basis for the values being less than those stated in ASME Code Section XI.
- Regarding the following four example scenarios of OD-observed degradation:
    - four small rounded indications of through-wall dealloying located in a circumferential axis at 10:00, 11:00, 1:00, and 2:00 on a 10-in. flange
    - one indication at 10:00, 0.5-in. long, with what appears to be rounded ends and no measurable width on a 4-in. flange
    - one "greenish" stain of approximately 0.125-in. diameter at the 10:00 position on a 6-in. flange
    - one crack-like indication, 0.5-in. long, within a larger greenish stain with a circumferential length of 1 in.

    The staff requested that the applicant provide the following details/results based on its field observation/structural integrity determination methodology:

    - the size of the OD flaw

- the corresponding size of the internal flaw that would be used in the structural integrity determination
- which structural integrity output figure would be used from AES-C-1964-1
- the stress component input values that would be used from the highest stress location in the ECW system with susceptible components for that size as obtained by the stress analyses on record and how they would be combined in the structural integrity determination
- what structural factor will be used
- the critical bending stress as derived from the figures in AES-C-1964-1 whether the component would be considered to be capable of meeting its intended function consistent with the CLB for the period of extended operation

This scenario-based information will provide the staff with insights as to how the applicant will evaluate the results of the inspections described in the "detection of aging effects" program element against the parameters described in the "acceptance criteria" program element.

- Explain what site procedure provides the step-by-step instructions for determining the structural integrity of a degraded susceptible aluminum bronze component in the ECW system. If no such procedure is currently used, state the basis for why the absence of written instructions is acceptable.

Acceptance Criteria. While the revised AMP, enhancements, UFSAR supplement, and commitments describe acceptance criteria for tensile, yield, and fracture toughness properties, the RAI responses do not describe specific follow-on actions that would be taken if abnormal test or inspection results are obtained, beyond stating that results would be trended, an engineering evaluation would be performed, or that the condition will be documented in the Corrective Action Program. The acceptability of the Selective Leaching of Aluminum Bronze plant-specific AMP will be based upon (a) either empirical testing results or attainment of dealloyed material properties to be used in revised structural integrity analyses, and (b) the continuing demonstration of the ability to detect aging using external visual inspections prior to the degradation adversely impacting the ability of a susceptible component to perform its intended function consistent with the CLB for the period of extended operation.

The staff notes the possibility that results of the tests and inspections could invalidate the analytical assumptions to such an extent that structural integrity could not be reasonably expected to be demonstrated for leaking components, or that an in-situ leaking fitting could be found that cannot be shown to meet structural integrity requirements.

In either case, given that the applicant has stated that there are approximately 350 susceptible components, it would be unreasonable to assume that only the tested or in-situ component was not capable of meeting its intended function; therefore, the basis of the aging management approach (i.e., using external visual inspections to detect degradation prior to adversely impacting the ability of a susceptible component to perform its intended function consistent with the CLB for the period of extended operation) would be invalidated.

Given that PEs and ACTs will continue to be conducted throughout the period of extended operation, the "acceptance criteria" program element needs to include specific criteria for several different potential outcomes of the testing. By letter dated December 18, 2012, the staff issued RAI B2.1.37-5, Part (e) requesting that the applicant (a) state what specific actions will be taken and the basis for those actions, and (b) amend the AMP, UFSAR Supplement, and Commitments to state the specific actions for the following six example scenarios:

(1) During a PE or ACT, a crack or degree of dealloying is discovered outside of the current correlation as shown on page 12 of AES-C-1964-5. It is unclear to the staff whether a new correlation curve will be developed and whether existing leaking components will be reanalyzed with the new correlation. In RAI B2.1.37-5, Part (e), the staff also requested that the applicant state how many additional fittings would be immediately examined, even though not leaking, to determine whether this result was a singular data point or whether there are many more susceptible fittings that are experiencing dealloying in a manner that would not be expected to fall within the flaw size correlation (i.e., predominately layer-type dealloying) or state the basis for not expanding the inspection scope.

(2) An ACT test result yields a data point below that predicted by the size-appropriate structural integrity analysis (e.g., the curve in Figure 4-2, “Evaluation of Flange Bend Test Results,” in AES-C-1964-5). It is unclear to the staff whether the analytical methodology will be revised to reflect the lower data point. For example, if it is suspected that the lower data point occurred because an appropriately low fracture toughness value was not used, it is unclear whether the fracture toughness value in the calculation would be decreased until the curve is sufficiently shifted. Also, it is unclear whether existing leaking components will be reanalyzed with the revised methodology.

(3) The in-situ evaluation of a newly discovered leaking fitting (i.e., the fitting has not yet been removed from service) results in a determination that the degraded component is not operable. It is unclear to the staff what this result would cause the applicant to conclude in regard to the effectiveness of the program to age-manage the remaining susceptible components and whether a new technical basis will be established for the program.

(4) PE or ACT results demonstrate a trend where, due to continuing dealloying, tensile strength, yield strength, or fracture toughness properties are projected to be below the acceptance criteria prior to the end of the period of extended operation.

(5) PE or ACT results demonstrate that layer-type dealloying is becoming predominant over plug-type, such that it is no longer possible to project internal degradation based on external observations. The staff recognizes that there is some level of layer dealloying occurring in most fittings, as illustrated in Figure 3-1, “Typical Dealloying/Cracking Cross Sections,” of AES-C-1964-5. However, the through-wall dealloying of the samples inspected in 1994 demonstrated a plug-like nature, and a correlation of OD crack angle to internal degradation was able to be reasonably established on that basis. In RAI B2.1.37-5, Part (e), the staff also requested that the applicant state (a) the maximum percent of cross-sectional layer-type dealloying that will be accepted and justify the acceptance criterion and (b) the step-by-step process an examiner uses when conducting profile exams to determine the transition point between layer-type and plug-type dealloying and thereby derive the internal dealloying angle.

(6) PE or ACT results demonstrate that cracking has extended into the un-dealloyed region. AES-C-1964-5 Section 3.0, “Method of Approach,” and Section 5.0, “Significance of Part-Through Cracks,” assume that cracking does not extend into the un-dealloyed portion of a component. Although, under this scenario, the specific component that had cracking extending into the un-dealloyed portion would have already been replaced, any

one or more of the hundreds of susceptible fittings could potentially have cracking of this nature. .

The staff noted that the applicant's program established the tensile material property acceptance criterion as an average value, rather than a minimum value, equal to or greater than 30 ksi. However, the calculations are based on a tensile value of 30 ksi; therefore, the acceptance criterion could result in components with tensile properties below 30 ksi being found acceptable. By letter dated July 26, 2012, the staff issued RAI B2.1.37-4, Part (7), requesting the applicant to amend the applicable portions of the LRA to reflect that the acceptance criterion of ultimate tensile strength is a minimum of 30 ksi or state the basis as to why using an average value is acceptable.

In its response dated October 4, 2012, the applicant stated that LRA Sections A1.37 and B2.1.37 and Commitment Nos. 39 and 44 in Table A4.1 were revised to reflect that the acceptance criterion of ultimate tensile strength value of aluminum bronze material is equal to or greater than 30 ksi. This acceptance criterion is also provided in new Commitment No. 45.

The staff finds the applicant's response acceptable because the program's acceptance criterion for tensile strength is consistent with the analytical basis. The staff's concern described in RAI B2.1.37-4, Part (7), is resolved.

Components of 1-Inch NPS and Smaller. The "scope of program" and "parameters monitored or inspected" program elements of the Selective Leaching of Aluminum Bronze Program state that, "[c]omponents greater than one-inch will be replaced by the end of the subsequent refueling outage." The staff noted that UFSAR Section 9A, "Assessment of the Potential Effects of Through-Wall Cracks in ECWS Piping," states, in part, that relief requests are submitted when leaks are identified except for, "leaks in lines 1 inch or under which are exempt from ASME Code Section XI replacement rules." The staff cannot find a basis for allowing repairs to 1-inch NPS and smaller components to be delayed beyond the subsequent refueling outage. In this regard, by letter dated December 18, 2012, the staff issued RAI B2.1.37-5, Part (g), in part, to request that the applicant state the basis for not replacing 1-inch NPS and smaller components by the end of the subsequent outage. The staff also requested that the applicant state the basis for why the effects of aging for 1-inch NPS and smaller components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB prior to replacement.

Leakage Detection for Buried Components. LRA Section B2.1.37 states that the program includes periodic yard walkdowns in the vicinity of the buried piping with aluminum bronze welds (the only susceptible buried material) to look for changes in ground conditions that would indicate leakage. 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 its intended function(s) consistent with the CLB for the period of extended operation.

During the staff's 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 down 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 ft 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; however, a perforated pipe leading to a nearby catch basin was installed between the building floor slab and the piping.
- The detectable leakage rate of 10 gpm is 1 percent of the allowable leakage from the system and would affect a wide area.
- 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.
- Detectable leak size (10 gpm) is 1 percent of the allowable leakage rate from the piping (1000 gpm); 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 can be detected 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.

Therefore, the buried piping will be adequately age-managed so that the intended function(s) will be maintained consistent with the CLB throughout the period of extended operation. The staff's concern described in RAI B2.1.37-2, Part (5), is resolved.

RAI B2.1.37-3, Part (g), requested that the applicant propose a sampling program of sufficient size to confirm the extent of further dealloying or crack propagation and revise LRA Sections A1.37, B1.37, and Commitment No. 39 accordingly. In relation to the buried pipe portion of susceptible components, the applicant's response stated that it will continue to use the existing monitoring plan (inspections for indications of leakage on ground surfaces) and not remove samples for testing because the formation of a continuous dealloying-susceptible gamma-2 phase was unlikely, based on the following reasoning. The buried pipe aluminum content varies between 6.16 percent and 7.96 percent with a minimum iron content of 2.2 percent. The weld filler material aluminum content varies between 9.06 percent and 9.55 percent with minimum iron content between 0.6 and 0.8 percent. Applying the highest aluminum content and lowest carbon content, and expected composition of the base metal weld metal puddle, a weld deposit of 9.07 percent aluminum and 1.08 percent carbon is obtained. A 9.1 percent aluminum content alloy would require the welded zone to remain at 400-900 °C for 7 minutes for the gamma-2 phase to form. It is unlikely that the components will remain in this temperature range long enough to form a continuous phase of gamma-2. The staff finds the applicant's response—that it will continue to use the existing monitoring plan and not remove samples for testing—acceptable because the applicant demonstrated that it is unlikely that there is a significant continuous phase of gamma-2 material, no buried piping welds have leaked to date, and there is significant margin 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. The staff's concern related to buried piping in RAI B2.1.37-3, Part (g), is resolved.

Flooding, Reduction in Flow and Water Losses for the Essential Cooling Pond (ECP). During the staff's audits and subsequent evaluation of this program, the staff reviewed calculations and UFSAR Appendix 9A. The staff could not determine whether the USFAR Appendix 9A flooding, reduction in flow, and water loss from the ECP analyses envelop the potential degradation that could occur during the period of extended operation. The staff noted that the applicant has not provided any information which justifies why the medium-energy break size flaw stated in UFSAR Appendix 9A (i.e., a slot one-half the pipe diameter long and one-half the pipe wall thickness wide) is larger than the maximum size flaw for which the piping can still perform its intended function during normal operation. The staff also noted that, in this case, a flaw could be determined to be of acceptable size (i.e., small enough such that the pipe could still perform its intended function); however, flooding, reduction in flow, and water loss criteria could be challenged if the acceptable flaw size was larger than the assumed medium-energy break size flaw. By letter dated April 12, 2012, the staff issued RAI B2.1.37-3, Part (h), requesting, in part, that the applicant state the basis for why only one component with a through-wall defect, and not multiple components, is acceptable in analyzing the impact of flooding reduction in flow and water loss from the ECP.

In its response dated May 31, 2012, the applicant stated the following:

> When analyzing the impact of flooding, reduction in flow, and water loss from the essential cooling pond, the cumulative impact of multiple through-wall flaws is considered for the operability evaluation of the ECW system. The total leakage rate is considered. If it occurs through multiple wall flaws, the combined total leakage rate is evaluated. Compensatory actions are taken as necessary to maintain operability if the flaws are not repaired within the allotted time frame. ECW system leakage associated with dealloying is a slowly developing process. Above ground leaks would be detected almost immediately and would not be allowed to progress to the medium energy break size flaw assumed in the flooding analysis or progress to the critical crack size that could compromise structural integrity of the pipe.

The staff finds that the portion of RAI B2.1.37-3, Part (h) addressing leakage from more than one component is acceptable because, (a) given the slow-growing nature of selective leaching and the decreasing trend in leaks, the likelihood of multiple components (i.e., more than two or three) leaking at the same time is low, based on the staff's analysis of the leakage data contained in Table 1, "ECW De-alloying Data," submitted by the applicant in letter dated December 8, 2011,and (b) the applicant addresses the cumulative impact of multiple through-wall flaws when it conducts operability evaluations for each leak in the ECW system. However, the applicant did not provide sufficient information to resolve the staff's question related to the medium-energy break size flaw stated in UFSAR Appendix 9A. By letter dated July 26, 2012, the staff issued RAI B2.1.37-4, Part (5), requesting that the applicant provide the basis for why the medium-energy break size flaw stated in UFSAR Appendix 9A is larger than the maximum acceptable flaw size determined in the structural integrity analyses as related to flooding, reduction in flow, and water loss from the ECP analyses. Additionally, given the maximum leak rate that could occur upstream of any individual component supplied by the ECW system, the staff asked that the applicant state whether the affected component could still perform its intended function consistent with the CLB for the period of extended operation. In its response dated October 4, 2012, the applicant stated:

> STPNOC will determine leak rates that could occur upstream of any individual component supplied by the ECW system. This should validate that the maximum size flaw for which the piping can still perform its intended function does not exceed the medium energy break size flaw stated in UFSAR Appendix 9A flooding, reduction in flow, and water loss from the essential cooling pond assumptions. A summary of the results of these calculations will be submitted to the NRC for review. See new Commitment 46.

The staff requires the results of the leak rate analysis, stated in Commitment No. 46, to complete its evaluation of this issue.

Trending of Material Properties. The staff noted that fracture toughness and yield strength properties are not listed in the program as being trended. In addition, given that the progression rate of dealloying, although slow, could change with time, the staff believes that prevalence of dealloying should be trended in order to determine whether more frequent samples should be obtained. By letter dated July 26, 2012, the staff issued RAI B2.1.37-4, Part (6), requesting that the appropriate portions of the LRA be amended to trend fracture toughness values, yield strength values, and the degree of dealloying in addition to ultimate tensile strength.

In its response dated October 4, 2012, the applicant stated that, in addition to trending ultimate tensile strength, it will revise the LRA to trend the degree of dealloying. The applicant also stated that, as discussed during the public meeting, fracture toughness and yield strength properties would not be trended since trending did not provide additional value for validating the structural integrity analysis.

The staff finds the applicant's response acceptable because LRA Sections A1.37, B2.1.37, and Commitment No. 44 were amended to include trending of the degree of dealloying and the degree of cracking. The staff concurs with the applicant's position that fracture toughness and yield strength need not be trended because the acceptability of the program will be demonstrated by empirical testing as opposed to demonstrating by analysis using dealloyed properties. In addition, yield strength should follow tensile material properties (which will be trended). The staff's concern described in RAI B2.1.37-4, Part (6), is resolved.

Acceptable Program Elements. The staff has confirmed that the following program elements meet the criteria stated in SRP-LR Appendix A; therefore, the staff finds them acceptable.

Scope of Program. 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) pumps, piping welds, and valve bodies exposed to raw water within the scope of license renewal.

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 SCs, 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 finds the applicant's "scope of program" program element to be adequate because the applicant has provided information that clearly identifies the scope of components, materials, and environments covered by the program.

Based on its 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.

Preventive Actions. LRA Section B2.1.37 states that the Selective Leaching of Aluminum Bronze Program does not prevent degradation due to aging effects. The LRA also states that the Open-Cycle Cooling Water Program uses an oxidizing biocide treatment (sodium hypochlorite and sodium bromide) to reduce the potential for microbiologically influenced corrosion (MIC). The staff noted that MIC can provide an initiating site for selective leaching; therefore, the applicant's use of an oxidizing biocide treatment can minimize the potential for selective leaching of aluminum bronze components. However, these preventive actions are not within the scope of the Selective Leaching of Aluminum Bronze Program.

The staff reviewed the applicant's "preventive actions" program element against the criteria in SRP-LR Section A.1.2.3.2, which state that if the program is not a preventive or mitigation program, the information need not be provided.

The staff finds the applicant's "preventive actions" program element to be adequate because the applicant has provided information that clearly identifies the program as being a Condition Monitoring Program only, with no preventive actions needing description.

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; therefore, the staff finds it acceptable.

Program Elements with Open Items: Based on its review of the application and review of the applicant's response to RAIs, the staff lacks sufficient information to confirm that the "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements satisfy the criteria defined in SRP-LR, Appendix A. This issue is being tracked as part of OI 3.0.3.3.3-1.

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 acceptance criteria in SRP-LR Section A.1.2.3.10, which 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 letter dated September 21, 2011, the staff issued RAI B2.1.37-1, Part (2), 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 response dated December 8, 2011, 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 the station. 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), is resolved. However, given that additional through-wall degraded components have been found since the applicant's response to RAI B2.1.37-1, Part (2), by letter dated December 18, 2012, the staff issue issued RAI B2.1.37-5, Part (g), requesting that the applicant update Table 1 of the response to RAI B2.1.37-1 to reflect leaking components that have occurred since July 28, 2011.

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 found 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 does 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 this is the case, 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.

Based on its review of the application and the applicant's response to RAIs, the only remaining open question related to operating experience is associated with RAI B2.1.37-5, Part (g), in which the staff requested that the applicant update Table 1 of the response to RAI B2.1.37-1 to reflect leaking components that have occurred since July 28, 2011. The staff will not complete its review of the "operating experience" program element until it has reviewed all appropriate plant-specific operating experience up to the submission of the PE and ACT results because the new operating experience could have bearing on the effectiveness of the proposed aging management program.

Based on its review of the application and applicant's response to the RAIs, the staff lacks sufficient information to conclude that all applicable plant-specific and industry operating experience related to the Selective Leaching of Aluminum Bronze plant-specific program has been incorporated into the program such that it can be demonstrated that the effects of aging on SSCs within the scope of the program will be adequately managed. The staff's concern related to the "operating experience" program element is being tracked as part of OI 3.0.3.3.3-1.

UFSAR Supplement. 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, as described above for OI 3.0.3.3.3-1, the staff requires further information in order to complete its evaluation of the supplement's consistency with the recommended description in SRP-LR Table 3.0-1.

Conclusion. On the basis of its technical review of the applicant's Selective Leaching of Aluminum Bronze Program, the staff finds that it requires further information to complete its determination 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. The staff also reviewed the UFSAR supplement for this AMP; however, the staff requires further information to complete its determination that the UFSAR supplement for this AMP provides an adequate summary description of the program. The staff's issues are documented in OI 3.0.3.3.3-1.

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 D 5163-08, "Establishing Procedures to Monitor the Performance of Coating Service Level I Coating Systems in an Operating Nuclear Power Plant," and RG 1.54, "Service Level I, II, and II Protective Coatings Applied to Nuclear Power Plants," Revision 2, 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 D 5498, "Standard Guide for Developing a Training Program for Personnel Performing Coating Work Inspection for Nuclear Facilities."

Staff Evaluation. The staff reviewed program elements one through six of the applicant's program against the acceptance criteria for the corresponding elements, as stated in SRP-LR Section A.1.2.3. The staff's review focused on how the applicant's program manages aging effects through the effective incorporation of these program elements. The staff's evaluation of each of these 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.

Scope of Program. 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.

Preventive Actions. 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, which state that some condition or performance monitoring programs do not rely on preventive actions; thus, this information need not be provided.

Based on the review of the application, the staff confirmed that the "preventive actions" program element satisfies the criteria defined by SRP-LR Section A.1.2.3.2; therefore, the staff 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 D 5163). 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 D 5163-08 and RG 1.54, and coating inspections are conducted during every refueling outage. The staff noted that the program uses ASTM D 5163 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 D 5163 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 “parameter 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 due to 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.outage The applicant also stated that personnel qualifications, inspection plans, inspection methods, and inspection equipment are consistent with the requirements in ASTM D 5163. The applicant stated that destructive and non-destructive 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 D 7108-05, “Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist.” Furthermore, the applicant indicated that the Coatings Inspector is certified in accordance with ASTM D 5498. Both ASTM D 7108 and D 5498 are called out in ASTM D 5163, 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 to be 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 since the staff has found it acceptable that visual inspections are performed and are able to detect for 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 D 5163. 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 since degraded coatings assessed for repairs are made in accordance with ASTM D 5163. The staff considers ASTM D 5163 acceptable since 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 defined 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.

In a 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 Corrective Action Program.
- 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 D 5498 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 non-destructive tests are performed by individuals trained in applicable referenced standards of ASTM D 5498 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 has appropriately identified defective or deficient coatings in accordance with ASTM D 5163, 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.

Operating Experience. 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, which resulted in the issuance of RAI B2.1.39-2. 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.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 D 5163. In addition, the applicant has 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 has 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 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)(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).

3.0.4 Quality Assurance Program Attributes Integral to Aging Management Programs

3.0.4.1 Summary of Technical Information in the Application

In Appendix A, "Final Safety Analysis Report Supplement," Section A1, "Summary Descriptions of Aging Management Programs," and Appendix B, "Aging Management Programs," Section B1.3, "Quality Assurance Program and Administrative Controls," of the LRA, the applicant described the elements of corrective action, confirmation process, and administrative controls that are applied to 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. Appendix B, Section B1.3, of the LRA 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 Appendix B, Section B1.3, of the LRA 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 Appendix B of the LRA, 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 and MSS 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 Appendix A, Section A1, and Appendix B, Section B1.3, of the LRA—are consistent with the staff’s position regarding QA for aging management.

3.0.4.3 Conclusion

On the basis of the staff’s evaluation of the descriptions and applicability of the AMPs and their associated quality attributes provided in Appendix A, Section A1, and Appendix B, Section B1.3, of the LRA, 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 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 Corrective Action Program (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. This 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 Operating Experience Program (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), 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 License Renewal Interim Staff Guidance, 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 aging management programs; 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

Consideration of Operating Experience in 10 CFR Part 50, Appendix B, Program. 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.

Sources of Operating Experience. 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 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 Licensee Event Reports 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. The applicant's response dated February 27, 2012, further states that NRC License Renewal Interim Staff Guidance and revisions to the GALL Report were added to the source documents reviewed. 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.

Consideration of All Incoming Plant-Specific and Industry Operating Experience. 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 the CAP complements the OEP to monitor age-related issues. The applicant further states 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 Program to screen operating experience acceptable in this respect because both programs would not preclude the capture of plant-specific and industry operating experience related to aging.

Identification of Operating Experience Related to Aging. 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.

Information Considered in Operating Experience Evaluations. 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 screens plant-specific and industry operating experience documents for applicability and considers 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, orif 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 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 Corrective Action Program event codes to ensure identification of aging-relatedage-related degradation effects
- completing a training "needs analysis" for plant personnel who process operating experience information for aging-relatedage-related effects
- providing criteria for reporting plant-specific operating experience on aging-relatedage-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. As 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 toamend 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 preceed 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 has demonstrated that operating experience will be reviewed on an ongoing basis sothat 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 generatorsgenerator

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 (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 (SER Section 3.1.2.1.1)
Steel; stainless steel; steel with Ni-alloy or stainless steel cladding; Ni-alloy RCPB piping, piping components, and piping elements exposed to reactor coolant (3.1.1.3)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c), and environmental effects are to be addressed for Class 1 components	Yes, TLAA	BWR only	Not applicable to PWRs (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 (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 (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 (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 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 (SER Sections 3.1.2.2.1 and 4.3)
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 (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 (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 (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 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 (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 (SER Section 3.1.2.1.1)
Steel and stainless steel isolation condenser components exposed to reactor coolant (3.1.1.13)	Loss of material due to general (steel only), pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	BWR only	Not applicable to PWRs (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 (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 (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 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	Not applicable to STP—STP has Model Delta-94 SGs, not Model 44 or 51 (SER Section 3.1.2.2.2.4)
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 (SER Sections 3.1.2.2.3.1 and 4.2)
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 (SER Section 3.1.2.2.3.2)
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 (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 (SER Section 3.1.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
RV shell fabricated of SA508-Cl 2 forgings clad with stainless steel using a high-heat-input welding process (3.1.1.21)	Crack growth due to cyclic loading	TLAA	Yes, TLAA	TLAA	Crack growth due to cyclic loading is a TLAA (SER Sections 3.1.2.2.5 and 4.7.4)
Stainless steel and Ni-alloy RVI components exposed to reactor coolant and neutron flux (3.1.1.22)	Loss of fracture toughness due to neutron irradiation embrittlement, void swelling	UFSAR supplement commitment to: (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, but applicant commitment needs to be confirmed.	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.	Consistent with the GALL Report (SER Section 3.1.2.2.6)
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 (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 (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 (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 (3.1.1.26)	Cracking due to cyclic loading	Inservice Inspection (IWB, IWC, and IWD) and plant-specific verification program	Yes	BWR only	Not applicable to PWRs (SER Section 3.1.2.1.1)
Stainless steel and Ni-alloy RVI screws, bolts, tie rods, and hold down springs (3.1.1.27)	Loss of preload due to stress relaxation	UFSAR supplement commitment to: (1) participate in industry RVI aging programs; (2) implement applicable results; and (3) submit for staff approval, > 24 months before the period of extended operation, an RVI inspection plan based on industry recommendation.	No, but applicant commitment needs to be confirmed.	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.	Consistent with the GALL Report (SER Section 3.1.2.2.9)
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 (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 (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 RVI components (e.g., upper internals assembly, rod cluster control assembly (RCCA) guide tube assemblies, baffle/former assembly, lower internal assembly, shroud assemblies, plenum cover and plenum cylinder, upper grid assembly, CRGT assembly, core support shield assembly, core barrel assembly, lower grid assembly, flow distributor assembly, thermal shield, instrumentation support structures) (3.1.1.30)	Cracking due to SCC and IASCC	Water Chemistry and UFSAR supplement commitment to: (1) participate in industry, RVI aging programs; (2) implement applicable results; and (3) submit for staff approval, > 24 months before the period of extended operation, an RVI inspection plan based on industry recommendation.	No, but applicant commitment needs to be confirmed.	Water Chemistry Program and 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.	Consistent with the GALL Report (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 (SER Section 3.1.2.2.13)
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 (SER Section 3.1.2.2.14)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and Ni-alloy RVI components (3.1.1.33)	Changes in dimensions due to void swelling	UFSAR supplement commitment to: (1) participate in industry RVI aging programs; (2) implement applicable results; and (3) submit for staff approval, > 24 months before the period of extended operation, an RVI inspection plan based on industry recommendation.	No, but applicant commitment needs to be confirmed.	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.	Consistent with the GALL Report (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 (SER Section 3.1.2.2.16, item 1)
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 (SER Sections 3.1.2.1.1 and 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
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 (SER Section 3.1.2.2.16.2)
Stainless steel and Ni-alloy RVI components (e.g., upper internals assembly, RCCA guide tube assemblies, lower internal assembly, CEA shroud assemblies, core shroud assembly, core support shield assembly, core barrel assembly, lower grid assembly, flow distributor assembly) (3.1.1.37)	Cracking due to SCC, PWSCC, and IASCC	Water Chemistry and UFSAR supplement commitment to: (1) participate in industry RVI aging programs; (2) implement applicable results; and (3) submit for staff approval, > 24 months before the period of extended operation, an RVI inspection plan based on industry recommendation.	No, but applicant commitment needs to be confirmed.	Primary Water Chemistry Program and ASME Section XI ISI (IWB, IWC, and IWD) Program, including its Commitment No. 1	Consistent with the GALL Report (SER Section 3.1.2.2.17)
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 (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 (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 (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 (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 (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 (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 (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 (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
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 (SER Section 3.1.2.1.1)
Stainless steel and Ni-alloy RVIs exposed to reactor coolant (3.1.1.47)	Loss of material due to pitting and crevice corrosion	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry	No	BWR only	Not applicable to PWRs (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 (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 (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 (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 (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 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 (SER Section 3.1.2.1.4)
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 (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 (SER Section 3.1.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
CASS Class 1 piping, piping components, and piping elements and CRD pressure housings exposed to reactor coolant > 250 °C (482 °F) (3.1.1.57)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS	No	Thermal Aging Embrittlement of CASS Program	Consistent with the GALL Report (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 (SER Section 3.1.2.1.5)
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) (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

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 RV flange, stainless steel and Ni-alloy RVIs exposed to reactor coolant (e.g., upper and lower internals assembly, CEA shroud assembly, core support barrel, upper grid assembly, core support shield assembly, and lower grid assembly) (3.1.1.63)	Loss of material due to wear	Inservice Inspection (IWB, IWC, and IWD)	No	ASME Section XI ISI (IWB, IWC, and IWD) Program	Consistent with the GALL Report
Stainless steel and steel with stainless steel or Ni-alloy cladding pressurizer components (3.1.1.64)	Cracking due to SCC and PWSCC	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
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 (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

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, steel with stainless steel cladding Class 1 piping, fittings, pump casings, valve bodies, nozzles, safe ends, manways, flanges, CRD housing; pressurizer heater sheaths, sleeves, diaphragm plate; pressurizer relief tank components, RCS cold leg, hot leg, surge line, and spray line piping and fittings (3.1.1.68)	Cracking due to SCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry	No	ASME Section XI ISI (IWB, IWC, and IWD) and Water Chemistry programs	Consistent with the GALL Report (SER Section 3.1.2.1.4)
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 (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 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

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 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
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 (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 (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 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 (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 88-2.	No	Not applicable to STP	Not applicable (SER Section 3.1.2.1.1)
CASS RVIs (e.g., upper internals assembly, lower internal assembly, CEA shroud assemblies, CRGT assembly, core support shield assembly, lower grid assembly) (3.1.1.80)	Loss of fracture toughness due to thermal aging and neutron irradiation embrittlement	Thermal Aging and Neutron Irradiation Embrittlement of CASS	No	The PWR Reactor Internals Program is credited to manage loss of fracture toughness of CRGT assembly, BMI instrument column and other CASS RVI components under LRA item 3.1.1.22.	Consistent with the GALL Report (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 (SER Section 3.1.2.1.7)
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 (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; 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 (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 (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
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 (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
- Steam Generator Tube Integrity

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 closed-cycle cooling water 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 closed-cycle cooling water 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 claim 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 closed-cycle cooling 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 components exposed to closed-cycle cooling water 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 claim 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 claim 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 claim 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 claim 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 claim 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 claim 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 are substantial differences in the titles of the AMPs proposed by the applicant and recommended by the GALL Report, 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 has 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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 140 °F threshold for SCC of stainless steel material, and the components in the above stated tables are in an ambient temperature less than 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 140 °F.
- As stated in the GALL Report, Section IX.D, SCC can only occur at ambient conditions (i.e., less than 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 Corrective Action Program.
- 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, describes a safety injection system hot leg check valve on which a seal cap enclosure had been installed in 1997 due to 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).

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 Section A0 of Appendix A of the LRA states that the summary descriptions of license renewal commitments [contained in Section A4] will be incorporated into the STP 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 additional 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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 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 ReactorsReactor 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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.6 Loss of Fracture Toughness Due to Thermal Aging 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 certified material test reports 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 certified material test reports for the materials, and the screening calculation found that the ferrite content of the fittings to be less than 20 percent.

In 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 Loss of Fracture Toughness Due to Thermal Aging and Neutron Irradiation Embrittlement

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 or not 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 safety evaluation (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 control rod guide tube (CRGT) assembly lower flange welds, which are the primary components. Section 3.2.2 of the staff's safety evaluation 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 safety evaluation 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 safety evaluation 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 safety evaluation 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. In 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 or not 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.

In 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 safety evaluation 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 safety evaluation 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), Table 4-3 and 4-6. In addition, if defects are discovered during the examination, the applicant will enter the information into the Corrective Action Program 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 Corrective Action Program 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. In 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 has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.8 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 has 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 Section 4.2 of this SER, 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 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 in conformance 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 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 safety evaluation 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 has 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 safety evaluation 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.

Based on the program identified in LRA Section 3.1.2.2.6, the staff concludes that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.1.2.2.6 (Revision 1). The staff concludes that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.7 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 Water Chemistry Program.

The staff finds that for the stainless steel high pressure conduits (flux thimble guide tubes), the applicant has met 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 (Appendix A.1 of the SRP-LR) 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. In 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 has 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.

<u>Item 2</u>. 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.8 Cracking Due to Cyclic Loading

Table 3.1.1, items 3.1.1.25 and 3.1.1.26, are applicable to BWRs only, as discussed in SER Section 3.1.2.1.1 above.

3.1.2.2.9 Loss of Preload Due to Stress Relaxation

The staff reviewed LRA Section 3.1.2.2.9 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.

Based on the programs identified, the staff determines 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 has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a) (3).

3.1.2.2.10 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

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 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.

Based on the programs identified, the staff concludes that the applicant's program meets the further evaluation criteria of SRP-LR Section 3.1.2.2.12. For those AMR items that apply to LRA Section 3.1.2.2.12, the staff determined that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.13 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 Section 3.0.3.3.1, 3.0.3.1.1, and 3.0.3.2.1, respectively. These programs were found to be either consistent with the GALL Report or sufficient to manage aging of components within the scope of the AMP. In its review of components associated with item 3.1.1.31, the staff finds that the applicant has 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.14 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 towards 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 has 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 Changes in Dimensions Due to Void Swelling

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. The staff concludes that LRA Section 3.1.2.2.15 is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.16 Cracking Due to Stress Corrosion Cracking and Primary Water Stress Corrosion Cracking

Item 1. 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 does 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 is not occurring. 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 is not occurring. 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.

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 has met the further evaluation criteria, and the applicant's proposal to manage aging using the Water Chemistry Program and 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 evaluation of the applicant's Water Chemistry Program is documented in SER Section 3.0.3.2.1. The staff finds that the applicant has met the further evaluation criteria. Additionally, the applicant's proposal to manage aging using the Water Chemistry Program is acceptable to manage cracking due to PWSCC of the SG tube-to-tubesheet welds because 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 the Water Chemistry Program 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.

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. 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 and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.17 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 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 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 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.

Based on the programs identified, 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.2.2.18 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 RV penetrations—including nozzles and safe ends—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 has 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

<u>Nickel Alloy Closure Bolting exposed to borated water leakage</u>. 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 or Fiberglass Insulation Exposed to Plant Indoor Air. In LRA Table 3.1.2-2, the applicant stated that for calcium silicate or fiberglass insulation exposed to plant indoor air, there is no aging effect, and no AMP is proposed. The AMR items cite 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 and calcium silicate 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 and calcium silicate are expected to be inert to environmental effects. The staff further noted that both fiberglass and calcium silicate insulation have a potential for prolonged retention of any moisture to which they are 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 in-scope fiberglass or calcium silicate insulation 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 residual heat removal systems outside of containment are covered by jacketing with a few exceptions, such as areas 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 overlapping of joints, orienting horizontally-run jacketing 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 addressing the wetted insulation.

The staff's concern described in RAI 3.1.2.3.2-1 is resolved.

On the basis of its review, the staff finds that the applicant appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not addressed in the GALL Report. The staff finds that the applicant demonstrated that the effects of aging for these components will be adequately managed so that their intended functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.3.3 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 RV penetrations—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 3.1.2-3, 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 RV penetrations—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).

3.1.3 Conclusion

The staff concludes that the applicant has 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 engineered safety features (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 (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 (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 (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 (SER Section 3.2.2.2.3, 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
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 (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 (SER Section 3.2.2.2.3, item 4)
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 (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 (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 (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 (SER Section 3.2.2.2.4, 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
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 (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 (SER Section 3.2.2.2.6)
Steel drywell and suppression chamber spray system nozzle and flow orifice internal surfaces exposed to air-indoor uncontrolled (internal) (3.2.1.13)	Loss of material due to general corrosion and fouling	A plant-specific AMP is to be evaluated.	Yes	BWR only	Not applicable to PWRs (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 (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	Consistent with the GALL Report (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 (SER Section 3.2.2.2.8, item 3)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel (with or without 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 (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 (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 (SER Section 3.2.2.1.1)
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 (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 (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 (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 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	Consistent with the GALL Report (SER Section 3.2.2.1.1)
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

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 (3.2.1.29)	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
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

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-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 (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 (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 (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 (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 (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 (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 (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 (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 (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 (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 (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 (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
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
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 (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 (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 (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 (SER Section 3.2.2.1.3)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
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
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 (SER Section 3.2.2.1.1)
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 (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 (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 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 (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

The staff's review of the ESF component groups followed several approaches. One approach, documented in SER Section 3.2.2.1, discusses the staff's review of AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.2.2.2, 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 3.2.2.3, 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 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, 3.2.1.18 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 this determination, the staff finds 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 claim is acceptable.

LRA Table 3.2.1, item 3.2.1.22, addresses steel closure bolting exposed to air with steam or water leakage. The GALL Report recommends 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 closed-cycle cooling water 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 closed-cycle cooling 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 claim is acceptable.

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, that the applicable items in the GALL Report were not used, 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 claim is acceptable.

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 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 claim is acceptable.

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 claim is acceptable.

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 claim is acceptable.

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 claim is acceptable.

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 claim is acceptable.

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 closed-cycle cooling 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, piping components, piping elements, or heat exchanger components exposed to closed-cycle cooling 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 claim is acceptable.

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 closed-cycle cooling 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 piping, piping components, or piping elements exposed to closed-cycle cooling 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 claim is acceptable.

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 claim is acceptable.

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 claim is acceptable.

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 claim is acceptable.

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 claim is acceptable.

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 claim is acceptable.

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 claim is acceptable.

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 found it acceptable 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 finds that the applicant's claim is acceptable.

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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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. In 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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 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 22, 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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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.

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 is not occurring. 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 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 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.4 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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Item 2</u>. 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 residual heat removal heat exchangers and residual heat removal 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 item 3.2.1.12 and SRP-LR Section 3.2.2.2.6 to be 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

<u>Item 1</u>. 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.

<u>Item 2</u>. 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, therefore, finds the applicant's claim acceptable. 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 line 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 engineered safety features 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 integrated leak rate test 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

Fiberglass Insulation Exposed to Plant Indoor Air. 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 residual heat removal 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 addressing the wetted insulation.

The staff's concern described in RAI 3.1.2.3.2-1 is resolved.

Stainless Steel Heat Exchangers (RHR, RHR Pump Seal Water Cooler, RCP Thermal Barrier Cooler, and the CVCS Seal Water Return, BTRS Letdown Reheat, Excess Letdown, Letdown, and Regenerative Heat Exchangers) exposed to treated borated water (internal). 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, BTRS 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 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 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.

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).

3.2.2.3.4 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 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.

3.2.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the ESF system components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will 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 (SER Sections 3.3.2.2.1 and 4.7.1)
Steel and stainless steel piping, piping components, piping elements, and heat exchanger components exposed to air-indoor uncontrolled, treated borated water or treated water (3.3.1.2)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Fatigue is a TLAA (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	Consistent with the GALL Report (SER Section 3.3.2.2.2)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel 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 (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 (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 (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 (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 verifyingverify 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 (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 verifyingverify 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 (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 (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 (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 (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 (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 (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 (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 (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 (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 (SER Section 3.3.2.2.7, item 3)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel (with or without 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 (SER Section 3.2.2.2.8)
Steel piping, piping components, piping elements, and tanks exposed to fuel oil (3.3.1.20)	Loss of material due to general, pitting, crevice, and MIC and fouling	Fuel Oil Chemistry and One-Time Inspection	Yes	Fuel Oil Chemistry and One-Time Inspection programs	Consistent with the GALL Report (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 (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 (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 (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
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 (SER Section 3.3.2.1.1)
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 (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 (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 (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 (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 (SER Section 3.3.2.2.10, item 7)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel 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 (SER Sections 3.3.2.1.1 and 3.3.2.2.10, item 8)
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 (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 (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 (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 (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 (SER Section 3.3.2.2.14)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
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 (SER Section 3.3.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to treated water > 60 °C (140 °F) (3.3.1.37)	Cracking due to SCC and IGSCC	BWR Reactor Water Cleanup System	No	BWR only	Not applicable to PWRs (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 (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 (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 (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 (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 (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 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
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 (SER Section 3.3.2.1.1)
Steel closure bolting exposed to air-indoor uncontrolled (external) (3.3.1.45)	Loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	No	Bolting Integrity Program	Consistent with the GALL Report (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

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to closed-cycle cooling water (3.3.1.48)	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 (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
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

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel compressed air system piping, piping components, and piping elements exposed to condensation (internal) (3.3.1.53)	Loss of material due to general and pitting corrosion	Compressed Air Monitoring	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report (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 (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 (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 (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

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 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
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

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper-alloy piping, piping components, and piping elements exposed to raw water (3.3.1.70)	Loss of material due to pitting, crevice, and MIC and fouling	Fire Water System	No	Fire Water System Program	Consistent with the GALL Report
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
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 (SER Section 3.3.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, 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 (SER Section 3.3.2.1.2)
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 (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 (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

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper-alloy piping, piping components, and piping elements exposed to raw water (3.3.1.81)	Loss of material due to pitting, crevice, and 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 (SER Section 3.3.2.1.5)
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 (SER Report 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

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Structural steel (new fuel storage rack assembly) exposed to air-indoor uncontrolled (external) (3.3.1.86)	Loss of material due to general, pitting, and crevice corrosion	Structures Monitoring Program	No	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-absorbin g capacity due to boraflex degradation	Boraflex Monitoring	No	Not applicable to STP	Not applicable to STP (SER Section 3.3.2.1.1)
Aluminum and copper alloy > 15% Zn piping, piping components, and piping elements exposed to air with borated water leakage (3.3.1.88)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	No	Not applicable to STP	Consistent with the GALL Report (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 (SER Section 3.3.2.1.11)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and steel with stainless steel cladding piping, piping components, and piping elements exposed to treated borated water (3.3.1.91)	Loss of material due to pitting and crevice corrosion	Water Chemistry	No	Water Chemistry Program, and One-Time Inspection Program	Consistent with the GALL Report (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 (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
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

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 (3.3.1.96)	None	None	No	None	Consistent with the GALL Report (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

The staff's review of the auxiliary system component groups followed several approaches. One approach, documented in SER Section 3.3.2.1, discusses the staff's review of AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.3.2.2, 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 3.3.2.3, 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 claim is acceptable.

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 claim is acceptable.

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 claim is acceptable.

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 claim 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.

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 rw 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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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. 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 Standard 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 which 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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 closed-cycle cooling water, 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. As a result, the applicant has proposed a plant-specific program, Selective Leaching of Aluminum Bronze, 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 which are found to have indications of through-wall dealloying are evaluated and scheduled for replacement by the Corrective Action Program. 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. Pending the resolution of OI 3.0.3.3.3-1, 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 3.0.3.3.3-1.

The staff finds that for LRA item 3.3.1.84, it requires further information to complete its determination 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. The staff's issues are documented in OI 3.0.3.3.3-1.

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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 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.

Item 3. 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.

In 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 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 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.4 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Item 2</u>. 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 is not occurring. 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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. In its review of components associated with item 3.3.1.18, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.8 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 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.9 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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 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, 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.10 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 which 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.

In its review of components associated with item 3.3.1.25, 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 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 which 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Item 4</u>. 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 since control of lubricating oil contaminants may not always have been adequate to preclude corrosion, the effectiveness of lubricating oil contaminant control should be verified to ensure that corrosion is not occurring. 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.

In its review of components associated with item 3.3.1.26, 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, 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Item 5</u>. 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.

In its review of components associated with item 3.3.1.27, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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.

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 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program includes visual inspections for loss of material performed by qualified personnel. The staff also noted that the visual inspections include steel, stainless steel, aluminum, copper alloy, and other metallic and non-metallic components, and that they will be implemented during periodic maintenance, predictive maintenance, surveillance testing, and corrective maintenance activities. The staff further noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program 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.

In its review of components associated with item 3.3.1.28, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the

Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is acceptable for the following reasons:

- The applicant's program includes visual inspections which are capable of detecting loss of material due to pitting and crevice corrosion in copper alloy components.
- The applicant's program includes 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 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Item 7</u>. 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.

<u>Item 8</u>. 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. This information is provided 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, they are not applicable to STP. This information is provided in SER Section 3.3.2.1.1.

3.3.2.2.12 Loss of Material Due to Pitting, Crevice, and Microbiologically-Influenced Corrosion

<u>Item 1</u>. 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.

In its review of components associated with item 3.3.1.32, the staff finds that the applicant has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Item 2</u>. 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.

In 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 has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.13 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 walk downs. 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.14 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

<u>Closure Bolting Stainless Steel Exposed to Treated Borated Water</u>. 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.

<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).

3.3.2.3.2 Auxiliary Systems—Summary of Aging Management Evaluation—Spent Fuel Pool Cooling and Cleanup System—LRA Table 3.3.2-2

<u>Closure Bolting Stainless Steel exposed to Plant Indoor Air</u>. 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.

<u>Heat Exchanger (Spent Fuel Pool) Stainless Steel Exposed to Treated Borated Water (Internal)</u>. 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, closed-cycle cooling water, 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 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>Closure Bolting Copper Alloy exposed to Plant Indoor Air</u>. 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 has 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.

<u>Strainer Carbon Steel Clad with Copper-Nickel Exposed to Raw Water Internal</u>. 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 has 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 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 corrective action database. As such, the staff finds that the applicant has 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 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 has 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. Pending the resolution of OI 3.0.3.3.3-1, 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 3.0.3.3.3-1.

<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 has 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 which 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 has 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.

Heat Exchanger Components Managed for Reduction of Heat Transfer. 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.

The applicant further 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 since 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," since 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 is not occurring;occurring 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.

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 has 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 closed-cycle cooling water, 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) due to 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 closed-cycle cooling water 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.

<u>Copper Alloy Greater than 15 Percent Zinc Solenoid Valve Exposed to Plant Indoor Air</u>. The staff's evaluation for copper alloy (greater than 15 percent zinc) 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.

<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).

3.3.2.3.7 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.

<u>Copper Alloy (Greater than 15 percent Zinc) Solenoid Valve Exposed to Plant Indoor Air</u>. 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 that is 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 has 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 is not occurring.

<u>Gray Cast Iron Solenoid Valve Exposed to Potable Water</u>. 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. The GALL Report, Revision 2, states that gray cast iron (included with 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, comprising both visual and mechanical techniques, of a sample of components for each system, material, and environment combination—including gray cast iron valves—to confirm that selective leaching is not occurring.

<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).

3.3.2.3.8 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 is 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 has 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, closed-cycle cooling water, 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 160 °F. The applicant also stated that the maximum outlet temperature during normal operation in the ECW system is 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 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 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).

3.3.2.3.13 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 standby diesel generator 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.

<u>Elastomeric Caulking and Sealant Exposed to Atmosphere and Weather, and Carbon Steel Tank Exposed to Concrete</u>. 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 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 has 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 has 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.

<u>Copper Valves and Solenoid Valves Exposed to Atmosphere and Weather</u>. 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 has 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.

<u>Cast Iron Valves Exposed to Plant Indoor Air</u>. 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 has 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.

<u>Stainless Steel Tubing, Closure Bolting, Piping, and Valves Exposed to Atmosphere and Weather (External)</u>. 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.

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 has 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.

Elastomer Flexible Hoses Exposed to Fuel Oil Internal Environment. 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.

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).

3.3.2.3.19 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 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 and listed in LRA Table 3.3.2-19, the applicant has 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).

<u>Calcium Silicate or Fiberglass Insulation Exposed to Plant Indoor Air</u>. In LRA Table 3.3.2-19, the applicant stated that, for calcium silicate or fiberglass insulation exposed to plant indoor air, there is no aging effect, and no AMP is proposed. The AMR items cite 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 and calcium silicate insulation are 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 and without the potential for water leakage, spray, or condensation, fiberglass and calcium silicate are expected to be inert to environmental effects. The staff further noted that both fiberglass and calcium silicate insulation have potential for prolonged retention of any moisture to which they are 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 or calcium silicate insulation is covered by jacketing and explain what procedure requirements are in place so as 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, those being areas not likely to receive environmental damage and RCPB penetrations.

(b) Plant specifications require that most of the insulation be 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 being 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 and during RFOs, and 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.

Thermoplastic Tank Exposed to Plant Indoor Air. 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.

Thermoplastic Tank Exposed to Zinc Acetate. 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 does 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 140 °F, with intermittent design service of 160 °F; however, the normal operating temperature is 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 has 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.

<u>Copper Alloy (Greater than 15 Percent Zinc) Solenoid Valve Exposed to Plant Indoor Air</u>. The staff's evaluation for copper alloy (greater than 15 percent zinc) 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.

<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).

3.3.2.3.20 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 closed-cycle cooling water, 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.

<u>Heat Exchanger Titanium Exposed to Lubricating Oil</u>. 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, yet 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 has 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 has 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 has 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 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 required 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 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 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).

3.3.2.3.25 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, closed-cycle cooling water, 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 Section 3.3.2.3.17.

<u>Aluminum Piping and Valves Exposed to Atmosphere and Weather</u>. 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 has 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 has 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 has 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 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).

<u>Nickel-Alloy Piping, Valve Exposed to Sodium Hydroxide</u>. 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 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 has 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 to be used for the management of 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 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 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 has 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 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>PVC Piping Expose to Potable Water (Internal)</u>. 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) since potable water is at least as benign as condensate, no aging effects from PVC piping exposure to potable water are anticipated.

<u>Piping, Accumulator, Pump, Sight Gauge, Strainer, Tank and Valve Stainless Steel Exposed to Sodium Hydroxide</u>. 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 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 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 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. According to 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 is not occurring.

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).

3.3.2.3.28 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 ethylene-propylene-diene (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 which 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 has 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 (SER Sections 3.4.2.2.1 and 4.3)
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 (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 (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 (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 (SER Section 3.4.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel 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 (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 (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 (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 (SER Section 3.4.2.2.4, item 1)
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 (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 (SER Section 3.4.2.2.5, 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 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 (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 (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 (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 (SER Section 3.4.2.2.7, item 1)
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 (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 (SER Section 3.4.2.2.7, 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 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 (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 (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 (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 (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
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 (SER Section 3.4.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel 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 (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 (SER Section 3.4.2.3.7)
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 (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 (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 (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 (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 (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 (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
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 (SER Section 3.4.2.1.1)
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 (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 (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	Not applicable to STP	Consistent with the GALL Report (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 (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 (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
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
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

The staff's review of the steam and power conversion system component groups followed several approaches. One approach, documented in SER Section 3.4.2.1, discusses the staff's review of AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.4.2.2, 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 3.4.2.3, 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
- 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
- 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 claim is acceptable.

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 claim is acceptable.

LRA Table 3.4.1, item 3.4.1.23, is associated with managing stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water 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 closed-cycle cooling 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 claim is acceptable.

LRA Table 3.4.1, item 3.4.1.24, is associated with managing steel heat exchanger components exposed to closed-cycle cooling water 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 closed-cycle cooling 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 claim is acceptable.

LRA Table 3.4.1, item 3.4.1.26, is associated with managing copper-alloy piping, piping components, and piping elements exposed to closed-cycle cooling water 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 closed-cycle cooling 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 claim is acceptable.

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 closed-cycle cooling 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, stainless steel, or copper alloy components exposed to closed-cycle cooling 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 claim is acceptable.

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 claim is acceptable.

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 claim is acceptable.

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 claim is acceptable.

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 claim is acceptable.

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 closed-cycle cooling water, 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 claim is acceptable.

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 claim is acceptable.

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 claim is acceptable.

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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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

<u>Item 1</u>. LRA Section 3.4.2.2.2.1, associated with LRA Table 3.4.1, items 3.4.1.2, 3.4.1.3, 3.4.1.4, and 3.4.1.6, 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 is not occurring. 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 staff noted that a search of the applicant's LRA and UFSAR confirmed 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 those 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Item 2</u>. 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 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.

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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.3 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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Item 2</u>. 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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.5 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 claim 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 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 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.7 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 is not occurring. 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. In its review of components associated with items 3.4.1.6, 3.4.1.15, and 3.4.1.16, the staff finds that the applicant 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 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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. In its review of components associated with item 3.4.1.17, 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 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 verified to ensure that corrosion is not occurring. 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 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.

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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.8 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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.9 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, they are not applicable to STP. This information is provided in SER Section 3.4.2.1.1.

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 or fiberglass insulation exposed to plant indoor air</u>. In LRA Tables 3.4.2-1, 3.4.2-3, and 3.4.2-5, the applicant stated that for calcium silicate or fiberglass insulation exposed to plant indoor air, there is no aging effect, and no AMP is proposed. The AMR items cite 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 and calcium silicate 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 and calcium silicate are expected to be inert to environmental effects. The staff further noted that both fiberglass and calcium silicate insulation have potential for prolonged retention of any moisture to which they are 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 in-scope fiberglass or calcium silicate insulation is covered by jacketing, so as 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 being areas 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 addressing the wetted insulation.

The staff’s concern described in RAI 3.1.2.3.2-1 is resolved.

<u>Aluminum Valves Exposed to Lubricating Oil</u>. 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 has identified all credible aging effects for this component, material, and environment combination.

<u>Aluminum Solenoid Valves Exposed to Lubricating Oil</u>. 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 has identified all credible aging effects for this component, material, and environment combination.

<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).

3.4.2.3.2 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.

<u>Copper Alloy (Greater than 15 Percent Zinc) Solenoid Valve Exposed to Plant Indoor Air</u>. The staff's evaluation for copper alloy (greater than 15 percent zinc) 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 of calcium silicate and fiberglass insulation exposed to plant indoor air with no aging effects and no AMP required, citing generic note J, is documented in SER Section 3.4.2.3.1.

<u>Closure Bolting Stainless Steel Exposed to Plant Indoor Air</u>. 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 Corrective Action Program. 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, 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 has 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.

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 of calcium silicate and fiberglass insulation exposed to plant indoor air with no aging effects and no AMP required, citing generic note J, 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 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 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 AFW storage tank 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 AFW storage tank.

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 AFW storage tank 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 AFW storage tanks, 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 has 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 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. 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 had initially 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 has 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).

3.4.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the steam and power conversion system components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will 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 (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 (SER Section 3.5.2.2.1.2)
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 (SER Section 3.5.2.2.1.2)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
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 150 °F general and 200 °F local (SER Section 3.5.2.2.1.3)
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 (SER Section 3.5.2.2.1.4)
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 (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

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: 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 (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 (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 50, Appendix J programs	Fatigue of metal components is a TLAA (SER Section 3.5.2.2.1.8)
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

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: 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 (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 (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 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
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 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
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 (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: 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 (SER Section 3.5.2.2.2.1)
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 (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 (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 (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
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 (SER Section 3.5.2.2.2.1)
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 (SER Section 3.5.2.2.2.1)
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	Structures Monitoring Program	Not applicable; Lubrite® was not used on RPV support shoes or SG supports (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 (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 (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 150 °F general and 200 °F local (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 (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 (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 (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 (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 (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 (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 (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.	Structures Monitoring Program	Not applicable; no vibration isolation elements in-scope for license renewal (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 (SER Section 3.5.2.2.2.7)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
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
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 (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.

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: 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
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
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 (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

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: 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
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	ASME Section XI, Subsection IWF Program	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

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 support members, welds, bolted connections, and support anchorage to building structure (3.5.1.59)	None	None	No	None	Consistent with the GALL Report (SER Section 3.5.2.1.4)

The staff's review of the structures and component supports groups followed any one of several approaches. One approach, documented in SER Section 3.5.2.1, reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.5.2.2, reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.5.2.3, reviewed AMR results for components that the applicant indicated are not consistent with or not addressed in the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the structures and component supports component groups is documented in SER Section 3.0.3.

3.5.2.1 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
- Fire Protection
- Masonry Wall Program
- 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 STP 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 Appendix B, Section B2.1.12 of the LRA 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, 3.0.3.1.6, 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 emergency 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, 47, and 50, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 is 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 due to the fact that 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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 pre load 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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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.

<u>Item 1—Aging of Inaccessible Concrete Areas</u>. LRA Section 3.5.2.2.1.1, associated with LRA Table 3.5.1, item 3.5.1-1, addresses 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—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 has 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, item1. 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>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 (150 °F) and local areas (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 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 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.

In 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Item 5—Loss of Prestress Due to Relaxation, Shrinkage, Creep, and Elevated Temperature. LRA Section 3.5.2.2.1.5, associated with LRA Table 3.5.1, item 3.5.1.7, addresses 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 Section 4.5 of the LRA 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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 Chapter 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 has 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Item 7—Cracking Due to Stress-Corrosion Cracking</u>. 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 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 or not 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 120 °F, as specified in UFSAR Table 9.4-1, which is below the threshold temperature of 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 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 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 the 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; 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 has 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 has 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Item 10—Cracking Due to Expansion and Reaction with Aggregate, and Increase in Porosity and Permeability Due to Leaching of Calcium Hydroxide. LRA Section 3.5.2.2.1.10, 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, since 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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2.2 Safety-Related and Other Structures and Component Supports

The staff reviewed LRA Section 3.5.2.2.2 against the criteria in SRP-LR Section 3.5.2.2.2, which address several areas, as discussed below.

<u>Item 1—Aging of Structures Not Covered by the Structures Monitoring Program</u>. 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. In its review of components associated with item 3.5.1.23, the staff finds the applicant has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(3) 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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(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, item 8, 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 has met 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, item 8. 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(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 has met 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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(3) 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 has met 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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(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 has 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 has met 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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(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 3.5.1-15 and also 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 has met the further evaluation criteria because the requirements of ACI 201.2R are incorporated into ACI 211.1 by reference, which the applicant has 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Item 3—Reduction of Strength and Modulus of Concrete Structures Due to Elevated Temperature</u>. 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 150 °F for general areas and 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 150 °F for general areas or 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 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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(3) 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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Item 5—Cracking Due to Stress-Corrosion Cracking and Loss of Material Due to Pitting and Crevice Corrosion. LRA Table 3.5.1, item 3.5.1.38, 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 3.5.2.2.2.6.1, 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 has 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 1. For those items that apply to LRA Sections 3.5.2.2.2.6.1, the staff concludes that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(2) Reduction in Concrete Anchor Capacity Due to Degradation of the Surrounding Concrete, for Groups B1–B5 Supports

LRA Section 3.5.2.2.2.6.2, 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 has 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 3.5.2.2.2.6.2, the staff concludes that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(3) 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.

<u>Item 7—Cumulative Fatigue Damage Due to Cyclic Loading</u>. 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 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. 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 has 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 has 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 has 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).

3.5.2.3.2 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 3.5.2.3.1

<u>Coatings exposed to plant indoor air</u>. 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 D 5163, 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 has 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 D 5163. In addition, degraded coatings will be documented and summarized for further evaluation and trending, which is consistent with the GALL Report.

<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 which 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 has 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 has 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 has 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 (and stainless steel supports) 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 3.5.2.3.2.

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 3.5.2.3.1

Gypsum and Plaster Barriers Exposed to Plant Indoor Air. 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 has 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 has 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 has 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 and stainless steel supports 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 3.5.2.3.2.

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 3.5.2.3.1.

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 AFW storage tank foundation and shell.

3.5.2.3.11 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—Supports

<u>Components Managed for Loss of Material</u>. 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 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 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 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 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 has 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 has 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.

Conclusion. On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations for items in LRA Table 3.5.2-11 not addressed in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the structures and component supports within the scope of license renewal and subject to an AMR will be adequately managed 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 has identified the appropriate GALL Report AMPs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's AMR evaluation are documented in SER Section 3.6.2.1.

The staff also reviewed AMRs consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the SRP-LR Section 3.6.2.2 acceptance criteria. The staff's evaluations are documented in SER Section 3.6.2.2.

Table 3.6-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.6 and addressed in the GALL Report.

Table 3.6-1. Staff Evaluation for Electrical and Instrumentation and Controls in the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Electrical equipment subject to 10 CFR 50.49 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 (SER Section 3.6.2.2.1 and Section 4.4)
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 (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

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Conductor insulation for inaccessible medium-voltage 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
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 (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

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
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 (SER Section 3.6.2.2.2)
Transmission conductors and connections, Switchyard bus and connections (3.6.1.12)	Loss of material due to wind-induced abrasion and fatigue; loss of conductor strength due to corrosion; increased resistance of connection due to oxidation or loss of preload	A plant-specific AMP is to be evaluated.	Yes	None	Not applicable to STP (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

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) Insulation material (3.6.1.14)	None	None	No	No AERM or AMP	Consistent with the GALL Report

The staff's review of the electrical and I&C component groups followed any one of several approaches. One approach, documented in SER Section 3.6.2.1, reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.6.2.2, reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. 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 instrumentation and controls components and claimed that these AMRs are consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the report and for which the GALL Report does not recommend further evaluation, the staff's review determined whether the plant-specific components of these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant noted for each AMR 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 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 has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.1.1 AMR Results Identified as Not Applicable

Conductor Insulation for Electrical Cables and Connections Used in Instrumentation Circuits. 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.

Fuse Holders (Metallic Clamps). 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 has 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).

3.6.2.2 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 Section 4.4 of the LRA 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 has 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 walk downs 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 has not identified 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 has met the further evaluation criteria of SRP-LR Section 3.6.2.2.2.

<u>Conclusion</u>. Based on the programs identified above, the staff concludes that the applicant has 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 that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.2.3 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 pre-load 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 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 pre-load. 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 81 °F in July to 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 pre-load. 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 pre-load is not an AERM for the period of extended operation.

Staff Evaluation. 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 pre-load could occur in transmission conductors and connections and in switchyard bus and connections. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that this aging effect is adequately managed.

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 born 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 pre-load 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 due to the fact that 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 pre-load of transmission conductors and connections and switchyard bus and connections) are not applicable at STP; therefore, the applicant has 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 has met 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 has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the electrical and I&C components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended 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 and pending successful resolution of the indicated OIs, the staff concludes that the applicant has demonstrated that the aging effects will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the applicable UFSAR supplement program summaries and concludes that the UFSAR supplement adequately describes the AMPs credited for managing aging, as required by 10 CFR 54.21(d).

With regard to these matters and pending successful resolution of the indicated OIs, the staff concludes that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB and that any changes made to the CLB, in order to comply with 10 CFR 54.21(a)(3), are in accordance with the Atomic Energy Act of 1954 and NRC regulations.

SECTION 4

TIME-LIMITED AGING ANALYSES

4.1 Identification of Time-Limited Aging Analyses

This section of the safety evaluation report (SER) provides the staff's evaluation of the applicant's basis for identifying those plant-specific or generic analyses that need to be identified as time-limited aging analyses (TLAAs) for the applicant's license renewal application (LRA) and the list of TLAAs for the LRA. TLAAs are certain plant-specific safety analyses that involve time-limited assumptions defined by the current operating term. This section of the SER also provides the staff's evaluation of the applicant's basis for identifying those exemptions that need to be identified in the LRA.

Pursuant to the requirements in Section 54.21(c)(1) of Title 10 of the *Code of Federal Regulations* (10 CFR 54.21(c)(1)), an applicant for license renewal must list all evaluations, analyses, and calculations in the current licensing basis (CLB) that conform to the definition of a TLAA as specified in 10 CFR 54.3. A plant-specific or generic evaluation, analysis, or calculation is a TLAA in accordance with 10 CFR 54.3 if it meets all six of the following TLAA identification criteria:

(1) involves a system, structure, or component (SCC) within the scope of license renewal, as delineated in 10 CFR 54.4(a)

(2) considers the effects of aging

(3) involves time-limited assumptions that are defined by the current operating term (e.g., 40 years)

(4) was determined to be relevant by the applicant in making a safety determination

(5) involves conclusions or provides the basis for conclusions related to the capability of the SSC to perform its intended functions, as described in 10 CFR 54.4(b)

(6) is contained or incorporated by reference in the CLB

In addition, pursuant to 10 CFR 54.21(c)(2), applicants must list all plant-specific exemptions in the CLB that were granted in accordance with the exemption approval criteria in 10 CFR 50.12 and are based on a TLAA. For such exemptions, the applicant must evaluate and justify the continuation of the exemptions for the period of extended operation.

The U.S. Nuclear Regulatory Commission's (NRC's) guidance recommendations for reviewing LRA Chapter 4.1 sections are given in NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants (SRP-LR)," Section 4.1, "Identification of Time Limiting Aging Analyses." SRP-LR Section 4.1.1 summarizes the areas of review. SRP-LR Section 4.1.2 provides the staff's acceptance criteria for performing TLAA and LRA exemption identification reviews. SRP-LR Section 4.1.3 provides the staff's review procedures for performing the TLAA and LRA exemption identification reviews. SPR-LR Table 4.1-1 provides some case-by-case examples on whether a given analysis category would be required to be identified as a TLAA for an LRA. SPR-LR Table 4.1-2 provides a generic list of those analyses or calculations that are commonly identified as TLAAs for an LRA. SPR-LR

Table 4.1-3 provides a generic list of those analyses or calculations that may be identified as plant-specific TLAAs for an LRA.

4.1.1 Summary of Technical Information in the Application

4.1.1.1 Identification of Time-Limited Aging Analyses

LRA Section 4.1 states that the applicant reviewed and evaluated the evaluations, analyses, and calculations in the CLB for South Texas Project (STP), Units 1 and 2, against the six criteria for TLAAs in 10 CFR 54.3. The LRA also states that the applicant reviewed the list of TLAAs in the SRP-LR to determine if each TLAA is applicable to and included as part of the applicant's CLB. The applicant stated that it used the following guidance documents as of part of the basis for its TLAA identification methodology:

- NUREG-1800, "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants," Chapter 4
- NEI 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54—the License Renewal Rule"
- 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants"
- prior LRAs
- plant-specific document reviews and interviews with plant personnel

The applicant stated that its review of the CLB included a review of the following plant-specific or generic sources (documents or records):

- STP updated final safety analysis report (UFSAR)
- STP technical specifications (TS)
- NRC SERs (NUREGs) for the original operating licenses
- Subsequent NRC safety evaluations (SEs)
- STP and NRC docketed licensing correspondence
- Vendor, NRC-sponsored, and licensee topical reports
- STP design calculations
- Code stress reports or Code design reports
- STP plant drawings and specifications

The staff noted that LRA Table 4.1-1 identifies the following evaluations, analyses, or calculations in the CLB that meet the six criteria for TLAAs in 10 CFR 54.3:

- Reactor Pressure Vessel (RPV) Neutron Embrittlement Analyses in LRA Section 4.2:
    - LRA Section 4.2.1, Neutron Fluence Values
    - LRA Section 4.2.2, Pressurized Thermal Shock
    - LRA Section 4.2.3, Upper-Shelf Energy (USE)
    - LRA Section 4.2.4, Pressure-Temperature (P-T) Limits
    - LRA Section 4.2.5, Low Temperature Overpressure Protection
- Metal Fatigue Analyses in LRA Section 4.3:

- LRA Section 4.3.2, American Society of Mechanical Engineers (ASME) Code Section III Class 1 Fatigue Analyses of Vessels, Piping and Components:
    - Reactor pressure vessel, nozzles, head, and studs [LRA Section 4.3.2.1]
    - Control rod drive mechanism (CRDM) pressure housings and core exit thermocouple nozzle assemblies (CETNAs) [LRA Section 4.3.2.2]
    - Reactor coolant pump (RCP) pressure boundary components [LRA Section 4.3.2.3]
    - Pressurizer and pressurizer nozzles [LRA Section 4.3.2.4]
    - Steam generator ASME Code Section III Class 1, Class 2 secondary side, and feedwater nozzle fatigue analyses [LRA Section 4.3.2.5]
    - ASME Code Section III Class 1 valves [LRA Section 4.3.2.6]
    - ASME Code Section III Class 1 piping and piping nozzles [LRA Section 4.3.2.7]
    - Intermittent thermal cycling analysis performed in response to NRC Bulletin No. 88-08 [LRA Section 4.3.2.8]
    - Revised fatigue analysis for the pressurizer surge line performed in response to NRC Bulletin No. 88-11 [LRA Section 4.3.2.9]
    - High energy line break postulation based on fatigue cumulative usage factor [LRA Section 4.3.2.10]
    - Fatigue crack growth assessments and fracture mechanics stability analyses for leak-before-break (LBB) elimination of dynamic effects of primary loop piping failures [LRA Section 4.3.2.11]
    - ASME Code Section III Class 1 design of ASME Code Class 3 feedwater control valves [LRA Section 4.3.2.12]
- LRA Section 4.3.3, ASME Code Section III Subsection NG Fatigue Analysis for Reactor Pressure Vessel Internals
- LRA Section 4.3.4, Effects of Reactor Coolant System Environment on Fatigue Life of Piping and Components (Generic Safety Issue 190)
- LRA Section 4.3.5, Assumed Thermal Cycle Count for Allowable Secondary Stress Range Reduction Factor for American National Standards Institute (ANSI) B31.1 and ASME Code Section III Class 2 and 3 Piping
- LRA Section 4.3.6, Fatigue Analyses of Metal Bellows and Expansion Joints

- Environmental Qualification (EQ) of Electric Equipment in LRA Section 4.4
- Concrete Containment Tendon Prestress Analysis in LRA Section 4.5
- Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analyses in LRA Section 4.6:
    - LRA Section 4.6.1, Fatigue Waivers for the Personnel Airlocks and Emergency Airlocks
    - LRA Section 4.6.2, Fatigue Design of Containment Penetrations
- Plant-Specific TLAAs in LRA Section 4.7:

- LRA Section 4.7.1, Load Cycle Limits for Cranes, Lifts, and Fuel Handling Equipment Designed to CMAA-70
- LRA Section 4.7.3, TLAA for Corrosion Effects in the Essential Cooling Water (ECW) System
- LRA Section 4.7.5, Reactor Coolant Pump (RCP) Flywheel Fatigue Flaw Growth Analysis

The applicant provided its bases for dispositioning these TLAAs in accordance with the requirements in either 10 CFR 54.21(c)(1)(i), (ii), or (iii) in the applicable subsections of LRA Sections 4.2-4.7.

In addition, LRA Table 4.1-1 identifies the “Disposition Category” as “Not Applicable” for TLAAs related to “In-service Flaw Growth Analyses that Demonstrate Structural Stability for 40 years” (LRA Section 4.7.2) and “Absence of a TLAA for Reactor Vessel Underclad Cracking Analyses” (LRA Section 4.7.4).

The staff noted that LRA Table 4.1-2 states that the following analyses, which are listed in SRP-LR Tables 4.1-2 and 4.1-3 as potential or plant-specific TLAAs, do not meet the definition of a TLAA for STP:

- Inservice local metal containment corrosion analyses
- Intergranular separation in the heat-affected zone (HAZ) of reactor vessel (RV) low-alloy steel under austenitic stainless steel cladding
- Fatigue analysis for the main steam supply lines to turbine driven auxiliary feedwater pumps
- Flow-induced vibration endurance limit
- Ductility reduction of fracture toughness for reactor vessel internals (RVIs)
- Fatigue analysis for the containment liner plate
- RPV circumferential weld inspection relief (boiling-water reactor (BWR))

4.1.1.2 Identification of Regulatory Exemptions

Section 4.1.4 of the LRA states that the applicant’s review of the CLB identified seven exemptions, granted under the criteria of 10 CFR 50.12, that were currently in effect for the STP CLB. The LRA states that pursuant to 10 CFR 54.21(c)(2), of these exemptions, the exemption for implementation of the leak-before-break (LBB) analysis was the only exemption that was based in part on a TLAA. The applicant stated that its basis for extending the acceptance of the LBB analysis for the period of extended operation is given in LRA Section 4.3.2.11.

4.1.2 Staff Evaluation

4.1.2.1 Identification of TLAAs

The staff reviewed the applicant’s methodology for identifying the TLAAs and the TLAA results for the LRA against the six criteria for TLAA identification in 10 CFR 54.3 and the generic list of TLAAs in SRP-LR Section 4.1, including those in SRP-LR Tables 4.1-2 and 4.1-3, as applicable to the STP CLB. The staff used the acceptance criteria in SRP-LR Section 4.1.2 and the review procedures in SRP-LR Section 4.1.3 as the basis for its review.

4.1.2.1.1 Evaluations, Analyses, and Calculations in the CLB Conforming to 10 CFR 54.3 TLAA Criteria

The staff confirmed that the applicant included its TLAAs for the RPV neutron irradiation embrittlement analyses in the applicable referenced subsections of LRA Section 4.2, which includes the TLAAs for the neutron fluence, pressurized thermal shock (PTS), USE, P-T limits, and low temperature overpressure protection (LTOP). The staff noted that these analyses should be included as TLAAs for the LRA because the analyses are mandated by applicable NRC requirements (e.g., 10 CFR 50.61 for PTS, 10 CFR Part 50, Appendix G, for USE, P-T limit, and LTOP analyses; and 10 CFR Part 50, Appendix H, for RPV surveillance capsule neutron dosimetry and fracture toughness analyses). Additionally, the analyses conform to all six of the criteria for identifying TLAAs in 10 CFR 54.3. Thus, the staff noted that the applicant's identification of these TLAAs is consistent with the recommendations in SRP-LR Sections 4.1 and 4.2, which provide the bases for identifying these types of neutron irradiation embrittlement analyses as TLAAs in accordance with the requirements in 10 CFR 54.21(c)(1). Based on this review, the staff finds that the identification of these analyses as TLAAs is acceptable because it complies with 10 CFR 54.21(c)(1). The staff evaluated the applicant's basis for the disposition of each of these TLAAs in accordance with either 10 CFR 54.21(c)(1)(i), (ii), or (iii) in the applicable subsections of SER Section 4.2.

The staff confirmed that the applicant has included its TLAAs on metal fatigue analyses in the applicable subsections of LRA Section 4.3, as referenced in the "Summary of Technical Information" above. The staff noted that these analyses should be included as TLAAs for the LRA because the analyses are mandated by applicable design rules (e.g., those in Section III of the ASME Code or in the ANSI B31.1 design code) or applicable NRC requirements (e.g., 10 CFR Part 50, Appendix A, General Design Criterion (GDC) 4, for the LBB analyses), or were implemented as part of the applicant's commitments to applicable NRC generic communications (e.g., the supplemental fatigue analyses that were performed in response to the recommendations in NRC Bulletins 88-08 and 88-11). Additionally, the analyses conform to all six of the criteria for identifying TLAAs in 10 CFR 54.3. The staff noted that the applicant's identification of these TLAAs is consistent with SRP-LR Sections 4.1 and 4.3, which provide the bases for identifying these types of fatigue analyses as TLAAs in accordance with the requirements in 10 CFR 54.21(c)(1). Based on this review, the staff finds that the identification of these analyses as TLAAs is acceptable because it complies with 10 CFR 54.21(c)(1). The staff evaluated the applicant's basis for dispositioning each of these TLAAs in accordance with either 10 CFR 54.21(c)(1)(i), (ii), or (iii) in the applicable subsections of SER Section 4.3.

The staff confirmed that the applicant included its TLAA on environmental qualification (EQ) of electric equipment in LRA Section 4.4. The staff noted that the EQ analysis should be included as a TLAA for the LRA because the analysis is mandated by the requirements in 10 CFR 50.49 and conforms to all six of the criteria for identifying TLAAs in 10 CFR 54.3. The staff confirmed that the applicant's identification of the EQ TLAA is consistent with the staff recommendations in SRP-LR Sections 4.1 and 4.4, which provide the bases for identifying EQ analyses as TLAAs in accordance with 10 CFR 54.21(c)(1). Based on this review, the staff finds that the identification of the EQ TLAA is acceptable because it complies with 10 CFR 54.21(c)(1). The staff evaluated the applicant's basis for dispositioning the EQ TLAA in accordance with 10 CFR 54.21(c)(1)(iii) in SER Section 4.4.

The staff confirmed that the applicant included its TLAA on concrete containment tendon prestress analysis in LRA Section 4.5. The staff noted that the concrete containment prestress analysis should be included as a TLAA for the LRA because the analysis is mandated by applicable ASME Code Section III CC-3000 design rules, and the analysis conforms to all six of the criteria for identifying TLAAs in 10 CFR 54.3. The staff confirmed that the applicant's identification of the concrete containment tendon prestress TLAA is consistent with the staff recommendations in SRP-LR Sections 4.1 and 4.5, which provide the staff's bases for identifying concrete containment tendon pre-stress analyses as TLAAs in accordance with 10 CFR 54.21(c)(1). Based on this review, the staff finds that the identification of the concrete containment tendon prestress TLAA is acceptable because it complies with 10 CFR 54.21(c)(1). The staff evaluated the applicant's basis for dispositioning concrete containment tendon prestress analysis in accordance with 10 CFR 54.21(c)(1)(iii) in SER Section 4.5.

The staff confirmed that the applicant included its TLAAs on fatigue analyses for the containment structure and other structural components in LRA Section 4.6. The waiver analysis exempting the containment personnel and emergency airlocks from the performance of a cumulative usage factor (CUF) or I_t based fatigue analysis is in LRA Section 4.6.1. The CUF fatigue analyses for the containment penetrations are evaluated in LRA Section 4.6.2 and identified in LRA Table 4.6.2-1. The staff noted that these analyses should be included as TLAAs for the LRA because the analyses are mandated by the applicable fatigue calculation or fatigue waiver rules in Section III of the ASME Code and conform to the six criteria for TLAAs in 10 CFR 54.3. The staff noted that the applicant's identification of these TLAAs is consistent with staff recommendations in SRP-LR Sections 4.1 and 4.6, which provide the staff's bases for identifying containment structural analyses as TLAAs in accordance with 10 CFR 54.21(c)(1). Based on this review, the staff finds that the identification of these containment component TLAAs is acceptable because it complies with 10 CFR 54.21(c)(1). The staff evaluated the applicant's basis for dispositioning these TLAAs in accordance with either 10 CFR 54.21(c)(1)(i), (ii), or (iii) in SER Sections 4.6.1 and 4.6.2.

The staff confirmed that the applicant included the following plant-specific TLAAs for the LRA in the LRA Section 4.7:

- TLAA in LRA Section 4.7.1 on load cycle limits for the applicant's cranes, lifts, and fuel handling equipment
- TLAA in LRA Section 4.7.3 for the corrosion rate analysis for the essential cooling water (ECW) system, as performed in support of discontinuing the use of biocide inhibitors in this system
- TLAA in LRA Section 4.7.5 for the reactor coolant pump (RCP) flywheel flaw growth analysis

The staff noted that the applicant's identification of these TLAAs is consistent with the staff recommendations for identifying plant-specific TLAAs in SRP-LR Sections 4.1 and 4.7. Based on this review, the staff finds that the identification of these plant-specific TLAAs is acceptable because it complies with 10 CFR 54.21(c)(1). The staff evaluated the applicant's basis for dispositioning these plant-specific TLAAs in accordance with either 10 CFR 54.21(c)(1)(i), (ii), or (iii) in the applicable subsections of SER Section 4.7.

For the items identified as "Not Applicable" in LRA Table 4.1-1, specifically "In-service Flaw Growth Analyses that Demonstrate Structural Stability for 40 years" (LRA Section 4.7.2) and "Absence of a TLAA for Reactor Vessel Underclad Cracking Analyses" (LRA Section 4.7.4), the staff's evaluations of the information provided in the LRA are provided in SER Sections 4.7.2 and 4.7.4, respectively.

4.1.2.1.2 Evaluations, Analyses, and Calculations in the CLB That Do Not Conform to TLAA Criteria, or Absence of a TLAA due to Absence in the CLB

Absence of a TLAA for Inservice Local Metal Containment Corrosion Analyses. LRA Table 4.1-2 identifies that the applicant's review of the CLB did not identify any time-dependent local metal corrosion analyses for the containment structures. Therefore, the applicant stated that LRA does not need to include a localized metal corrosion TLAA for the containment structures because the generic "inservice local metal corrosion analysis" TLAA in SRP-LR Table 4.1-2 is not applicable to its CLB.

The staff reviewed the UFSAR for relevant information. The staff noted that the applicant addresses design features for managing corrosion of steel containment tendons in UFSAR Section 3.8.1 and the steel containment liners in UFSAR Section 3.8.5. The staff noted that UFSAR Section 3.8.1.7.3.1.2 indicates that the applicant does not use a time-dependent analysis to serve as the design basis for managing the impact of postulated corrosion effects on the steel containment tendons. The staff confirmed that the applicant uses its Concrete Containment Tendon Prestress Program (LRA Section B3.3) to manage the impact of postulated corrosion effects on the steel containment tendons. The staff also noted that this is the same AMP that is used to disposition the applicant's time-dependent prestress analysis for the tendons in accordance with the TLAA acceptance criterion in 10 CFR 54.21(c)(1)(iii).

In addition, the staff noted that UFSAR Section 3.8.5.1 indicates that the applicant does not use a time-dependent analysis as the design basis for managing the impact of postulated corrosion effects on the steel containment liners. Instead, the staff confirmed that UFSAR Section 3.8.5.1 indicates that the applicant uses a combination of cathodic protection and a waterproofing membrane as the basis for protecting the below-grade portions of the steel containment liner against the effects of corrosion. The staff confirmed that the applicant uses AMP B2.1.27, ASME Code Section XI, Subsection IWE, as its basis for managing the effects of aging (including potential loss of material due to corrosion) that are applicable to the metal containment liners. The staff's evaluation of the applicant's AMP B2.1.27 is provided in SER Section 3.0.3.1.9.

Based on this review, the staff confirmed that the applicant does not use any time-dependent corrosion analyses as the basis for protecting containment structure metal components against the effects of corrosion. The staff finds that the LRA does not need to identify any localized metal containment corrosion as TLAAs because the staff has confirmed that the applicant's CLB does not include these types of analyses. Additionally, the applicant uses either applicable design features or surveillance programs (i.e., the ASME Code Section XI, Subsection IWE, condition monitoring program) to manage the impacts of corrosion on the integrity of containment structure metal components.

Absence of a TLAA for Intergranular Separation in the HAZ of Reactor Vessel Low-Alloy Steel Under Austenitic Stainless Steel Cladding (RPV Underclad Cracks). In LRA Table 4.1-2 and LRA Section 4.7.4, the applicant stated that its review of the CLB did not identify any time-dependent flaw growth, flaw tolerance, or fracture mechanics evaluations to assess RPV underclad cracks. The applicant stated that, although there is an applicable Westinghouse topical report that assesses fatigue flaw growth analysis of postulated RPV underclad cracks, the report is not credited as part of its CLB for managing the potential for underclad cracks to develop in welds used to join the stainless steel cladding to RPV SA-508, Class 2, forging components (henceforth cladding-to-forging welds.) The applicant stated that its design basis uses the application of Regulatory Guide (RG) 1.43, "Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components" (May 1973), as the basis for precluding or mitigating the occurrence of underclad cracks in the RPV cladding-to-forging welds.

The staff reviewed the UFSAR for relevant information. The staff noted that UFSAR Section 5.2.3.3.2 states that all welding is conducted using procedures that are qualified in accordance with the applicable weld qualification rules of the ASME Code, Sections III and IX. Additionally, the UFSAR states that control of welding variables, as well as examination and testing methods, during procedure qualification and production welding is performed in accordance with the applicable ASME Code requirements. The staff also noted that UFSAR Section 5.2.3.3.2 states that Westinghouse (the nuclear steam supply system (NSSS) vendor for the RPV) met the intent of RG 1.43 by requiring qualification of any high-heat-input welding process (including the submerged-arc wide-strip and submerged-arc-6-wire welding processes) through implementation of a performance test, as recommended in Regulatory Position 2 of RG 1.43. The staff also noted, however, that UFSAR Section 5.3.1.2 states that the applicant would perform an additional "special evaluation" to verify and validate the special procedure qualification in its ability to assure freedom from RPV underclad cracking.

The staff also noted that LRA Section 4.7.4 did not make any reference to the "special evaluation" referenced in UFSAR Section 5.3.1.2 for underclad cracks. Specifically, the staff noted that the basis in LRA Section 4.7.4 did not identify how the applicant fulfilled the UFSAR Section 5.3.1.2 protocol for performing the special evaluation or describe what the "special evaluation" involved. The staff noted that the basis did not assess how the special evaluation, as implemented, compared to the six criteria for TLAAs in 10 CFR 54.3, and it did not justify whether the evaluation would need to be identified as a TLAA under the requirements of 10 CFR 54.21(c)(1).

By letter dated September 22, 2011, the staff issued request for additional information (RAI) 4.1-3 to address this issue. In this RAI, the staff asked the applicant to clarify how it fulfilled the UFSAR Section 5.3.1.2 protocol for performing a "special evaluation" to confirm and validate the special procedure qualification in its ability to assure freedom from RPV underclad cracking and to summarize what the special evaluation involved, with an appropriate CLB reference. The staff also asked the applicant to summarize how the "special evaluation," if implemented as part of the CLB, compares to the six criteria for TLAAs in 10 CFR 54.3 and to justify whether the evaluation would need to be identified as a TLAA under the requirements of 10 CFR 54.21(c)(1). The staff also asked the applicant to justify its basis for not performing the "special evaluation," if—contrary to the statement in UFSAR Section 5.3.1.2—the applicant had not performed the "special evaluation" as part of its CLB.

The applicant responded to RAI 4.1-3 by letter dated November 21, 2011, that the weld qualification process discussed in UFSAR Section 5.2.3.3.2 provides the "special evaluation" referred to in UFSAR Section 5.3.1.2. The applicant stated that the "special evaluation" is a performance test that was implemented consistent with the recommended Position 2 of RG 1.43. The applicant also stated that its review of the welding qualification test recommendations in Position 2 of RG 1.43 did not indicate that the tests would need to account for an aging mechanism or a time-dependent parameter that was defined in terms of the life of the plant. The applicant further stated that, based on this review, it concluded that the special evaluation referred to in UFSAR Section 5.3.1.2 did not meet the definition of a TLAA in 10 CFR 54.3.

The staff noted that, in its response to RAI 4.1-3, the applicant based its "absence of a TLAA" conclusion for the RV SA-508 Class 2 forging components on the criteria that were established in RG 1.43 and not on the applicant's own plant-specific basis that was implemented under the CLB to conform to the NRC's regulatory position in RG 1.43. Specifically, the staff noted the applicant did not indicate which plant-specific document in its CLB was implemented to conform to the RG 1.43 basis. The staff also noted that the applicant did not summarize which type of tests or evaluations were performed as part of its CLB to meet the recommended weld qualification criteria in RG 1.43 and, if an evaluation was performed as part of this qualification process, whether the evaluation would meet the six criteria for TLAAs in 10 CFR 54.3. Therefore, the staff did not have sufficient information to determine whether the applicant's CLB basis for conforming to RG 1.43 included an analysis that, when assessed against the six criteria for TLAAs in 10 CFR 54.3, would need to be identified as a TLAA in accordance with 10 CFR 54.21(c)(1).

As a result of an audit of the applicant's RV underclad cracking references, the staff also noted that the applicant referenced Westinghouse Non-Proprietary Class 3 Report WCAP-15338-A, "A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants," as an applicable RV underclad cracking reference. This report includes a generic fatigue flaw growth analysis for underclad cracks that would constitute a TLAA for a pressurized-water reactor (PWR) LRA if the report was being relied upon as part of the license renewal applicant's CLB. Thus, the staff also needed additional information on whether WCAP-15338-A was being relied upon as part of the CLB.

By letter dated February 15, 2012, the staff issued RAI 4.1-3a, requesting that the applicant reference the specific report, calculation, or analysis document that was used in the CLB to conform to the NRC's regulatory position in RG 1.43. The staff also asked the applicant to summarize the types of tests or evaluations that were performed as part of this CLB to be consistent with the NRC's regulatory position in RG 1.43. Additionally, if the CLB included any evaluations, analyses, or calculations in support of the RG 1.43 conformance basis, the staff asked the applicant to justify why the evaluations, analyses, or calculations would not need to be identified as TLAAs for the LRA.

The applicant responded to RAI 4.1-3a by letter dated March 29, 2012. In its response, the applicant stated that it was amending its CLB and design basis to adopt Westinghouse Report WCAP-15338-A as the basis for managing potential underclad cracking in the RV nozzles that are made from SA-508 Class 2 alloy steel forging materials. The applicant also stated that it was amending the LRA to identify the fatigue flaw growth analysis in WCAP-15338-A as a TLAA for the LRA. The applicant also stated that it was amending the following sections of the LRA in accordance with updated basis for managing RV undercladding cracking:

- LRA Section 3.1.2.2.5, which provides the applicant's aging management further evaluation response to SRP-LR Section 3.1.2.2.5
- LRA Tables 4.1-1 and 4.1-2, which amend the LRA to identify that the fatigue flaw growth analysis in WCAP-15338-A is a TLAA for evaluating the stability of potential RV underclad cracks in those RV nozzles that are fabricated from SA 508, Class 2 alloy steel forging materials
- LRA Section 4.7.4, which amends the LRA to provide the applicant's summary and discussion on why the analysis in WCAP-15338-A is acceptable for evaluating and managing potential RV underclad cracks in the associated RV nozzles and the

applicant's basis for dispositioning the fatigue flaw growth analysis in WCAP-15338-A in accordance with 10 CFR 54.21(c)(1)(i)

- Inclusion of LRA Section A.3.6.5, which provides the applicant' UFSAR supplement summary description for the fatigue flaw growth TLAA in WCAP-15338-A

The staff reviewed the applicant's response to RAI 4.1-3a and determined that the applicant's amended basis is consistent with the recommendations in SRP-LR Section 3.1.2.2.5, "Crack Growth Due to Cyclical Loading," which states the following:

> Crack growth due to cyclic loading could occur in reactor vessel shell forgings clad with stainless steel using a high-heat-input welding process. 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 the SA-508-Cl-2 forgings where the cladding was deposited with a high heat input welding process. The methodology for evaluating the underclad flaw should be consistent with the flaw evaluation procedure and criterion in the ASME Code Section XI Code, 2004 Edition 1. See the SRP-LR, Section 4.7, "Other Plant-Specific Time-Limited Aging Analysis," for generic guidance for meeting the requirements of 10 CFR 54.21(c).

The staff noted that the applicant amended LRA Section 3.1.2.2.5, LRA Tables 4.1-1 and 4.1-2, LRA Section 4.7.4, and the UFSAR supplement summary description for the RV underclad cracking TLAA in LRA Section A.3.6.5. However, the staff also noted that the LRA amendments associated with this revision should have amended LRA aging management review (AMR) item 3.1.1.21 to identify that the basis for managing cracking in the RV nozzles made from SA 508, Class 2 steel forging materials is entirely consistent with AMR, item 21, in SRP-LR Table 3.1-1. The staff noted that the applicant should have amended LRA Table 3.1.2-1 to include a new Table 2 AMR item for these RV nozzles that use the associated TLAA as the basis for managing fatigue-induced cracking in the nozzles. Resolution of this issue is documented in the staff's evaluation provided in Section 3.1.2.2.5 of this SER. All other aspects of RAIs 4.1-3 and 4.1-3a are resolved.

The staff's evaluation of the amended LRA Section 4.7.4 is documented in SER Section 4.7.4.

<u>Absence of Fatigue Analyses for Main Steam Supply Lines to the Turbine-Driven Auxiliary Feedwater Pumps</u>. In LRA Table 4.1-2, the applicant identified that its review of the CLB did not identify any time-dependent fatigue analyses for the main steam supply lines to the turbine-driven auxiliary feedwater (AFW) pumps. Therefore, the applicant stated that the LRA does not need to include a fatigue TLAA for these components because the generic "fatigue analysis for the main steam supply lines to the turbine-driven auxiliary feedwater pumps" in SRP-LR Table 4.1-3 is not applicable to its CLB.

The staff reviewed the UFSAR for relevant information. The staff confirmed that UFSAR Table 10.1-1 indicates that the applicant's units are each designed with three motor-driven AFW pumps and one turbine driven AFW pump. The staff also confirmed that UFSAR Table 3.2.A-1 indicates that the main steam supply line to the turbine-driven AFW pump was designed to either ASME Code, Section III, subarticle NC or ND, design requirements for ASME Code Class 2 or 3 components.

The staff noted that the ASME Code Section III design code of record (1974 edition inclusive of the winter 1975 addenda) did not require explicit CUF or I_t fatigue analyses of these main steam supply lines. The staff noted, however, that the ASME Code, Section III, subarticle NC or ND, requirements may have required the applicant to perform a maximum allowable stress range reduction analysis for the main steam supply line to the turbine-driven AFW pump. The staff also noted that LRA Section 4.3.5 identifies the maximum allowable stress range reduction analyses for the ASME Code Class 2 and 3 piping as TLAAs for the LRA. The staff further noted that GALL Report AMR VIII.B1-10 identifies that fatigue is to be managed using a TLAA for steel main steam piping that is exposed to steam or secondary water environments and that the applicant included the applicable AMR line items for its steel main steam piping components in LRA Table 3.4.2-1. Thus, the staff noted that the applicant would need to provide further clarification and justification on why the maximum allowable stress range reduction TLAA discussed in LRA Section 4.3.5 would not be applicable to the main steam supply line that supplies steam to the turbine-driven AFW pump during a turbine-driven AFW system actuation.

By letter dated September 22, 2011, the staff issued RAI 4.1-4 to address this issue. In this RAI, the staff asked the applicant to provide its basis on why the cumulative fatigue damage in the main steam supply lines to the turbine-driven AFW pumps would not need to be managed using the maximum allowable stress range reduction TLAA in LRA Section 4.3.5.

The applicant responded to RAI 4.1-4 by letter dated November 21, 2011. In its response, the applicant clarified that ASME Code Section III requirements would have required it to include the main steam supply lines to the turbine-driven AFW pumps in accordance with the maximum allowable stress range reduction analysis (implicit fatigue analysis) methodology that is defined as a TLAA and evaluated in LRA Section 4.3.5. Therefore, the applicant stated that the main steam supply lines to the turbine-driven AFW pumps are within the scope of the components that are included in the implicit fatigue TLAA in LRA Section 4.3.5. The applicant stated that, in order to create the link between the AMR for these main steam supply lines in LRA Section 3.4 and the TLAA in LRA Section 4.3.5, it amended LRA Table 3.4.2-1 to include an AMR item for the main steam supply lines to the turbine-driven AFW pumps, which indicates that the applicant credits the implicit fatigue TLAA in LRA Section 4.3.5 for management of cumulative fatigue damage of these components.

The staff reviewed the applicant's response to RAI 4.1-4 and confirmed that the applicant amended the LRA to include the following additional AMR item for the main steam piping components, including the supply lines to the turbine-driven AFW pumps. Based on this response, the staff finds that the applicant's amended basis is acceptable because:

- The applicant has identified that the main steam supply lines to the turbine-driven AFW pumps are within the scope of the components that are included in the implicit fatigue TLAA in LRA Section 4.3.5.
- The applicant has amended the LRA to include the appropriate TLAA-based AMR item for the main steam system piping components, including the steam line piping to the turbine-driven AFW pumps.
- The amended basis creates the link in the LRA between the components and the basis for managing cumulative fatigue damage in the components using the stated TLAA.
- This complies with the aging management requirement in 10 CFR 54.21(a)(3) and with the requirement for identifying the applicable metal fatigue TLAA in 10 CFR 54.21(c)(1).

The staff's concerns expressed in RAI 4.1-4 are resolved.

Absence of Flow-Induced Vibration Endurance Limit TLAAs for Reactor Vessel. In LRA Table 4.1-2 and LRA Section 4.3.3, the applicant stated that its review of the CLB did not identify any time-dependent flow-induced vibration endurance limit analyses for the RVI components. The applicant stated that the CLB does not describe any time-limited effects for a licensed operating period associated with flow-induced vibration; therefore, there are no analyses in the CLB that are associated with flow-induced vibrations of the RVI components that would meet the definition of a TLAA in accordance with 10 CFR 54.3. The applicant concluded that the LRA does not need to include these types of TLAAs because the generic “flow-induced vibration endurance limit for the reactor vessel internals” TLAA in SRP-LR Table 4.1-3 is not applicable to or part of the CLB.

The staff reviewed the UFSAR for relevant information. The staff verified that the applicant’s flow-induced vibration analysis basis for RVI components is accounted for in the following sections and tables of the UFSAR:

- Section 3.9.2.3, Dynamic Response Analysis of Reactor Internals Under Operational Flow Transients and Steady-State Conditions
- Section 3.9.2.4, Preoperational Flow-Induced Vibration Testing of Reactor Internals
- Section 3.9.2.6, Correlations of Reactor Internals Vibration Tests with the Analytical Results
- Section 1.6, Material Incorporated By Reference, and Table 1.6-2, Westinghouse Topical Reports Incorporated By Reference—with the following WCAP Reports invoked by reference as part of the flow-induced vibrational analysis basis:
  - Proprietary NRC-Approved WCAP-8303-P-A, Revision 0, “Prediction of the Flow-Induced Vibration of Reactor Internals by Scale Model Tests”
  - Proprietary NRC-Approved WCAP-8516-P-A, Revision 0, “UHI Plant Internals Vibration Measurement Program and Pre and Post Hot Functional Examinations”
  - Proprietary NRC-Approved WCAP-8766-P-A, Revision 0, “Verification of Neutron Pad and 17x17 Guide Tube Designs by Preoperational Tests on the Trojan 1 Power Plant”
  - Proprietary WCAP-9395-P, “4XL Scale Model Internal Flow Test Structural Response Test” (UFSAR Section 1.5 indicates that this WCAP includes an assessment of the vibrational levels in the internals)
  - WCAP-9646, “Verification of Upper Head Injection Reactor Vessel Internals by Preoperational Test of the Sequoyah Power Plant”
  - Proprietary WCAP-10865, “South Texas Plant (TGX) Reactor Internals Flow-Induced Vibration Assessment”

The staff verified that, collectively, these UFSAR sections indicate that the applicant uses consistency with the NRC’s position in RG 1.20, “Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing,” as the basis for protecting the integrity of the RVI components against those aging effects that may be induced by flow-induced vibrations (e.g., cracking induced by flow induced vibrations or loss of material/wear induced by the vibrations.) The staff noted that RG 1.20 provides an acceptable position that, if followed, can be used to demonstrate how an applicant for an operating license would comply with the technical information requirements for flow-induced vibrations in 10 CFR 50.34. It also permits applicants applying the RG basis to assess flow-induced vibrations of their RVI components using prototypical data and tests results from other U.S. PWRs whose RVI components were well analyzed for their responses to flow-induced vibrations.

The staff also noted that UFSAR Section 3.9.2.3 provides the applicant's basis for conforming to the prototypical analysis basis in RG 1.20. This UFSAR section states that the applicant applies the flow-induced vibration analysis for the Indian Point Unit 2 internals, with some additional prototypical data and test results from the Trojan and Sequoyah Unit 1 reactors, as the prototypical basis for analyzing the response of the STP RVI components to flow-induced vibrations. UFSAR Section 3.9.2.4 provides the list of the confirmatory preoperational testing examinations that the applicant will perform of its RVI components (in lieu of performing instrument-implemented vibrational testing of the RVI components) in order to validate the prototypical flow-induced vibration analysis basis for STP and to demonstrate conformance of the STP RVI components with the NRC's position in RG 1.20. UFSAR Section 3.9.2.6 provides the applicant's basis for correlating the data from flow-vibration behavioral test studies to the data obtained from the Sequoyah and Trojan instrument tests to demonstrate the conservatism in the behavioral test studies estimates.

The staff noted that LRA Section 4.3.3 states that the CLB did not include any flow-induced vibration analyses that would need to be identified as a TLAA for the LRA. It also states that any flow-induced vibration analyses in the CLB either did not involve an assessment of an applicable aging effect (i.e., did not conform to 10 CFR 54.3 Criterion 2) or were not based on time-dependent assumptions defined by the life of the plant (i.e., did not conform to 10 CFR 54.3 Criterion 3). The staff also noted that, although LRA Section 4.3.3 referenced the applicability of UFSAR Section 3.9.2.3, it did not mention that the applicant's flow-induced vibrational basis for the RVI components was based on consistency with the NRC position in RG 1.20 or that the flow-induced vibrational bases in UFSAR Sections 3.9.2.4 and 3.9.2.6 were also part of the applicant's RG 1.20 basis. The staff also noted that the applicant did not identify in LRA Section 4.3.3 that WCAP-8303-P-A, WCAP-8516-P-A, WCAP-8766-P-A, WCAP-9395-P, WCAP-9646, and WCAP-10865-P were being relied upon as part of the applicant's RG 1.20 conformance basis, and it did not provide an assessment on whether the analyses in these WCAP reports would need to be identified as TLAAs when compared to the six criteria for TLAAs of 10 CFR 54.3. The staff further noted that LRA Section 4.3.3 also did not mention that the applicant credits its plant-specific PWR Reactor Internals Program (i.e., LRA AMP B2.1.35) with the management of the aging effects that are applicable to the RVI components, including those from a flow-induced vibration mechanism (e.g., cracking or loss of material).

By letter dated September 22, 2011, the staff issued RAI 4.1-5, requesting details on how the applicant's consistency with RG 1.20 for flow-induced vibrations was accounted for in the current design basis. The staff also asked the applicant to explain whether any analyses that are part of this RG basis (when assessed against the six criteria for TLAAs in 10 CFR 54.3) would need to be identified as TLAAs for the LRA under the criterion in 10 CFR 54.21(c)(1). In RAI 4.1-5, Part 1, the staff asked the applicant to clarify which edition of RG 1.20 was being used as the current basis for assessing flow-induced vibrations of the RVI components and to provide a summary of how the information in UFSAR Sections 3.9.2.3, 3.9.2.4, and 3.9.2.5 is related to the information in other referenced UFSAR sections. In RAI 4.1-5, Part 2, the staff asked the applicant to identify which of the WCAPs in UFSAR Table 1.6-2 were currently being relied upon as part of the applicant's RG 1.20 basis. The staff also asked the applicant to provide a summary of all analyses, evaluations, or calculations that were included in WCAP reports as part of the RG 1.20 basis and to perform a comparison of these analyses, evaluations, or calculations (if any) to the six criteria for defining TLAAs in 10 CFR 54.3. In

RAI 4.1-5, Part 3, the staff asked the applicant to justify whether or not the analyses, evaluations, or calculations provided in response to RAI 4.1-5, Part 2, would need to be identified as TLAAs for the LRA in accordance with the TLAA identification requirements in 10 CFR 54.21(c)(1).

The applicant responded to RAI 4.1-5, Parts 1, 2, and 3, by letter dated November 21, 2011. In its response to RAI 4.1-5, Part 1, the applicant stated that it is committed to the NRC regulatory position in RG 1.20, Revision 2 (May 1976). The applicant further stated that, under this basis, its units are “Non-Prototype, Category 1” plants that rely on the tests and analyses for evaluating the impacts of flow-induced vibrations on the structural integrity of RVI components at the three “prototype” Westinghouse units in the U.S. (i.e., as performed for the Indian Point Unit 2, Trojan, and Sequoyah Unit 1 reactors). The applicant clarified that UFSAR Section 3.9.2.3 specifically describes the portions of the analyses and tests at the “prototype” reactors that are applicable to the CLB and RG 1.20 conformance basis. The applicant clarified that UFSAR Section 3.9.2.4 specifically describes its basis for conforming to the regulatory position in RG 1.20, Revision 2, by demonstrating that the design differences between the applicant’s reactor and the “prototype” reactors would not have any significant effect on the vibratory responses of the RVI components and by describing the pre-service inspections that would be performed during the initial startups of the applicant’s units. The applicant clarified that UFSAR Section 3.9.2.5 is not related to the RG 1.20 consistency.

The staff found that the applicant resolved the administrative requests, which were addressed by RAI 4.1-5, Part 1, because the applicant clarified which version of RG 1.20 is being relied upon as part of the flow-vibrational analysis in the CLB. In addition, the applicant clarified how the design basis in the UFSAR addresses the applicant’s flow-vibrational analysis basis for its RVI components. Therefore, the staff’s concerns in RAI 4.1-5, Part 1—with respect to how the UFSAR establishes the design basis for conforming to the regulatory position in RG 1.20—are resolved.

In its response to RAI 4.1-5, Parts 2 and 3, the applicant stated that the following Westinghouse WCAP report bases[1] are included in the CLB consistent with the RG 1.20 recommendations: (1) WCAP-7879; (2) WCAP-8303-P-A; (3) WCAP-8516-P-A; (4) WCAP-8766-P-A; (5) WCAP-9395-P-A; (6) WCAP-9946; and (7) WCAP-10865. The applicant stated that the bases in these WCAP reports do not include any TLAAs because the reports do not include any analyses that are based on time-dependent assumptions defined by the life of the plant (i.e., the bases in the reports do not conform to Criterion 3 for identifying TLAAs in 10 CFR 54.3(a)).

The staff reviewed the applicant’s response to RAI 4.1-5, Parts 2 and 3, to determine whether the response provided a valid basis for concluding that the referenced WCAP reports do not include any analysis that would need to be identified as TLAAs for the LRA. The staff noted the applicant identified WCAP-10865 as the report that established how the applicant is consistent with RG 1.20 and why the applicant does not need to perform vibratory functional testing of the RVI components. The staff noted that WCAP-10865 references many of the flow-induced vibration WCAPs that were issued in regard to the flow-vibrational studies performed at the prototypical Westinghouse units (i.e., at the Trojan, Indian Point, Unit 2, and Sequoyah, Unit 1, nuclear plants). The staff confirmed that WCAP-10865 does not include any analyses that would need to be identified as TLAAs for the LRA because it only serves as a basis on why the

[1] These reports contain proprietary information. Therefore, the staff will not discuss the details of these reports in this SER to protect Westinghouse’s privileged information in the WCAP reports in accordance with the privileged information withholding requirements in 10 CFR 2.390.

WCAPs for the prototypical Westinghouse units could be used as the RG 1.20 consistency basis for the applicant's units.

The staff also determined that the applicant's response to RAI 4.1-5 provided an acceptable basis for concluding that the assessments in WCAP-8303-NP-A, WCAP-8516-P-A, and WCAP-9395-P did not include any TLAAs because the staff verified that the reports only summarized flow vibration measurement test results and the acceptability of these results, and did not involve any high-cycle modeling analyses that would need to be compared to the six criteria for TLAAs in 10 CFR 54.3.

However, the staff noted that the applicant stated that the methodologies in the WCAP-7879, WCAP-8766-P-A, and WCAP-9946 reports did include high-cycle modeling analyses, which evaluated the impact of flow-induced vibrations on the measured strains for the components. The staff further noted that, contrary to the applicant's determination, the high-cycle modeling analyses in these reports included a time dependency because the analyses assessed the strains in the components based on an assumed number of flow-induced vibration cycles. The staff noted that the analyses in the reports address applicable aging effects because the reports assess whether the flow-induced vibrations could induce high-cycle fatigue-induced cracking or changes in dimensions (i.e., strain-induced plastic deformation) in the components and whether the intended functions of the sister-plant RVI components that are within the scope of the WCAP reports would be impacted. The staff also noted that the applicant's response to RAI 4.1-5 indicated that the analytical bases in these WCAP reports were relied upon in the CLB as part of the applicant's basis for conforming to the recommended NRC position in RG 1.20. The staff confirmed that the sister-plant components in the analyses directly correlate to those RVI components that the applicant had identified as being with the scope of the AMR items in LRA Table 3.1.2-1.

Thus, the staff concluded that the analyses in these reports would meet Criteria 1, 2, 4, 5, and 6 for defining TLAAs in 10 CFR 54.3 for the following reasons:

- The analyses involve sister plant RVI components that are being used as the RG 1.20 basis for analogous RVI components within the scope of the applicant's LRA.
- The analyses involve the effects of aging.
- The analyses are being relied upon as part a safety basis decision in the CLB for conforming to the NRC's regulatory position in RG 1.20.
- The analyses involve conclusion relative to the ability of the analogous RVI components to perform their intended safety functions.
- The WCAP reports are incorporated by reference in the UFSAR.

Hence, the staff concluded that the applicant's "absence of a TLAA" basis that cited Criterion 3—the conclusion that the assessments in the reports did not include time-dependencies—would only be acceptable if the applicant could establish that the time-dependent variable (i.e., high-cycle vibrations) in the report was not defined in terms of the life of the plant (e.g., a 40-year operating basis).

By letter dated February 15, 2012, the staff issued RAI 4.1-5a, requesting clarification on whether the analysis of vibratory cycles (the time-dependent parameter in the analyses) in the WCAP-7879, WCAP-8766-P-A, and WCAP-9946 reports was defined in terms of the life of the applicant's units (e.g., for a 40 year design life). The staff also requested further justification on why the analyses would not need to be identified as TLAAs for the LRA.

The applicant responded to RAI 4.1-5a by letter dated March 12, 2012. In its response, the applicant clarified that the high-cycle vibratory analyses in Westinghouse Report Nos. WCAP-7879, WCAP-8766-P-A, and WCAP-9946 are not considered to be dependent on a time-dependent parameter defined by the life of the plant because the stress ranges associated with vibratory fatigue cycles are well below the lower bound stress endurance limit in which a high-cycle fatigue-induced failure could be postulated. The applicant stated that the RVI components within the scope of these reports could tolerate an infinite number of low-stress vibratory cycles. The applicant stated that the high-cycle vibratory fatigue analyses in WCAP-7879, WCAP-8766-P-A, and WCAP-9946 do not include any time dependency; therefore, high-cycle fatigue analyses in these reports do not need to be identified as TLAAs for the LRA because they do not conform to TLAA identification Criterion 3 in 10 CFR 54.3a.

The staff noted that the applicant's basis for concluding that high-cycle fatigue analyses in these WCAP reports are not TLAAs is based on the concept that the RVI components would not initiate high-cycle fatigue cracks if the stresses in the components were lower than that associated with the endurance limits for the materials of fabrication for the components. The staff finds that the basis provided in the response to RAI 4.1-5a is a valid basis for drawing this conclusion because the stresses associated with the high-cycle vibratory fatigue analyses for the RVI components within the scope of these reports would permit the components to withstand an extremely high number of low stress, high vibratory cycles beyond the number of vibratory cycles associated with the end of the period of extended operation. Additionally, the analyses would not conform to the TLAA Criterion 3 in 10 CFR 54.3(a), in that the analyses are not time-dependent analyses that are defined by the life of the plant (e.g., 40 years). Based on this evaluation, the staff concludes that the applicant has provided an acceptable basis for concluding that there are not any time-dependent, high-cycle vibratory analyses for the RVI components that need to be identified as TLAAs for the LRA.

In addition, the staff noted that the applicant is crediting its PWR Reactor Internals Program (LRA AMP B2.1.35) as its condition monitoring program for managing cracking in the RVI components. Therefore, the staff has additional assurance that the applicant will have an acceptable AMP in place to manage cracking of RVI components during the period of extended operation. The staff's evaluation of the PWR Reactor Internals Program is provided in SER Section 3.0.3.3.2. Therefore, the staff's concerns described in RAIs 4.1-5, Parts 1, 2, and 3, and 4.1-5a are resolved.

<u>Absence of Ductility Reduction or Fracture Toughness Reduction TLAAs for Reactor Vessel Internal (RVI) Components</u>. In LRA Table 4.1-2, the applicant identified that its review of the CLB did not identify any time-dependent ductility reduction analyses or reduction of fracture toughness analyses for RVI components. Therefore, the applicant stated that LRA does not need to include these types of TLAAs because the generic "ductility reduction of fracture toughness" TLAA in SRP-LR Table 4.1-3 is not applicable to or part of the CLB.

The staff reviewed the UFSAR for relevant information and verified that the UFSAR does not include or make any references to reduction of ductility analyses or reduction of fracture toughness analyses for the RVI components. The staff also noted that the applicant credits its PWR Reactor Internals Program as the basis for managing the effects of aging during the period of extended operation and that the program manages loss of fracture toughness in the RVI components as a result of neutron irradiation embrittlement, void swelling, and thermal aging for RVI components made from cast austenitic stainless steel (CASS), precipitation hardened stainless steels, and X-750 material.

Based on its review, the staff finds that the applicant has provided an acceptable basis for concluding the LRA does not need to include a TLAA related to ductility reduction or reduction of fracture toughness because the staff has confirmed that the CLB does not currently include these types of analyses for the RVI components.

The staff's evaluation of the applicant's PWR Reactor Internals Program to manage reduction of fracture toughness in the RVI components is provided in SER Section 3.0.3.3.2.

<u>Absence of a Fatigue Analysis TLAA for the Containment Liner Plate</u>. LRA Section 4.6 states that the applicant's review of the CLB did not identify any fatigue analyses for the containment liner plate (or the containment equipment hatches). The staff's evaluation of the applicant's conclusions is provided in SER Section 4.6.

<u>Absence of TLAA on Reactor Vessel Circumferential Weld Inspection Relief (BWR)</u>. In LRA Table 4.1-2, the applicant identified that the TLAA associated with inspection relief of RPV circumferential welds does not apply to the applicant because the applicant is a PWR and the analysis only applies BWRs; thus, this item is not applicable to its CLB.

The staff noted that SRP-LR Section 4.2 identifies that circumferential weld and axial weld probability of failure analyses that are used in support 10 CFR 50.55a reliefs from applicable inservice inspection requirements (i.e., those that are mandated by 10 CFR 50.55a(g)(6) and applicable ASME Code Section XI Category B-A inspection requirements) are only applicable to BWRs. The staff also noted that NUREG-1350 and the applicant's UFSAR identify the applicant's units as four-loop Westinghouse design PWRs. Based on this review, the staff finds that the applicant has provided an acceptable basis for concluding that the LRA does not need to include any RPV circumferential weld or axial weld probability of failure TLAAs because these types of assessments are only applicable to BWRs, and the staff confirmed that applicant's units are PWRs.

<u>Relevance of UFSAR Appendix 9A to the LRA</u>. As part of its review, the staff noted that UFSAR Appendix 9A provides the applicant's "Assessment of the Potential Effects of Through-Wall Cracks in the ECWS Piping." The staff noted that UFSAR Appendix 9A states that through-wall cracks were identified in the applicant's essential cooling water (ECW) system piping (aluminum bronze components), which were initiated by pre-existing weld defects and propagated by a dealloying phenomenon. The staff noted that UFSAR Appendix 9A states that "STPEGS has 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 operability of the [ECW system]."

The staff also noted that UFSAR Appendix 9A states that potential effects of leakage in the ECW system piping were assessed for the following impacts at the plant:

- internal flooding in rooms containing these pipes and other rooms which receive drains from these sources
- electrical shorts or grounds caused by water spray from the crack
- reduction in ECW system flow through the heat exchangers served by the affected ECW system piping train

- water losses from the essential cooling pump (ECP) not accounted for in the existing analysis
- possible effects on the transient pressures when the pump is started or stopped

The staff also noted that UFSAR Appendix 9A then referenced the following flaw-related evaluations and analyses that were performed to support the applicant's basis that any potential leakage from the ECW system piping would be detected before a fast fracture of the piping would occur:

- HL&P Laboratory Report MT-3512A, "Evaluation of Cracked Elbow-to-Nozzle Weld from South Texas Project Unit 1 Essential Cooling Water System"
- HL&P Laboratory Report MT-3512B, "Evaluation of Cracked Aluminum Bronze Pipe-to-Pipe Weld from South Texas Project Unit 2 Essential Cooling Water System"
- Aptech Calculation No. AES-C-1630-2, "Calculation of Critical Bending Stress for Flawed Pipe Welds in the ECW System"

The staff noted that the MT-3512A, MT-35612B, and AES-C-1630-2 evaluations referenced in UFSAR Appendix 9A appeared to be using an LBB-type of logic (leakage detection basis) to assess the potential flaws in the aluminum bronze ECW system components, and the apparent cause basis for UFSAR Appendix 9A was predicated on the conclusion that the existing flaws in the aluminum bronze components would be propagated by an aluminum bronze dealloying flaw growth mechanism. The staff also noted that the applicant did not mention UFSAR Appendix 9A and the three associated evaluations, and it did not provide in the LRA an assessment on whether these evaluations would need to be identified as TLAAs for the LRA, in accordance with 10 CFR 54.21(c)(1), when assessed against the six criteria for defining TLAAs in 10 CFR 54.3.

During the staff's onsite audit of the applicant's LRA AMPs the week of June 20-24, 2011, the staff noted that the applicant's LBB-type approach to the assessment of potential flaws in aluminum bronze ECW system components appeared to be based on three additional assessments that were not referenced as being relevant in UFSAR Appendix 9A:

(1) a vendor-specific leakage/seepage and soil diffusion calculation

(2) an applicant-specific leakage/seepage and soil diffusion calculation that was used to confirm the conclusions in the vendor-specific calculation

(3) an applicant-specific engineering report that summarized the applicant's results in the above vendor-specific and applicant-specific calculations, which appears to have been the basis for the conclusions in UFSAR Appendix 9A

The staff also noted that these evaluations did not include any flaw tolerance evaluations, which support the applicant's claim that a leak in an ECW system aluminum bronze component would be detected prior to a catastrophic fast fracture in the system's aluminum bronze piping.

The staff finds that if the leakage detection basis in UFSAR Appendix 9A was to be relied upon for aging management, it would need to be supported by an appropriate time-dependent flaw tolerance evaluation to demonstrate that the critical flaw size for the applicable piping would not be less than the flaw size that would lead to a detectable leak at the soil or soil/gravel surface. Furthermore, if the critical crack size was greater than the flaw size that would lead to a detectable leak (i.e., the leak-detection size), the analysis would need to demonstrate that a flaw the size of the leak-detection size would not grow and reach the critical flaw size limit for the piping prior to the time that it would take the applicant to detect such a leak at the soil surface or soil/gravel surface. In addition, any evaluations used to support this type of analysis would be relevant, even if the applicant had repaired the relevant indications under applicable ASME Code Section XI repair criteria, because the evaluations would still be needed to support the applicant's basis that visual examinations of the piping would be capable of detecting leakage from aluminum bronze ECW system components prior to a postulated fast fracture (i.e., catastrophic failure) of the piping.

The staff noted that the basis in UFSAR Appendix 9A was predicated on the assumption that flaw growth was occurring from an aluminum bronze dealloying mechanism. However, upon its audit of the HL&P MT-3512A and MT-35612B lab reports, the staff noted that the lab reports also indicated the occurrence of some failure striations in the weld failure photographs that could indicate that the flaws in the aluminum bronze materials had also been, at times, propagating by a low-cycle to high-cycle fatigue growth mechanism.

By letter dated September 22, 2011, the staff issued RAI 4.1-6, requesting that the applicant provide additional clarifications on the UFSAR Appendix 9A basis and whether the LRA should have included any relevant UFSAR Appendix 9A-based flaw tolerance TLAAs for the ECW system in accordance with the identification requirement in 10 CFR 54.21(c)(1). Specifically, in RAI 4.1-6, Part 1, the staff asked the applicant to explain why the applicable vendor-specific and applicant-specific leakage seepage and soil diffusion analyses, and the applicable engineer report, for the ECW system aluminum bronze components had not been referenced as applicable reports to the UFSAR Appendix 9A basis in the reference section of that UFSAR appendix. In RAI 4.1-6, Part 2, the staff asked the applicant to clarify whether the vendor-specific and applicant-specific leakage seepage and soil diffusion analyses, used for the UFSAR Appendix 9A safety basis, were supported by any flaw tolerance analyses to demonstrate that the critical flaw size for the applicable piping would not be less than the flaw size that would lead to a detectable leak at the soil or soil/gravel surface The staff asked the applicant to clarify, if the limiting critical flaw size was greater than the flaw size that would lead to a detectable leak (i.e., the leak-detection size), whether a flaw the size of the leak-detection size would not grow and reach the critical flaw size for the piping prior to the time that it would be detected at the soil surface or soil/gravel surface. The staff also asked the applicant to clarify whether such a flaw tolerance analysis, if performed as part of the CLB, would need to be identified as a TLAA for the LRA in accordance with the criteria in 10 CFR 54.21(c)(1). In RAI 4.1-6, Part 3, the staff asked the applicant to perform a comparison of the evaluations in HL&P Report Nos. MT-3512A and MT-3512B and in Aptech Calculation No. AES-C-1630-2 to the six criteria for defining analyses as TLAAs in 10 CFR 54.3. The staff also asked the applicant to provide its basis on why any evaluations, analyses or calculations in these reports would not need to be identified as TLAAs under the requirements of 10 CFR 54.21(c)(1). In RAI 4.1-6, Part 4, the staff asked the applicant to justify why the basis in UFSAR Appendix 9A did not need to consider and evaluate the possibility of fatigue flaw growth in these aluminum bronze components.

The applicant responded to RAI 4.1-6, Parts 1-4, in a letter dated December 8, 2011. In its response to RAI 4.1-6, Part 1, the applicant stated that the applicable leakage analysis is Calculation No. CC-5089, which is referenced on page 9A-2 of UFSAR Appendix 9A, and that the vendor-specific analysis is included as an attachment in Calculation CC-5098. The staff noted that the UFSAR Appendix 9A basis relied on more than one vendor-specific or applicant-specific analysis. The staff noted that in Tables 1 and 2 of the applicant's letter, dated December 8, 2011, the applicant listed all of the ECW aluminum bronze cast components and piping components that had degraded by either a selective leaching (dealloying) or crack propagation mechanism as part of its response to another RAI that was issued on this UFSAR basis (RAI B2.1.37-1). The staff also noted that these tables had referenced the applicable engineering analyses, material test reports, and condition reports that were issued relevant to applicant's leakage detection basis for these components. Therefore, based on the collective responses to RAIs B2.1.37-1 and 4.1-6, Part 1, the staff found that the applicant provided a definitive basis on the types of reports, calculations, and analyses that were being relied upon as part of the applicant's UFSAR Appendix 9A leakage management basis for the ECW system. The staff's evaluation of the applicant's UFSAR Appendix 9A basis to manage loss of material and cracking in the ECW system is provided in SER Section 3.0.3.3.3. Therefore, the staff's concerns expressed in RAI 4.1-6, Part 1, are resolved.

In its response to RAI 4.1-6, Parts 2 and 3, the applicant stated that the leakage detection basis for UFSAR Appendix 9A was based on the leakage detection threshold that was established in applicant's Calculation CC-5098 and that the critical crack was established in Aptech Calculation AES-C-1630-2. The applicant also stated that the crack length needed to produce a leak rate of 10 gallons per minute (gpm) was less than the critical crack length established in Aptech Calculation No. AES-C-1964-7. The applicant further stated that the referenced calculations do not involve any predictions of wastage (loss of material) progression by a selective leaching mechanism or flaw growth by a crack propagation mechanism such as fatigue or stress corrosion cracking. The applicant clarified that laboratory examinations indicate that a pre-existing crack at the root of a weld will support dealloying at the crack tip and that the crack would propagate through the dealloyed material until non-dealloyed material was reached. The applicant stated that the process could repeat itself until the crack extends fully through the wall of the component. However, the applicant also stated that the rate at which a crack would propagate could not be determined for this type of process. The applicant stated that since the calculations do not involve time-dependent assumptions, the analyses in the calculations do not conform to the criterion in 10 CFR 54.3(a), Criterion 3, and do not need to be identified as TLAAs for the LRA.

The staff reviewed the calculations in these documents and determined that any flaw tolerance evaluations in the Aptech calculations used limit-load or linear-elastic fracture mechanics analyses for the crack stability analyses. The staff also noted that these analyses only assessed a conservatively-assumed through-wall flaw size against the critical crack size for the analyzed component. The staff further noted that the flaw tolerance analyses did not include any time-dependent flaw growth calculations (e.g., growth by fatigue or by SCC) for the assumed flaws. The staff noted that the leak detection analysis basis in Calculation CC-5098 would not meet the definition of a TLAA because the period analyzed did not fully cover a 40-year life basis. The staff concluded that the applicant has provided an acceptable basis for stating that the flaw tolerance analyses in these reports are not TLAAs, because the analyses do not involve time-dependent assumptions defined by the life of plant, and thus do not conform to Criterion 3 in 10 CFR 54.3(a). Therefore, the staff's concerns expressed in RAI 4.1-6, Parts 2 and 3—with respect to identifying whether Calculation CC-5098 and the flaw tolerance evaluations in the Aptech calculations need to be identified as TLAAs for the LRA—are resolved.

The staff also noted that some of the applicant's material test reports indicated that some aluminum bronze components in the ECW system had failed and leaked as a result of a stress corrosion cracking (SCC) propagation mechanism, sometimes with and sometimes without dealloying as a contributing cause for the failure of the components. Thus, the staff questioned whether the applicant's leakage detection basis for aluminum bronze components in Calculation

CC-5098 is adequate because the supporting flaw tolerance bases did not account for potential SCC-initiated growth of the analyzed flaws in the calculations. The staff did not have sufficient assurance that the leaks from the analyzed components would be detected at the soil surface prior to a complete guillotine-type failure of the components because the flaw tolerance basis did not account for SCC-initiated growth of the analyzed flaws in the calculations. Additionally, the applicant did not sufficiently demonstrate that leakage from a pre-existing through-wall flaw would be detected before a full failure of an aluminum bronze component in the ECW system. The staff's concerns and evaluations related to the potential of SCC-initiated crack growth are provided in SER Section 3.0.3.3.3. The staff's evaluation in SER Section 3.0.3.3.3 includes an assessment on whether additional inspections and time-dependent flaw tolerance evaluations will be needed for the cast aluminum bronze components and aluminum bronze piping components in the ECW system during the period of extended operation.

In its response to RAI 4.1-6, Part 4, the applicant stated that although fatigue is a phenomenon that could occur in any piping system, selective leaching (dealloying) was the main contributing factor for the aluminum bronze components in the ECW system. The applicant also stated that the laboratory material test report photographs on the failed aluminum bronze components did not exhibit any evidence that fatigue was a contributing cause for the components that had failed by a crack growth mechanism. The staff reviewed the photographs in the material test reports and determined that the components had failed either by a selective leaching (dealloying) pitting mechanism or by crack initiation and growth where SCC was the main contributing mechanism for crack growth (i.e., with or without synergistic contributions of dealloying on the crack growth mechanism or on the fracture toughness property of the aluminum bronze material in the component). The staff concludes that the applicant has provided an acceptable basis for concluding that fatigue was not a contributing mechanism for the failures in the aluminum bronze ECW components. Therefore, the staff's concerns expressed in RAI 4.1-6, Part 4, are resolved.

Based on its review, the staff concludes that the applicant does not need to identify a TLAA relative to the UFSAR Appendix 9A basis in the CLB because the analyses and calculations that are relied upon in the CLB are not based on any time-dependencies defined by the life of the plant, and therefore do not satisfy TLAA identification Criterion 3 in 10 CFR 54.3(a)

SER Section 3.0.3.3.3 provides the staff's evaluation on the applicant's plans for managing loss of material by dealloying or cracking in the aluminum bronze ECW components.

4.1.2.2 Identification of Exemptions in the LRA

As required by 10 CFR 54.21(c)(2), the applicant must identify and evaluate all exemptions granted under 10 CFR 50.12 that are based on a TLAA and justify their use during the period of extended operation. The LRA states that each active exemption was reviewed to determine whether it was based on a TLAA.

The staff also reviewed the applicant's CLB to see if the CLB included any exemptions that were granted under 10 CFR 50.12 and that were based on a TLAA. The staff's review included a review of the current operating license for the facility and the applicant's UFSAR. The staff's review also included an "exemption" keyword search of the NRC's main and legacy libraries in the NRC's Agencywide Document Access and Management System (ADAMS) Document Control Library.

LRA Section 4.1.4 states that the CLB includes seven exemptions that were granted under the provisions of 10 CFR 50.12. Of these exemptions, the LRA states that the exemption on the LBB analysis (which forms the applicant's basis for complying with "dynamic effect" analysis relaxation provisions in 10 CFR Part 50, Appendix A, General Design Criterion (GDC) 4) was the only exemption that was based in part on a TLAA. The applicant stated that the LBB analysis would be needed for the period of extended operation to justify continued removal of the dynamic effect analyses from the scope of the UFSAR and to justify removal of the pipe whip restraints for the scope of the reactor coolant loop design during the period of extended operation.

The applicant indicated that the LBB analysis is identified as a TLAA in LRA Section 4.3.2.11. The staff confirmed that LRA Section 4.3.2.11 identifies the LBB analysis as a TLAA and that the LRA Section gives the applicant's basis for accepting the LBB TLAA in accordance with the acceptance criterion in 10 CFR 54.21(c)(1)(iii). The staff also confirmed that the effect of fatigue flaw growth on the intended pressure boundary function of the main coolant loop, and its impact of compliance with GDC 4, will be adequately managed for the period of extended operation. The staff evaluated the LBB TLAA and the basis for accepting this TLAA in accordance with 10 CFR 54.21(c)(1)(iii) in SER Section 4.3.2.11.

The staff noted that the applicant did not identify any additional exemptions in the CLB that were granted under the provision of 10 CFR 50.12 and were based on a TLAA. The staff could not determine whether the remaining six exemptions mentioned in LRA Section 4.1.4 would need to be identified as exemptions in the LRA under 10 CFR 54.21(c)(2) because the applicant did not identify upon which regulations the exemptions were based. The staff also noted that, in LRA Section (AMP) B2.1.15, "Reactor Vessel Surveillance," the applicant stated that an exemption was granted in the original license from meeting the requirements of 10 CFR Part 50, Appendix H. However, the applicant did not provide any discussion in the LRA on why this exemption would not need to be identified in the LRA under the criteria of 10 CFR 54.21(c)(2).

Based on the results of its ADAMS Legacy Library search, the staff noted that on May 4, 1999 (NRC Microfiche Accession No. 9905110094, Microfiche Address A7956, pages 355-359), the staff granted an exemption that permitted the applicant to apply the alternative methods in ASME Code Case N-514 as the basis for establishing the LTOP system pressure lift and arming temperature set points for the power operated relief valves (PORVs) that are credited for relieving pressure when the LTOP system is actuated. Specifically, the staff noted that, based on the Code Case methodology, this exemption permits the applicant to set the LTOP system pressure lift set points for the PORVs to a pressure value that is equivalent to 110 percent of the limiting pressure established in the approved P-T limits curve for the system's arming temperature set point. The staff also noted that the exemption granting the use of Code Case N-514 also permits the applicant to set the arming temperature based on the Code Case's arming temperature set point methodology.

In addition, the staff noted that in LRA Section 4.2 the applicant identified P-T limit analyses for Units 1 and 2 as TLAAs in the LRA. The staff also noted that the LTOP system set points are currently within the scope of TS limiting condition of operation (LCO) 3.4.9.3 and surveillance requirement (SR) 4.4.9.3, and the P-T limits are currently within the scope of LCO 3.4.9.2 and SR 4.4.9.2.

By email dated December 3, 2010, the staff issued RAI 4.1-1 to the applicant, requesting further clarification on why the exemption allowing use of Code Case N-514 (i.e., the exemption on the LTOP methodology) had not been identified as an exemption that was based on a TLAA. The applicant responded to RAI 4.1-1 by letter dated December 9, 2010. In its response, the applicant identified that the exemption regarding use of Code Case N-514 should have been identified as an exemption for the LRA that conforms to the exemption identification requirement in 10 CFR 54.21(c)(2). The applicant also amended the LRA to add the exemption on Code Case N-514 as an exemption that was based on a TLAA. The applicant clarified that the exemption would be applied during the period of extended operation and that the basis for accepting both P-T limit and LTOP TLAAs during the period of extended operation is given in LRA Sections 4.2.4 and 4.2.5, respectively, and includes application of the exemption on use of the Code Case to the LTOP methodology. The staff finds that the applicant has resolved the concerns raised in RAI 4.1-1 because the applicant has amended the LRA to include the exemption for Code Case N-514 as an exemption that is based on a TLAA and because this conforms to the exemption criterion requirement in 10 CFR 54.21(c)(2). The staff's evaluation of the LTOP TLAA is provided in SER Section 4.2.5. The staff's evaluation includes the basis for applying the exemption on the use of Code Case N-514 to the LTOP methodology.

In addition, the staff noted that, by Letter No. NOC-AE-000518, dated July 13, 1999, and as supplemented by letters dated October 14 and 22, 1999, January 26 and August 31, 2000, and January 15, 18, and 23, March 19, and May 8 and 21, 2001, the applicant had requested several other exemptions under the criteria of 10 CFR 50.12. Some of these were based on risk-informed approaches, but the staff was not able to confirm which of these were in the LRA. Therefore, the staff could not: (a) identify how many exemptions had been granted to the applicant in the CLB under the criteria in 10 CFR 50.12; (b) determine the appropriate regulations that the specific exemptions were based on, and what the exemptions involved; nor (c) identify how many of the exemptions would need to be identified as TLAAs in the LRA.

By letter dated September 22, 2011, the staff issued RAI 4.1-7, requesting further clarifications on the exemptions that the applicant referenced in LRA Section 4.1.4. In RAI 4.1-7, Part 1, the staff asked the applicant to identify all exemptions that were granted under the criteria of 10 CFR 50.12, and, of these exemptions, to identify the regulation for which each exemption was requested, summarize what the exemption involved, and state whether it remained in effect for the CLB. In RAI 4.1-7, Part 2, the staff asked the applicant to justify why each of the exemptions discussed in the response to Part 1 of RAI 4.1-7 would not need to be identified as an exemption in the LRA, pursuant to the exemption identification criterion in 10 CFR 54.21(c)(2). The staff also asked the applicant to account for the exemption to the requirements of 10 CFR Part 50, Appendix H, that was referred to in LRA Section B2.1.15, and the risked-informed exemptions which were requested in the applicant's letter of July 13, 1991.

The applicant responded to RAI 4.1-7, Parts 1 and 2, in a letter dated November 21, 2011. In its response, the applicant included a table that identified all of the regulatory exemptions that were granted to the applicant under the requirements of 10 CFR 50.12 and summarized the bases for these exemptions in the CLB. The table also included the applicant's bases for comparing the exemptions to the NRC's exemption identification criteria in 10 CFR 54.21(c)(2) and for concluding whether the exemptions were based on a TLAA. The applicant also amended LRA Section 4.1.4 for consistency with its RAI response. The following paragraphs discuss the exemptions in more detail.

The applicant identified that the CLB includes an exemption from the requirements of 10 CFR 70.24 for criticality monitoring during spent fuel handling operations. The applicant stated the NRC's granting of the exemption permits the applicant to perform spent fuel handling operations without the use of any criticality monitoring equipment. The exemption was granted because the applicant had adequately demonstrated that the probability of a criticality accident would be sufficiently low during spent fuel handling operations by meeting seven operational criteria. The applicant also stated that these criteria did not involve any time dependent parameters. The staff confirmed that the NRC's granting of the fuel handling operation exemption was based only on the applicant's conformance with seven fuel handling operational criteria and that the exemption was not based on any analysis that conformed to a TLAA. Based on this review, the staff concludes that the exemption from 10 CFR 70.24 does not need to be identified as an exemption in the LRA because the granting of the exemption is not based on an analysis that is a TLAA. Therefore, concerns raised in RAI 4.1-7 with respect to this exemption are resolved.

The applicant stated that the exemption granted on 10 CFR Part 50, Appendix J, containment leak rate testing requirements was in relation to compliance with the leak rate testing requirements in paragraph III.D.2(b)(ii) of the appendix. This paragraph requires full pressure testing of the air locks following opening during periods when containment integrity is not required (i.e., during Operating Modes 5 or 6). The applicant stated that the exemption permits the applicant to use the 10 CFR Part 50, Appendix J, paragraph III.D.2(b)(iii) seal leakage test as an alternative to the full pressure test required by paragraph III.D.2(b)(ii) of the appendix. The applicant stated that the exemption is based on the NRC acceptance of the position that, if the tests required by paragraphs III.D.2.(b)(i) and III.D.2(b)(iii) are current and if maintenance is performed on the air lock such that it is properly sealed, then there is no reason to expect the air lock to leak excessively. The applicant stated that, as such, this exemption is not based on any analysis that would need to be identified as a TLAA for the LRA. The staff noted that the applicant's description of the Appendix J exemption confirms that the exemption was based solely on substituting one 10 CFR Part 50, Appendix J requirement for another, which may be done as long as the applicant continues to perform appropriate maintenance on the containment air locks. The staff noted that the applicant's discussion of the exemption demonstrates that the exemption is not based on any analysis that would need to be identified as a TLAA. Therefore, the staff concludes that the exemption on the Appendix J testing requirements does not need to be identified as an exemption for the LRA because the exemption is not based on any analysis that is a TLAA. Therefore, the staff concerns raised in RAI 4.1-7 with respect to this exemption are resolved.

The applicant stated that the CLB includes an exemption from the requirements of 10 CFR 50.71(e) with regard to the schedule for reporting UFSAR revisions to the NRC. The staff noted that this exemption involves relaxations in schedule only and is not based on an analysis that is a TLAA. Based on its review, the staff concludes that the exemption from 10 CFR 50.71(e) does not need to be identified as an exemption for the LRA because the granting of the exemption is not based on an analysis that is a TLAA for the LRA. Therefore, concerns raised in RAI 4.1-7 with respect to this exemption are resolved.

The applicant stated that the CLB includes an exemption from the requirements of 10 CFR Part 50, Appendix A, GDC 4, for analyzing dynamic effects associated with a postulated rupture of reactor coolant pressure boundary (RCPB) piping. The applicant stated that the granting of the exemption from GDC 4 is based on a TLAA because it is based on the applicant's LBB analysis, which is identified as a TLAA for the LRA. The staff's basis for accepting exemption on GDC 4 has been previously discussed and evaluated in this section. Therefore, the concerns raised in RAI 4.1-7 with respect to this exemption are resolved.

The applicant stated that the CLB includes an exemption from the requirements of 10 CFR Part 50, Appendix G, "Fracture Toughness Requirements," allowing use of ASME Code Case N-514 for the pressure lift and temperature actuation setpoints on the applicant's LTOP system. The applicant identified that this exemption is based on the applicant's P-T limits TLAA. Therefore, concerns raised in RAI 4.1-7 with respect to this exemption are resolved.

The applicant also identified that the CLB includes an exemption from the adequate cooling requirements in 10 CFR 50.46 and 10 CFR Part 50, Appendix K. The staff confirmed that the exemption permitted the applicant to use Optimized ZIRLO™ as the fabrication materials for fuel cladding on up to eight lead test assemblies containing fuel rods, guide thimble tubes, and instrumentation tubes instead of the already-approved ZIRLO™ material approved for the facility. The staff also confirmed that the granting of the exemption was not based on an analysis that conforms to the definition of a TLAA in 10 CFR 54.3. Based on this review, the staff concludes that the exemption from 10 CFR 5046 and 10 CFR Part 50, Appendix K, does not need to be identified in the LRA because the granting of the exemption is not based on an analysis that is a TLAA for the LRA. Therefore, concerns raised in RAI 4.1-7 with respect to this exemption are resolved.

The applicant also identified that the CLB includes a special exemption that was requested in accordance with the risk-informed regulation in 10 CFR 50.69 from meeting specific requirements in 10 CFR Parts 21, 50, and 100 and was granted in accordance with the exemption provisions in 10 CFR 50.12. The applicant stated that the "non risk significant" (NRS) and "low safety significance" (LSS) components within the scope of the special exemption no longer fall within the scope of the EQ of electrical component requirements in 10 CFR 50.49. However, the applicant also stated that the qualification of the safety-related components at the facility is still part of the CLB and remains within the scope of the applicant's EQ requirements and that the exemption is based in part on the EQ TLAA that is given in Section 4.4 of the LRA.

The staff noted that the special exemption requests from meeting the specific requirements in 10 CFR Parts 21, 50, and 100 were approved in the NRC safety evaluation dated August 3, 2001 (ADAMS Accession Nos. ML011990368 and ML012040470) and granted 10 CFR 50.12-based exemptions from the following requirements:

- 10 CFR Part 50, Appendix B, quality assurance requirements
- 10 CFR 50.55a requirements for inservice testing and inservice inspection
- 10 CFR 50.49 requirements for EQ of safety-related electrical equipment

The staff noted that, of these exemptions, the exemption from the EQ requirements of 10 CFR 50.49 was the only exemption that was based on a TLAA. The staff verified that the applicant included its EQ TLAA in LRA Section 4.4. The staff evaluated the applicant's basis for accepting the EQ TLAA in accordance with 10 CFR 54.21(c)(1)(iii) and the impact that this TLAA will have on the 10 CFR 50.49-based "special requirements" exemption in SER Section 4.4. Based on its review, the staff concluded that applicant has met the requirements of 10 CFR 54.21(c)(2) because the applicant's letter of November 21, 2011, appropriately amended the LRA to identify the 10 CFR 50.49 based "special requirements" exemption as an exemption that was granted under 10 CFR 50.12 and that was based on a TLAA. Therefore, concerns raised in RAI 4.1-7, with respect to 10 CFR 50.49 based "special requirements" exemption, are resolved.

The staff confirmed that the remaining "special requirements" exemptions had risk-informed bases which were reviewed and approved by the staff in accordance with the exemption request approval criteria in 10 CFR 50.12. The staff also confirmed that the non-10 CFR 50.49 "special requirements" exemptions were not based on any time-dependent analyses that would need to be identified as TLAAs in the LRA. Based on its review, the staff concludes that the applicant does not need to identify these remaining “special requirements” exemptions as exemptions for the LRA because they are not based on any analyses that would need to be identified as TLAAs in the LRA. Therefore, they do not fall within the scope of exemptions that would need to be identified in accordance with the requirements of 10 CFR 54.21(c)(2), and the staff’s concerns expressed in RAI 4.1-7, with respect to the non-10 CFR 50.49 based “special requirements” exemptions, are resolved. RAIs 4.1-1 and 4.1-7 are resolved with respect to compliance with 10 CFR 54.21(c)(2) exemption identification requirements.

In its letter dated November 21, 2011, the applicant clarified that the CLB does not include any exemptions for 10 CFR Part 50, Appendix H, RV Surveillance Program requirements. The applicant stated that the statement in LRA Section B2.1.15 regarding an exemption in the program was in reference to a footnote in the UFSAR on page 5.3-4. The applicant stated that the footnote clarifies that weld coupons for the program are not samples from specimens taken from the actual manufacturing of the vessel but, instead, represent weld metal that is identical to the wire heat and flux lot used to fabricate the RV intermediate-to-lower-shell girth weld. The staff noted that the footnote on UFSAR page 5.3-4 demonstrates compliance with the RV surveillance program requirements in 10 CFR Part 50, Appendix H, because it documents that the program includes RV weld test coupons that are representative of the RV beltline welds. Therefore, the staff has confirmed that the clarification on the UFSAR section does not constitute an exemption from 10 CFR Part 50, Appendix H, requirements. The staff’s concerns in RAIs 4.1-1 and 4.1-7 with respect to compliance with 10 CFR Part 50, Appendix H, requirements are resolved, in that the CLB does not include any exemption from those requirements.

Based on the information provided by the applicant, the amendment to LRA Section 4.1.4, and the scope of staff’s review, the staff concludes that, in accordance with 10 CFR 54.21(c)(2), the LRA includes the appropriate exemptions that were granted under 10 CFR 50.12 and that were based on a TLAA.

4.1.3 Conclusion

On the basis of its review, the staff concludes the applicant has provided an acceptable list of TLAAs, as required by 10 CFR 54.21(c)(1). The staff confirmed that, as required by 10 CFR 54.21(c)(2), the applicant has identified the appropriate exemptions that were granted under 10 CFR 50.12 and that are based on a TLAA.

4.2 Reactor Vessel Neutron Embrittlement Analysis

During plant service, neutron irradiation reduces the fracture toughness of ferritic steel in the beltline region of the RV. As fracture toughness decreases with cumulative fast neutron exposure, the material’s resistance to crack propagation decreases. The projected reduction in fracture toughness is a function of fluence and temperature. Areas of review to ensure that the RV materials have adequate fracture toughness to prevent brittle failure during normal and off-normal operating conditions are as follows:

- Neutron Fluence Values (Section 4.2.1)
- Pressurized Thermal Shock (Section 4.2.2)
- Upper-Shelf Energy (Section 4.2.3)
- Pressure-Temperature Limits (Section 4.2.4)
- Low Temperature Overpressure Protection (Section 4.2.5)

4.2.1 Neutron Fluence Values

4.2.1.1 Summary of Technical Information in the Application

LRA Section 4.2.1 describes the applicant's TLAA for neutron fluence. LRA Section 4.2.1 states that the fluence values for the end of license extended were projected based on the results of the Capsule V and U analyses for STP Units 1 and 2, respectively. The revised fluences were determined with transport calculations using the DORT discrete ordinates code and the BUGLE-96 cross section library, which is derived from ENDF/B-VI. The neutron transport and dosimetry evaluation methodologies follow the guidance and meet the requirements of the most recent issue of RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence." The fluence projections were developed with dosimeter data for which all measurement-to-calculation comparisons fall well within the 20 percent limit, which is specified as the acceptance criteria in RG 1.190.

LRA Table 4.2-1 provides 60-year peak projections for neutron fluence values for each unit.

The applicant dispositioned the neutron fluence TLAA in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed for the period of extended operation.

4.2.1.2 Staff Evaluation

The staff reviewed LRA Section 4.2.1 and the neutron fluence TLAA, to confirm pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed for the period of extended operation. The staff reviewed the applicant's TLAA and the corresponding disposition consistent with the review procedures in SRP-LR Section 4.2.3. The applicant stated that the neutron fluence calculations adhere to the NRC position detailed in RG 1.190, and it described the technique used to determine the STP, Units 1 and 2, neutron fluence values. To confirm this information, the staff reviewed the following reports, which provide additional details about the neutron fluence calculations and RV dosimetry analyses:

- WCAP-16093, "Analysis of Capsule V from the South Texas Project Nuclear Operating Company South Texas Unit 1 Reactor Vessel Radiation Surveillance Program," (ADAMS Accession No. ML072500123)
- WCAP-16149, "Analysis of Capsule U from the South Texas Project Nuclear Operating Company South Texas Unit 2 Reactor Vessel Radiation Surveillance Program," (ADAMS Accession No. ML072490211)

Chapter 6 of each report describes the neutron fluence calculations and states that they were performed using the nuclear data described above and that the uncertainties were within the RG 1.190 acceptance criterion of 20 percent. The reports provide additional information concerning the neutron transport calculations. The DORT calculations were used to perform a 3D flux synthesis, and the calculations employed a P_5 legendre polynomial expansion and S_{16} angular quadrature.

The staff finds the applicant's neutron fluence calculations acceptable because the applicant performed the neutron fluence calculations per RG 1.190, and the fluence projections fall within the 20 percent limits of the RG. Fluence is managed for the period of extended operation by the Reactor Vessel Surveillance Program, which is described in LRA Section B2.1.15. The validity of these parameters, and the analyses that depend upon them, will be managed to the end of the period of extended operation. The staff finds the applicant has demonstrated pursuant to 10 CFR 54.21(c)(1)(iii), that the neutron fluence will be adequately managed for the period of extended operation.

4.2.1.3 UFSAR Supplement

LRA Section A3.1.3 provides the UFSAR supplement summarizing the TLAA evaluation of LTOP. The staff reviewed LRA Section A3.1.3, consistent with the review procedures in SRP-LR Section 4.2.3.2, which state that the applicant should provide a summary description of the evaluation of the RV neutron embrittlement TLAA and provide information equivalent to SRP-LR Table 4.2-1. Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.2.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the neutron fluence TLAA, as required by 54.21(d).

4.2.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging caused by neutron fluence will be adequately managed for the period of extended operation.

4.2.2 Pressurized Thermal Shock

4.2.2.1 Summary of Technical Information in the Application

LRA Section 4.2.2 describes the PTS evaluation of the STP, Units 1 and 2, RV beltline and extended beltline materials for the period of extended operation against the screening criteria established in accordance with the PTS Rule, 10 CFR 50.61, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events."

For STP Unit 1, the applicant stated that the limiting PTS reference temperature (RT_{PTS}) material is intermediate shell R1606-3 with an RT_{PTS} value of 83.6 °F at 54 effective full power years (EFPY), based on the information provided in LRA Table 4.2-2. For STP Unit 2, the applicant stated that the limiting RT_{PTS} material is intermediate shell R2507-2 with an RT_{PTS} value of 63.7 °F at 54 EFPY, based on the information provided in LRA Table 4.2-3. The applicant concluded that each material in the STP, Units 1 and 2, RVs that has a surface neutron fluence value exceeding $1.0\text{x}10^{17}$ n/cm^2 (E > 1.0 MeV) at 54 EFPY has been demonstrated to have an RT_{PTS} value less than the applicable screening criterion; therefore, the RT_{PTS} value analyses have been satisfactorily projected for 60 years of operation.

The applicant dispositioned the PTS evaluation TLAA in accordance with 10 CFR54.21(c)(1)(ii), that the analyses have been projected to the end of the period of extended operation.

4.2.2.2 Staff Evaluation

The staff reviewed LRA Section 4.2.2 to confirm that the PTS analyses have been projected to the end of the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(ii). The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with the review procedures in SRP-LR Section 4.2.3.1.2.2, which state that the documented results of the revised PTS analysis based on the projected neutron fluence at the end of the period of extended operation are reviewed for compliance with 10 CFR 50.61 (the PTS Rule). The

SRP-LR also states that the staff should confirm that the applicant has provided sufficient information for PTS for the period of extended operation. Per the requirements of the PTS Rule, license holders shall have projected RT_{PTS} values for each RPV beltline material through the end of its operating license. The RT_{PTS} value for each beltline material is evaluated from:

$$RT_{PTS} = RT_{NDT(u)} + \Delta RT_{PTS} + M$$

$RT_{NDT(u)}$ is the unirradiated reference temperature (RT_{NDT}) (as defined in the ASME Code, Section III, paragraph NB-2331), ΔRT_{PTS} is the shift in RT_{NDT} caused by neutron irradiation, and M is the margin term to account for uncertainties in the calculation. The methodology used for determining ΔRT_{PTS} and the margin term M are described in the PTS Rule, including provisions for the use of surveillance data. The PTS Rule also provides the NRC-approved screening criteria for plates, forgings, axial weld materials (270 °F), and circumferential weld materials (300 °F).

In LRA Tables 4.2-2 and 4.2-3, the applicant presented the projected RT_{PTS} values at 54 EFPY for STP, Units 1 and 2, respectively. These tables also present the input parameters necessary for calculating the applicant's RT_{PTS} values. The staff identified discrepancies and insufficient information for the input parameters. Therefore, by letter dated January 13, 2012, the staff issued RAI 4.2.2-1 requesting that the applicant provide complete material descriptions and describe the procedures used to determine the chemistry data, initial RT_{NDT}, and margins for the extended beltline materials to demonstrate that it has applied consistent approaches for both the beltline and the extended beltline materials. (Note that RAI 4.2.2-1 also requested information related to Charpy USE, as discussed in SER Section 4.2.3)

By letter dated April 17, 2012, the applicant submitted the requested information for the beltline and extended beltline materials that are expected to receive neutron fluence values greater than 1.0×10^{17} n/cm^2 (E > 1.0 MeV). The applicant revised Tables 4.2-2 and 4.2-3 to include projected RT_{PTS} values at 54 EFPY for beltline and extended beltline materials for Units 1 and 2, respectively. A revision to LRA Section 4.2.2 states that the fluence projections for the nozzle (upper) shell to intermediate shell circular weld and lower shell to lower head torus circular weld bound the extended beltline materials both above and below the beltline.

The staff notes that neutron fluence decreases as distance from the core increases. The applicant, in its analyses of neutron fluence for beltline components, assigned the neutron fluence value for the circular weld between the nozzle (upper) shell and intermediate shell to the RV beltline components above this location, and the neutron fluence for the circular weld between the lower shell and lower head torus to RV beltline components below this location. Since actual neutron fluence values would decrease above or below those points, respectively (due to the increasing distance from the core), the staff finds this approach for these extended beltline materials to be conservative and to provide acceptable projections of neutron fluence values for the period of extended operation.

The staff compared the unirradiated materials' properties in Tables 4.2-2 and 4.2-3 to the information in the current UFSAR. The staff noted that the initial RT_{NDT} values for the Unit 1 bottom head torus (R1617-1) and bottom head dome (R-1618-1) were both -50 °F in the UFSAR; however, each has a value of -30 °F in the LRA. Since the LRA value is more conservative, the staff finds these changes to be acceptable. The staff also noted that Tables 4.2-2 and 4.2-3 contain several extended beltline materials not listed in UFSAR Tables 5.3-3 and 5.3-4. For Units 1 and 2, these are: inlet/outlet nozzle to shell welds; nozzle (upper) shell longitudinal welds; nozzle (upper) shell to intermediate shell circumferential weld; lower shell to lower head torus circumferential weld; lower head torus longitudinal weld; and lower head torus to dome circumferential weld. The RAI response states that values of copper and nickel contents for these extended beltline materials were obtained from weld certification records and the STP RV specification. Where nickel values were not listed in the UFSAR or weld certification records, the RAI response states that a nickel value of 1.0 percent was assumed based on 10 CFR 50.61(c)(1)(iv)(A), which states the following:

> CF (°F) is the chemistry factor, which is a function of copper and nickel content. CF is given in Table 1 for welds and in Table 2 for base metal (plates and forgings). Linear interpolation is permitted. In Tables 1 and 2, "Wt-% copper" and "Wt-% nickel" are the best-estimate values for the material, which will normally be the mean of the measured values for a plate or forging. For a weld, the best estimate values will normally be the mean of the measured values for a weld deposit made using the same weld wire heat number as the critical vessel weld. If these values are not available, the upper limiting values given in the material specifications to which the vessel material was fabricated may be used. If not available, conservative estimates (mean plus one standard deviation) based on generic data may be used if justification is provided. If none of these alternatives are available, 0.35% copper and 1.0% nickel must be assumed.

Therefore, the staff finds that the assumption of 1.0 percent for these nickel values is acceptable.

The applicant stated that, according to the Weld Inspection Forms, the Unit 1 inlet nozzle to shell circumferential weld was fabricated using manual E-8018 type welds, and the initial RT_{NDT} values for the E-8018 type welds are bounded by the generic Linde 0091 flux type weld properties. Based on a review of measured initial RT_{NDT} values for E-8018 welds at other pants, the staff determined the generic bounding initial RT_{NDT} value of -56 °F for Linde 0091 from 10 CFR 50.61(c)(1)(ii) provides an appropriate estimate of the initial RT_{NDT} of the E-8018 welds in the Unit 1 RV. The staff's concerns in RAI 4.2.2-1 related to PTS are resolved.

As part of its review to confirm acceptability of the applicant's analysis, the staff performed confirmatory calculations of RT_{PTS} for each of the extended beltline materials in Tables 4.2-2 and 4.2-3 and concluded that the applicant's projected RT_{PTS} values are consistent with those calculated by the staff. With the addition of the extended beltline materials, the limiting material for Unit 1 was determined to be inlet nozzle R1613-4 with an RT_{PTS} of 127.3 °F, and the limiting material for Unit 2 was determined to be outlet nozzle R2012-1 with an RT_{PTS} of 111.1 °F. These values are below the screening criterion of 270 °F for plates, forgings, and axial weld materials.

Although the staff's confirmatory calculations yielded RT_{PTS} values consistent with those provided in LRA Tables 4.2-2 and 4.2-3, LRA Section 4.2.2 identifies the limiting material for each unit as an intermediate shell material—which has an RT_{PTS} value less than (i.e., less limiting than) that for the nozzle materials identified in the SER paragraph above—as the limiting material for the respective unit. To address the inconsistency between the text and the tables in LRA Section 4.2.2, the applicant, in a letter dated December 11, 2012, revised LRA Section 4.2.2. The revised section states that, while the limiting RT_{PTS} value for the beltline material for each unit is an intermediate shell material (as discussed above), the component with the most limiting RT_{PTS} value for the unit is the nozzle shell material as listed in the respective LRA Tables 4.2-2 and 4.2-3. For Unit 1, the limiting material is Inlet Nozzle R1613-4. For Unit 2, the most limiting material is Outlet Nozzle R2012-1. The staff finds the LRA section revision acceptable and consistent with its own confirmatory calculations.

Based on the above discussion, the staff concludes that the Units 1 and 2 RV beltline and extended beltline materials will satisfy the PTS requirements of 10 CFR 50.61 through the period of extended operation. The applicant's TLAA is acceptable because it meets the requirements of 10 CFR 54.21(c)(1)(ii) and will ensure that the Units 1 and 2 RV materials will have adequate RT_{PTS} values and fracture toughness through the period of extended operation.

4.2.2.3 UFSAR Supplement

LRA Section A3.1.2 provides the UFSAR supplement summarizing the PTS TLAA. The staff reviewed LRA Section A3.1.2, consistent with the review procedures in SRP-LR Section 4.2.3.2, which state that the applicant should provide a summary description of the evaluation of the RV neutron embrittlement TLAA and provide information equivalent to SRP-LR Table 4.2-1. Based on its review of the UFSAR supplement, the staff determines that the applicant provided an adequate summary description of its actions to address PTS, as required by 10 CFR 54.21(d).

4.2.2.4 Conclusion

On the basis of its review of the LRA and the applicant's response to RAI 4.2.2-1 (related to PTS), the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the PTS analyses have been projected to the end of the period of extended operation and will continue to meet the requirements of the PTS Rule (10 CFR 50.61). The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d), and therefore, is acceptable.

4.2.3 Upper-Shelf Energy

4.2.3.1 Summary of Technical Information in the Application

LRA Section 4.2.3 describes the applicant's TLAA for the evaluation of Charpy USE values for the 60-year period of extended operation. The applicant projected the Charpy USE using the 54 EFPY fluences described in Section 4.2.1 of the LRA, as attenuated to the 1/4T location in the RV wall thickness.

Charpy USE values for all of the beltline materials of the STP, Units 1 and 2, RVs were determined in accordance with RG 1.99, Revision 2, without the use of surveillance data (Position 1.2 of the RG), although the surveillance data were available and found to be credible. This approach results in lower (more conservative) projections for the USE at the end of the 60-year period of extended operation than the alternative (Position 2.2 of the RG). The projected USE values for the beltline and extended beltline materials remain above the 50 foot-pound (ft-lb) requirement through the period of extended operation, as indicated in LRA Tables 4.2-4 and 4.2-5 for STP, Units 1 and 2, respectively.

The applicant dispositioned the USE TLAA in accordance with 10 CFR 54.21(c)(1)(ii), that the analyses have been projected to the end of the period of extended operation.

4.2.3.2 Staff Evaluation

The staff reviewed LRA Section 4.2.2 and the USE TLAA to confirm, pursuant to 10 CFR 54.21(c)(1)(ii), that the Charpy USE analyses have been projected to the end of the period of extended operation.

The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with the review procedures in SRP-LR Section 4.2.3.1.1.2, which state that the documented results of the revised USE analysis based on the projected neutron fluence at the end of the period of extended operation are reviewed for compliance with 10 CFR Part 50, Appendix G. Appendix G to 10 CFR Part 50 contains the screening criteria that establish limits on the USE values for RV materials after neutron irradiation exposure. The regulation requires the value of USE be greater than 50 ft-lbs in the irradiated condition throughout the licensed life of the plant. USE values of less than 50 ft-lbs may be acceptable to the staff if it can be demonstrated that these lower values will provide margins of safety against brittle fracture equivalent to those required by ASME Code, Section XI, Appendix G.

RG 1.99, Revision 2, states that the predicted decrease in USE values due to neutron embrittlement during plant operation is dependent upon the amount of copper in the material and the predicted neutron fluence for the material. RG 1.99 outlines two ways to project the USE values for ferritic steels—Position 1.2 uses Figure 2 of RG 1.99, and Position 2.2 uses reactor surveillance data. As indicated above in Section 4.2.3.1 of this SER, the applicant stated that it used Position 1.2 to determine the Charpy USE values at the end of the period of extended operation for the RPV beltline materials, because Position 1.2 projected lower (more conservative) USE values for each of these materials.

The staff identified discrepancies and insufficient information for the USE input parameters. Therefore, the staff requested (RAI 4.2.2-1) that the applicant provide complete material descriptions and describe the procedures used to determine the chemistry data and initial USE for the extended beltline materials to demonstrate that it has applied consistent approaches for both the beltline and the extended beltline materials.

By letter dated April 17, 2012, the applicant provided the requested information in revised Tables 4.2-4 and 4.2-5 for Units 1 and 2, respectively. As discussed in Section 4.2.2.2, the staff reviewed the copper values in Tables 4.2-2 and 4.2-3 and determined that the values were acceptable. The copper values in Tables 4.2-4 and 4.2-5 are identical to the values in Tables 4.2-2 and 4.2-3 for Units 1 and 2, respectively. The staff compared the unirradiated USE values to the UFSAR. Initial USE values for the Units 1 and 2 bottom head torus longitudinal welds were obtained from measured values recorded in weld certification records. For welds lacking measured values, generic USE values from NRC-approved report CEN-622-A, "Generic Upper-Shelf Values for Linde 1092, 124 and 0091 Reactor Vessel Welds, CEOG Task 839," were used. The generic "mean -2 sigma" values for Linde 0091 and Linde 124 flux types are 101 ft-lbs and 84 ft-lbs, respectively. The staff compared these generic values to measured unirradiated USE values for E-8018 welds at other plants and concluded the generic values are appropriate for estimating the initial USE values of E-8018 welds in the STP RV in lieu of measured unirradiated USE values. Therefore, the staff concluded that the unirradiated USE values in the revised Tables 4.2-4 and 4.2-5 for Units 1 and 2, respectively, are acceptable. The concerns in RAI 4.2.2-1 related to USE are resolved.

The staff used Position 1.2 of RG 1.99, Revision 2, and determined that, based upon the analysis for all beltline and extended beltline materials, the applicant's projected USE values were determined conservatively and resulted in 71 ft-lbs for the limiting material (intermediate shell R1606-2) for Unit 1, and 72 ft-lbs for the limiting materials (lower shell to lower head torus circumferential weld and nozzle (upper) shell to intermediate shell circumferential weld) for Unit 2.

By letter dated December 11, 2012, the applicant revised LRA Section 4.2.3. The revised section specifies the limiting material for each reactor vessel (for Unit 1, intermediate shell R1606-2, and for Unit 2, the lower shell to lower head torus circumferential weld and the nozzle (upper) shell to intermediate shell circumferential weld) and states that the embrittlement projections for these limiting materials also bound the other materials above and below the beltline. The staff finds the LRA section revision acceptable and consistent with its own confirmatory calculations.

In summary, the staff has determined that the Units 1 and 2 beltline and extended beltline materials have projected USE values at 1/4 T greater than 50 ft-lbs and, pursuant to 10 CFR 54.21(c)(1)(ii), meet the 10 CFR Part 50, Appendix G, USE requirement to the end of the period of extended operation; therefore, the applicant's USE analyses are acceptable.

4.2.3.3 UFSAR Supplement

LRA Section A3.1.3 provides the UFSAR supplement summarizing the USE TLAA. The staff reviewed LRA Section A3.1.3, consistent with the review procedures in SRP-LR Section 4.2.3.2, which state that the applicant should provide a summary description of the evaluation of the RV neutron embrittlement TLAA and provide information equivalent to SRP-LR Table 4.2-1. Based on its review of the UFSAR supplement, the staff determines that the applicant provided an adequate summary description of its actions to address USE, as required by 10 CFR 54.21(d).

4.2.3.4 Conclusion

On the basis of its review of the LRA and the applicant's response to RAI 4.2.2-1 (related to USE), the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the USE analyses have been projected to the end of the period of extended operation and will meet the criteria defined in Appendix G to 10 CFR Part 50. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.4 Pressure-Temperature Limits

4.2.4.1 Summary of Technical Information in the Application

LRA Section 4.2.4 describes the applicant's TLAA for the evaluation of the RV pressure-temperature (P-T) limits for the period of extended operation. The applicant developed the adjusted RT values (ART values) at the 1/4T and 3/4T RV wall thickness locations using neutron fluences for those locations. The current P-T limit curves are valid through 32 EFPY.

The LRA states that the Reactor Vessel Surveillance Program (LRA Section B2.1.15) monitors RV embrittlement. This program provides data to update the P-T limits; therefore, it permits the applicant to manage the P-T limits going forward in accordance with 10 CFR 54(c)(1)(iii). The applicant will submit updates to the P-T limits for STP, Units 1 and 2, to the NRC at the appropriate time to comply with 10 CFR Part 50, Appendix G.

The applicant dispositioned the RV P-T limits TLAA in accordance with 10 CFR 54.21(c)(iii), that the effects of aging on the intended functions will be adequately managed for the period of extended operation.

4.2.4.2 Staff Evaluation

The staff reviewed LRA Section 4.2.4 and the P-T limits TLAA to confirm, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the P-T limits will be adequately managed by the applicant for the period of extended operation. The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with the review procedures in SRP-LR Section 4.2.3.1.3.3, which state that the updated P-T limits for the period of extended operation must be available prior to entering the period of extended operation. The staff noted that the P-T limits are contained in the applicant's TS, Section 3.4.9.1, "Pressure/Temperature Limits, Reactor Coolant System."

Prior to the expiration of the current P-T limit curves for STP, Units 1 and 2 (32 EFPY), the applicant is required to submit revised P-T limit curves in accordance with 10 CFR Part 50, Appendix G, considering the impact of all reactor coolant system (RCS) components, the increase of the limiting ART, and plant-specific embrittlement information from additional surveillance data provided by the RV Surveillance Program.

Ferritic RCPB components that are <u>not</u> RV beltline shell materials (i.e., consistent with GALL Report definitions, those RV components that will receive neutron fluence less than 1.0 x 10^{17} $n/cm^{2,}$) may have calculated P-T curve limits, irrespective of the components' neutron fluence values, that are more restrictive than those calculated for RV beltline shell materials. For example, this could be due to such factors as a component that exhibits significantly higher stresses, due to having a complex geometry, than components in the beltline, or an RCPB component having a higher initial nil-ductility reference transition temperature, which leads to a more restrictive P-T limitation than those for RV shell components. The staff noted that the information in LRA Section 4.2.2.4 describing the applicant's approach for revising its P-T limit curves beyond their currently-approved 32 EFPY did not address how the approach considers all ferritic RCPB materials and the most restrictive service temperatures among all ferritic RCPB materials, consistent with the requirements of 10 CFR Part 50, Appendix G.

By letter dated June 25, 2012, the staff issued RAI 4.2.4-1, requesting that the applicant address this issue as it relates to its P-T curve methodology and explain how it will manage its P-T limit curves during the period of extended operation.

By letter dated July 17, 2012, the applicant stated the following:

> 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 [Part] 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.

In addition, the applicant revised LRA Section 4.2.4 and Appendix A3.1.4 "Pressure–Temperature (P-T) Limits" to describe how the P-T limit curves will be revised to be consistent with the requirements of 10 CFR Part 50, Appendix G, during the period of extended operation. Enclosure 2 to the July 17, 2012, letter provides the line-in/line-out changes to LRA Section 4.2.4 and Appendix A3.1.4. These changes demonstrate that the approach for revising the P-T limit curves beyond 32 EFPY will be consistent with the requirements of 10 CFR Part 50, Appendix G. The staff's concerns in RAI 4.2.4-1 are resolved.

Based on this review, the staff finds that the applicant's plan to manage the P-T limits in accordance with 10 CFR 54.21(c)(1)(iii) is acceptable because revised P-T limit curves (as contained in TS 3.4.9.1) meeting the requirements of 10 CFR 50.60 and 10 CFR Part 50, Appendix G, will be implemented by the license amendment process (i.e., through revision of the plant's TS).

4.2.4.3 UFSAR Supplement

LRA Section A3.1.4, as revised by the applicant in its letter dated July 17, 2012, provides the UFSAR supplement summarizing the P-T limits TLAA. The staff reviewed LRA Section A3.1.4, consistent with the review procedures in SRP-LR Section 4.2.3.2, which state that the applicant should provide a summary description of the evaluation of the RV neutron embrittlement TLAA and provide information equivalent to SRP-LR Table 4.2-1. Based on its review of the UFSAR supplement, as revised, the staff determines that the applicant provided an adequate summary description of its actions to address P-T limits, as required by 10 CFR 54.21(d).

4.2.4.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the P-T limits will be adequately managed by the applicant for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.5 Low Temperature Overpressure Protection

4.2.5.1 Summary of Technical Information in the Application

LRA Section 4.2.5 describes the applicant's TLAA for the evaluation LTOP. The LRA states that LTOP is required by TS Limited Condition for Operation (LCO) 3.4.9.3 and is provided by the cold overpressure mitigation system (COMS), which opens the pressurizer power-operated relief valves (PORVs) at a setpoint calculated to prevent violation of the P-T limits. The LRA states that changes to the P-T limit curves require an evaluation of the LTOP temperature and PORV pressure setpoints, and that the LTOP analyses depend only on ART values at critical locations and the P-T limits, and not on any other time-dependent values.

The applicant dispositioned the LTOP TLAA in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed for the period of extended operation.

4.2.5.2 Staff Evaluation

The staff reviewed LRA Section 4.2.5 and the LTOP TLAA, and the corresponding disposition, consistent with the review procedures in SRP-LR Section 4.2.3.1.3 to confirm, pursuant to 10 CFR 54.21(c)(1)(iii), that LTOP will be adequately managed by the applicant for the period of extended operation. The staff noted that the LTOP requirements are contained in the applicant's TS, Section 3.4.9.3, "Overpressure Protection Systems."

LRA Section 4.2.4 states that the current P-T limits are projected and approved through 32 EFPY. Prior to the expiration of the current P-T limit curves, the applicant is required to submit revised P-T limit curves in accordance with 10 CFR Part 50, Appendix G, considering all applicable RCS materials, the increase of the limiting ART, and plant-specific embrittlement information from additional surveillance data provided by the Reactor Vessel Surveillance Program. Revised P-T limit curves will require evaluation of the LTOP temperature and PORV pressure setpoints; the revised P-T limit curves and the revised ART values are the only time-dependent inputs to the LTOP analyses.

Based on this review, the staff finds that the applicant's plan to manage LTOP accordance with 10 CFR 54.21(c)(1)(iii) is acceptable because it meets the requirements of 10 CFR 50.60 and 10 CFR Part 50, Appendix G, and will be implemented by the license amendment process (i.e., through revision of TS 3.9.4.3 and the associated TS bases).

4.2.5.3 UFSAR Supplement

LRA Section A3.1.5 provides the UFSAR supplement summarizing the LTOP TLAA. The staff reviewed LRA Section A3.1.5, consistent with the review procedures in SRP-LR Section 4.2.3.2, which state that the applicant should provide a summary description of the evaluation of the RV neutron embrittlement TLAA and provide information equivalent to SRP-LR Table 4.2-1. Based on its review of the UFSAR supplement, the staff determines that the applicant provided an adequate summary description of its actions to address LTOP, as required by 10 CFR 54.21(d).

4.2.5.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that LTOP will be adequately managed by the applicant for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3 Metal Fatigue Analysis

LRA Section 4.3 provides the applicant's assessment of metal fatigue as a TLAA for license renewal. The applicant's assessment is divided into the following major subsections of LRA Section 4.3:

- Fatigue cycles and the monitoring activities performed by the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program (Section 4.3.1)
- ASME Code Section III Class I fatigue analysis of vessels, piping, and components (Section 4.3.2)
- ASME Code Section III Subsection NG fatigue analysis of reactor pressure vessel internals (Section 4.3.3)
- Effects of the RCS environment on fatigue life of piping and components (Section 4.3.4)
- Assumed thermal cycle count for allowable secondary stress range reduction factor in ANSI B31.1 and ASME Code Section III Class 2 and 3 piping (Section 4.3.5)
- ASME Code Section III fatigue analysis of metal bellows and expansion joints (Section 4.3.6)

The staff's evaluation of LRA Section 4.3.1 is documented in SER Section 4.3.1.2. The description and staff's evaluation of above-listed Sections 4.3.2 to 4.3.6 are documented in SER Sections 4.3.2 to 4.3.6, respectively.

4.3.1 Metal Fatigue of Reactor Coolant Pressure Boundary Program

4.3.1.1 Summary of Technical Information in the Application

LRA Section 4.3.1 describes the design transients and associated number of design cycles that are significant fatigue contributors in the applicant's assessment of metal fatigue TLAAs. LRA Section 4.3.1 also indicates that the Metal Fatigue of Reactor Pressure Coolant Boundary Program (B3.1) is required by STP TSs 5.7.1 and 6.8.3.f. UFSAR Section 3.9.1 discusses the design cycles as historical numbers used in the original design basis fatigue evaluations for equipment design purposes. The ASME Code does not require inclusion of emergency or faulted conditions in fatigue evaluations. Therefore, the Metal Fatigue of Reactor Coolant Pressure Boundary Program does not monitor emergency and faulted conditions.

The Metal Fatigue of Reactor Pressure Coolant Boundary Program tracks the occurrences of the transients listed in LRA Table 4.3-2 and manages the CUFs by using either the cycle-counting monitoring method or cycle-based fatigue monitoring method. The Metal Fatigue of Reactor Coolant Pressure Boundary Program ensures that the numbers of transients actually experienced during the period of extended operation remain below the assumed number or that appropriate corrective actions maintain the design and licensing basis.

The applicant reviewed operating history of STP, Units 1 and 2, from initial startup to year-end 2008 in order to baseline the transient event count for the Metal Fatigue of Reactor Coolant Pressure Boundary Program. These baselined results were then extrapolated to 60 years. LRA Table 4.3-2 includes the accumulated cycle counts through 2008 and the projections to 60 years. The LRA states that the cycle projections are based on a long-term weighting and short-term weighting to obtain the most accurate projections of the future behavior of that event. These projections are intended to be a best estimate of the actual cycles expected.

4.3.1.2 Staff Evaluation

The staff reviewed LRA Section 4.3.1 to confirm that the transients that are significant fatigue contributors are monitored to ensure that the applicant's fatigue evaluations remain valid. The staff also reviewed the methodology used by the applicant to obtain the 60-year projections. The staff's evaluation of the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program is documented in the SER Section 3.0.3.2.28.

LRA Table 4.3-2 indicates that the current cycle count for Transient 41 (Charging Trip with Prompt Return to Service) for Unit 1 is 10 as of the end of 2008. During its audit, the staff reviewed the applicant's design basis documents and noted that the cycle count for Transient 41 for Unit 1 was 11 as of April 2005. By letter dated September 22, 2011, the staff issued RAI 4.3-1 requesting that the applicant justify the discrepancy and provide the correct current cycle count and, as applicable, the 60-year projected cycles for Transient 41 for Unit 1.

In its response dated November 21, 2011, the applicant stated that its corrective action document noted 11 occurrences of the loss of charging events, including the April 12, 2005, event where letdown was temporarily reduced. Upon further review of plant data recordings when developing the baseline cycles for license renewal (LRA Table 4.3-2), the applicant determined that the April 12, 2005, event was not a loss of charging event because charging flow remained above 35 gallons per minute, while the flow rate varied during the day, for the entire day. The applicant confirmed that the correct current cycle count for Transient 41 as of the end of 2008 is 10 occurrences. The staff noted that the applicant is continuing to manage this transient, which is used in metal fatigue evaluations, during the period of extended operation with its Metal Fatigue of Reactor Coolant Pressure Boundary Program that ensures the validity of its fatigue analyses or calculates accrued usage to ensure the Code design limit of 1.0 is not exceeded.

The applicant also stated that the April 12, 2005, event should be classified as “Charging Flow Step Decrease and Return to Normal,” which assumes 24,000 occurrences for the design number of cycles, and its Metal Fatigue of Reactor Coolant Pressure Boundary Program does not specifically count this event because the number of assumed cycles is far greater than the number expected over 60 years. However, it was not clear to the staff why this transient does not need to be monitored by the applicant’s program to ensure any fatigue analysis that assumed the occurrence of this transient remains valid. By letter dated January 31, 2012, the staff issued RAI 4.3-1a (followup) requesting that the applicant clarify the baseline number of events up to the end of 2008 and the 60-year projected cycles for the charging flow step decrease and return to normal transient.

In its response dated February 16, 2012, the applicant stated that “charging flow step decrease and return to normal” transient is not included in the baseline because the transient is not monitored. Furthermore, this transient occurs when there is a power change, typically during plant heatup and cooldown, and the estimated number of events based on the plant heatup and cooldown events that have occurred up to the year ending of 2008 are 87 (Unit 1) and 55 (Unit 2). The applicant estimated that the 60-year projected events would be 172 (Unit 1) and 154 (Unit 2). The staff noted that there is significant margin between the expected number of cycles through the period of extended operation and 14,400 cycles and finds it reasonable that sufficient margin exists to account for unanticipated shutdowns or power reductions. In addition, the staff finds it reasonable that the “charging flow step decrease and return to normal” transient is not monitored because the applicant’s units do not practice load following operation, but operate as base-loaded plants. The staff also noted that the units’ projected occurrences are far less than the limiting value of 14,400 cycles identified in the applicant’s response to RAI 4.3-2 dated November 21, 2011.

The staff finds it reasonable that the “charging flow step decrease and return to normal” transient does not require monitoring by the Metal Fatigue of Reactor Coolant Pressure Boundary Program because the transient is correlated with the occurrences of the heatup and cooldown transients that are monitored, and there is substantial margin between the 60-year projected occurrence (less than 200) and the limiting value of 14,400. Therefore, the staff finds the applicant’s response to RAI 4.3-1a acceptable. The staff’s concern described in RAI 4.3-1a (followup) is resolved.

The staff finds the applicant’s response to RAI 4.3.1 acceptable because the applicant clarified and justified the discrepancy for the cycle count of Transient 41 based on actual plant data and the applicant’s Metal Fatigue of Reactor Coolant Pressure Boundary Program is monitoring this transient. The staff’s concern described in RAI 4.3-1 is resolved.

LRA Section 4.3.1.2 states that the occurrences of the transients listed in LRA Table 4.3-2 are tracked, and the CUFs at the locations listed in LRA Table 4.3-1 are managed using either the cycle counting monitoring method or the cycle-based fatigue (CBF) monitoring method. In addition, the LRA states that the most limiting number of cycles for each transient is listed as the “Program Limiting Value” and will be used for the Metal Fatigue of Reactor Coolant Pressure Boundary Program. It was not clear to the staff whether the components identified in LRA Table 4.3-1 are the only components monitored by the Metal Fatigue of Reactor Coolant

Pressure Boundary Program to manage cumulative fatigue damage and whether there are any TLAAs or evaluations other than the environmentally-assisted fatigue (EAF) evaluations that use the 60-year projected cycles.

By letter dated September 22, 2011, the staff issued RAI 4.3-11 requesting that the applicant clarify the monitoring method used by the Metal Fatigue of Reactor Coolant Pressure Boundary Program for the components and locations in which the applicant's metal fatigue TLAAs were dispositioned in accordance with 10 CFR 54.21(c)(1)(iii). The staff also asked the applicant to clarify whether the cycle-counting monitoring method accounts for the use of the 60-year projected cycles for those TLAAs or evaluations other than the EAF evaluations.

In its response dated November 21, 2011, the applicant stated that the components identified in LRA Table 4.3-1 are monitored by cycle-based fatigue monitoring, and all other components that are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii) are monitored by cycle counting. In addition, the applicant clarified that there are no other fatigue analyses, other than the EAF evaluations, which use the 60-year projected cycles. The staff noted that this method provides a "real-time" usage factor and allows the applicant to ensure that the ASME Code design limit of 1.0 is not exceeded, consistent with the recommendations of GALL Report AMP X.M1. This method allows the determination of cumulative fatigue usage for a specific location based on the actual number of transient occurrences and the assumption that the fatigue usage contributed by each transient is equal to the design transient severity. The staff finds the applicant's use of cycle-based fatigue monitoring to be capable of managing metal fatigue because it periodically calculates cumulative fatigue usage based on the cycle counts and design transient severity to ensure the design limit is not exceeded during the period of extended operation. The staff's review of the Metal Fatigue of Reactor Coolant Pressure Boundary Program, specifically the management of cumulative fatigue usage, is documented in SER Section 3.0.3.2.28. The staff noted that the EAF evaluations that use the 60-year projected cycles will be monitored by CBF. Since there are no other fatigue analyses that rely on the 60-year projected cycles, the staff finds it appropriate that the applicant's program limiting values on number of cycles does not need to be based on these projected cycles.

Based on its review, the staff finds the applicant's response to RAI 4.3-11 acceptable because the applicant clarified that the CBF method, which calculates real-time usage to ensure that the Code design limit is not exceeded, is used for those components identified in LRA Table 4.3-1. Additionally, the cycle counting method is used for all other components to ensure on an ongoing basis that the analysis that calculated the CUF to be less than 1.0 remains valid. Both methods are consistent with the recommendations of GALL Report AMP X.M1 to manage cumulative fatigue damage. The staff's concerns in RAI 4.3-11 are resolved.

LRA Section 4.3.1.2 states that the Metal Fatigue of Reactor Coolant Pressure Boundary Program tracks the occurrences of the transients listed in LRA Table 4.3-2, which includes the following transients:

- Transient 5, "Unit Loading at 5% of Full Power/min"
- Transient 6, "Unit Unloading at 5% of Full Power/min"
- Transient 10, "Steady State Fluctuations, Initial"
- Transient 11, "Steady State Fluctuations, Random"
- Transient 15, "Unit Loading Between 0-15% of Full Power"
- Transient 16, "Unit Unloading Between 0-15% of Full Power"
- Transient 17, "Boron Concentration Equalization"

The staff noted that LRA Table 4.3-2 does not provide baseline numbers of cycles for Units 1 and 2 for the transients listed above; therefore, it is not clear how the Metal Fatigue of Reactor Coolant Pressure Boundary Program tracks the occurrences of these transients. Since 60-year projections were not provided for the transients listed above, it was not clear to the staff whether they were used as parts of the applicant's EAF CUF calculations.

By letter dated September 22, 2011, the staff issued RAI 4.3-13 requesting that the applicant justify how the Metal Fatigue of Reactor Coolant Pressure Boundary Program tracks the occurrences of Transients 5, 6, 10, 11, 15, 16, and 17 without having a baseline number of cycles for each of them. The staff also asked the applicant to clarify whether these transients were included into the EAF CUF calculation.

In its response dated November 21, 2011, the applicant stated that transients 5, 6, 10, 11, 15, 16, and 17 are not projected; therefore, they are not tracked by the Metal Fatigue of Reactor Coolant Pressure Boundary Program. The applicant explained that Transient 17, "Boron Concentration Equalization," occurs following any large change in boron concentration in the RCS by initiating spray in order to equalize boron concentration between the RCS loops and the pressurizer. For design purposes, it is assumed that this operation is performed after each load change in the load-following design cycle, and Transient 17 is assumed to coincide with Transients 5 and 6. Footnote 4 of LRA Table 4.3-2 indicates that Transients 15 and 16 are transients for a load-following plant. The applicant further clarified that it does not operate as a load-following plant, which set the power level of a unit in accordance with the electrical grid. The applicant stated that LRA Table 4.3-2, Footnote 5, will be revised to note that Transient 17 is a load-following transient.

The staff noted that the design number of cycles for Transients 5, 6, 15, 16, and 17 were based on the assumption that the plant was a load-follower. The applicant explained in the footnotes of LRA Table 4.3-2, and further clarified in its response, that the units were not load-followers. The staff finds it acceptable that the applicant does not monitor these transients because the design number of cycles was based on load-following operations. Also, since the units are not load-followers, one would not expect that the design number of cycles would be approached.

The applicant also stated in its response that Transients 10 and 11 are both subcategories of steady-state fluctuations. Transient 10 identifies fluctuations that are assumed to occur only during the first 20 full-power months of operation; therefore, Transient 10 is not applicable for future operation and does not need to be managed for fatigue. The applicant stated that the number of cycles for Transient 11 is below the endurance limit of the ASME Code fatigue curves; therefore, Transient 11 does not need to be managed for fatigue. When compared to the ASME fatigue curve, the staff was unable to determine the meaning of the applicant's statement regarding Transient 11. The staff held a conference call on August 9, 2012 with the applicant in order for the staff to obtain clarification as to the applicant's intended response. The applicant stated during the call, as documented in the conference call summary (ADAMS Accession No. ML12227A560), that the intent of the statement was to read as follows: "The stress range of Transient 11 is below the endurance limit of the ASME fatigue curves, therefore this transient is not significant to fatigue." Based on this clarification, the staff finds it reasonable that if the stress caused by Transient 11 is less than the S_a associated with the endurance limit on the ASME Code fatigue curves then fatigue life can be considered infinite because the alternating stress from this transient is less than the stress that would result in metal fatigue. Therefore, the staff determines that this transient does not need to be monitored by the Metal Fatigue of Reactor Coolant Pressure Boundary Program. The staff also finds it acceptable that Transient 10 is not monitored by the Metal Fatigue of Reactor Coolant Pressure Boundary

Program because it was only applicable during the first 20 full-power months of operation and is not applicable for future operation.

The applicant clarified that if a transient is not projected for the period of extended operation, then the design number of events is used in the EAF CUF calculations. The applicant stated that Transients 5, 6, 10, 11, and 17 are used in the hot leg surge nozzle EAF CUF calculation. In addition, Transients 5, 6, 10, 11, 15, 16, and 17 have a negligible effect on EAF CUF calculations for the charging nozzles and are not included in those calculations. The staff finds it conservative that the above-mentioned transients were included in the hot leg surge nozzle EAF CUF calculation because the design number of events for a load-following plant was assumed to occur even though the applicant's site does not practice load-following operation. Since these transients were meant for a plant designed for load-following operation, the staff also finds it reasonable that the above-mentioned transients were not included in the charging nozzle EAF CUF calculations because the applicant's site does not practice load following operation and operates as a base-loaded plant.

Based on its review, as described above, the staff finds the applicant's response—to clarify why Transients 5, 6, 10, 11, 15, 16, and 17 are not monitored by the Metal Fatigue of Reactor Coolant Pressure Boundary Program—acceptable. The staff's concern described in RAI 4.3-13 is resolved.

LRA Tables 4.3-2 provides the baseline and 60-year projected numbers of cycle for STP, Units 1 and 2, for the following transients:

- Transient 19, "Primary Side Leak Test"
- Transient 22, "Turbine Roll Test"
- Transient 43, "Primary Side Hydrostatic Test"
- Transient 44, "Secondary Side Hydrostatic Test"

The staff noted that LRA Section 4.3.4 states that a method used to reduce the EAF CUF values includes using 60-year projected occurrences of transient events in LRA Table 4.3-2, instead of using the 40-year design number of events. For the transients listed above, LRA Table 4.3-2 indicates that these transients are not expected to occur again through 60 years of operation, except Transient 19 for Unit 2. Since these projections may have been used in reducing the EAF CUF, it is not clear why these transients are not expected to occur again and whether this is conservative.

By letter dated September 22, 2011, the staff issued RAI 4.3-14 requesting that the applicant justify why Transients 19 (except for Unit 2), 22, 43, and 44 are not expected to occur again through 60 years of operation. The staff also asked the applicant to justify that the use of these projections is conservative for the EAF CUF calculations.

In its response dated November 21, 2011, the applicant stated that Transients 19, 22, 43 and 44 are tests performed during initial startup, and no more tests are expected. The applicant also explained that for Unit 2 Transient 19, it chose to project one assumed event since no cycles have accumulated to date. In addition, the applicant stated that these projections were used in the EAF CUF calculations, but these startup tests are not expected to be performed again. Since these are test transients that are performed during initial startup, the staff finds it reasonable that the applicant assumed these transients would not occur again during the period of extended operation. However, the staff also noted that the applicant is not relying on the 60-year projections to justify that its fatigue analyses are valid for the period of extended operation. The applicant is continuing to manage the cumulative fatigue damage during the period of extended operation with its Metal Fatigue of Reactor Coolant Pressure Boundary Program that ensures the validity of its fatigue analyses or calculates accrued usage to ensure the Code design limit of 1.0 is not exceeded. The applicant stated that if these transients were to occur again, they would be tracked and incorporated in CBF generated EAF CUFs, which will ensure that corrective actions are taken as the EAF CUFs approach the action limit and the Code design limit.

The staff finds the applicant’s response acceptable because the applicant clarified that these transients were performed as part of the initial start-up process for both units and are not expected to occur again, and the applicant has not relied on these 60-year projections to justify its fatigue analyses are valid for the period of extended operation. In the event these test transients were to occur again, the applicant’s Metal Fatigue of Reactor Coolant Pressure Boundary Program is monitoring these transients. The staff’s concern described in RAI 4.3-14 is resolved.

LRA Section 4.3.1.3 states that the applicant captured all the necessary transient events, and the event history was taken primarily from existing manual or computer-assisted cycle counting records. LRA Section 4.3.1.3 also states that the baseline cycle counting results were projected to 60 years, and the projected cycle counts were computed based on the actual accumulation history since the start of plant life. In addition, the cycle projections are based on long-term weighting (LTW) and short-term weighting (STW) to obtain the “most accurate projections of the future behavior of that event.”

It was not clear to the staff if, during the applicant’s review of the transient event history, the applicant had confirmed that the severity of the transients that occurred was bounded by the severity of the design transient. In addition, since the applicant used the 60-year transient projections in its EAF fatigue analyses, additional information was needed about the LTW and STW used by the applicant in its projection methodology for the staff to determine if the methodology used was appropriate and reasonable.

By letter dated September 22, 2011, the staff issued RAI 4.3-12, requesting that the applicant describe actions taken to confirm that the severity of all transients that have occurred is bounded by the design severity of the transient and to describe the LTW and STW used for the 60-year projection methodology of design transients. The staff also asked the applicant to justify that this 60-year projection methodology is reasonable.

In its response dated November 21, 2011, the applicant stated that it did not confirm that the severity of all transients that have occurred is bounded by the design severity of the transient during the preparation of the LRA. However, the plant operating procedures and TSs are designed to ensure that the severity of plant events is bounded by those described in the design analyses. The applicant explained that its current procedure requires a daily screening of transients that have occurred. The applicant further explained that a transient-specific datasheet is completed to record the plant’s conditions during the event, and such information is forwarded to system engineering for validation and review. The staff finds it acceptable that the applicant did not confirm the severity of all past transients during the development of the LRA because the applicant’s procedures and TSs ensure that transients are recorded on a daily basis and will receive validation and review by the applicant’s engineering staff at the time the transients occur.

The applicant also stated that the LTW and STW values used for each transient are estimated by taking into account the history of each transient, number of cycles, distribution, and qualities of the transient itself. In general, the applicant assumed that the short-term history was three times more likely to predict future performance than the long-term history (i.e., STW=3, LTW=1), and the short-term is 10 years, which is approximately one-third of the plant operating period. The applicant identified exceptions, which are those transients that occur randomly with a low number of occurrences and those that only occurred during initial plant testing. The applicant identified the transients that did not rely on the 3-to-1 short-term-to-long-term ratio described above and provided the corresponding STW, LTW, and short-term period in a table in its response to RAI 4.3-12.

The applicant also stated that the short-term-to-long-term ratio projection method is not used for transients that had never occurred, in which case at least one event was assumed for future operation. The staff noted that the applicant has not relied upon this methodology to determine the 60-year projections to justify that any fatigue analysis is valid during the period of extended operation. The staff further noted that the applicant is managing the validity of its design basis fatigue analyses (which did not use the 60-year projected cycles) and ensuring that the CUF for those components selected for EAF does not exceed the Code design limit of 1.0 with its Metal Fatigue of Reactor Coolant Pressure Boundary Program on an ongoing basis. The staff finds that the applicant's methodology for determining 60-year projections provides an estimate of the margin between the number of cycles that have been used in the fatigue analyses and the expected number of cycles for 60-years of operation.

The staff finds the applicant's response acceptable because the applicant's procedures and TSs have ensured, and will ensure, that the severity of a transient does not exceed the assumptions in the fatigue analysis. In addition, the staff finds the response acceptable because the applicant is not relying on the 60-year projections to justify that its fatigue analysis is valid for the period of extended operation. Instead, the applicant is continuing to manage the cumulative fatigue damage during the period of extended operation with its Metal Fatigue of Reactor Coolant Pressure Boundary Program, which ensures the validity of its fatigue analyses or calculates accrued usage to ensure the Code design limit of 1.0 is not exceeded. The staff's concern described in RAI 4.3-12 is resolved.

Based on its review, the staff finds the applicant has demonstrated that it monitors all transients that cause cyclic strains, which are significant contributors to the fatigue usage factor with its Metal Fatigue of Reactor Coolant Pressure Boundary Program, such that corrective actions are taken prior to the design limit exceeding 1.0, including environmental effects when applicable.

4.3.1.3 UFSAR Supplement

LRA Sections A2.1 and A3.2 provide the UFSAR supplement summarizing the applicant's basis of its fatigue analyses and describing its Metal Fatigue Reactor Coolant Pressure Boundary Program to ensure that the numbers of transients actually experienced remain below the assumed number. The staff reviewed LRA Sections A2.1 and A3.2, consistent with the review procedures in SRP-LR Section 4.3.3.3, which state that the reviewer should confirm that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the UFSAR supplement, the staff finds that it meets the acceptance criteria in SRP-LR Section 4.3.2.3. Additionally, the staff determines that the applicant provided an adequate summary description for its Metal Fatigue Reactor Coolant Pressure Boundary Program to monitor the numbers of transients actually experienced, as required by 10 CFR 54.21(d).

4.3.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an adequate description and acceptable basis for monitoring design transients and cycles with its Metal Fatigue of Reactor Coolant Pressure Boundary Program. The program ensures that corrective actions are taken prior to exceeding the design limit during the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the monitoring bases of transients and design cycles, as required by 10 CFR 54.21(d).

4.3.2 Fatigue of ASME Code Class 1 Components

4.3.2.1 Reactor Pressure Vessel, Nozzles, Head, and Studs

4.3.2.1.1 Summary of Technical Information in the Application

LRA Section 4.3.2.1 describes the applicant's TLAA for fatigue of the RPV, nozzles, head, and studs. LRA Section 4.3.2.1 states that the Units 1 and 2 RPVs are designed to ASME Code Section III, 1971 edition with addenda through summer 1973. The STP vessels were built and analyzed for the assumed 40-year number of transient cycles. The applicant subdivided the TLAA discussion into three cases: (1) the replacement reactor vessel closure heads (RRVCHs); (2) the repaired Bottom-mounted instrument (BMI) nozzles; and (3) all remaining components of the RPV, nozzles and studs.

The applicant replaced the Units 1 and 2 RPV heads in the fall of 2009 and spring of 2010, respectively. The RRVCHs were designed to ASME Code, Section III, 1989 edition (no addendum). The applicant stated that the fatigue usage factor (i.e., CUF) analyses for the RPV heads and any similarly-replaced-and-analyzed appurtenances are analyzed for the design number of transient cycles starting from the time of installation. The applicant dispositioned the fatigue usage factor analyses in accordance with 10 CFR 54.21(i), that the analyses remain valid through the period of extended operation.

Pressure-retaining and support components of the RPV are listed in LRA Table 4.3-3 and subject to a fatigue usage factor analysis in accordance with ASME Code Section III. The applicant updated the fatigue usage factor analysis to incorporate redefinitions of loads and design basis events, operating changes, power uprate, replacement steam generators, and minor modifications. The applicant concluded that the currently applicable fatigue usage factor analyses of the reactor pressure boundary and its supports are TLAAs, and dispositioned the analyses in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed for the period of extended operation.

The Unit 1 bottom-mounted instrument (BMI) nozzles are made of Alloy 600 and are attached to the clad inner surface of the RV bottom head by Alloy 182 J-groove welds. During refueling outage 11 (1RE11, spring 2003), the applicant discovered leaks at Unit 1 BMI nozzles 1 and 46, which were repaired by the "half-nozzle" method. A half-nozzle repair leaves the existing flaw(s) in the original, inner-wall J-groove weld in place. In addition, the repair exposes a small portion of the low-alloy steel base metal of the lower RV head to reactor coolant and, therefore, to possible corrosion. These repairs were evaluated for growth of postulated residual flaws due to fatigue and corrosion. The flaw growth analysis, corrosion analysis, and fatigue usage factor analysis qualify the repaired BMI nozzles for operation from the time of the repair through the period of extended operation. These are the only Alloy 600 half-nozzle repairs performed at

STP. The applicant concluded that the analyses for the two BMI nozzle repairs are TLAAs and dispositioned them in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid during the period of extended operation.

4.3.2.1.2 Staff Evaluation

The staff reviewed LRA Section 4.3.2.1 and the fatigue usage factor or crack growth analyses, or both, for the RPV, head, nozzles, or studs, to confirm pursuant to 10 CFR 54.21(c)(1)(i) or 10 CFR 54.21(c)(1)(ii) that the analyses remain valid through the period of extended operation or are projected to the end of the period of extended operation. Otherwise, the staff confirmed that the effect of fatigue will be adequately managed for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii). The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with the review procedures in SRP-LR Sections 4.3.2.1 and 4.7.3, which state that the review of the TLAA provides assurance that the aging effect is properly addressed through the period of extended operation. The staff evaluated three major components—the RRVCH with associated control rod drive mechanism (CRDM) penetration nozzles, the BMI nozzles, and the remaining RPV components as listed in LRA Table 4.3-3.

Reactor Vessel Closure Head. By letter dated April 14, 2011, the staff issued RAI 4.3.2.1-1, requesting that the applicant discuss the condition of the RRVCHs in both units and measures that have been taken to minimize the degradation in CRDM penetration nozzles. By letter dated May 12, 2011, the applicant responded that no relevant indications were identified during the pre-service inspection of the Unit 1 and 2 RRVCHs. Currently, the applicant uses ASME Code Section XI, 2004 edition (no addenda) for the Inservice Inspection (ISI) Program.

Based on the third interval 10-year ISI Program, the applicant performs visual examinations of the RRVCHs every third refueling outage. The RRVCH and CRDM nozzles and partial penetration welds are monitored by performing volumetric or surface examinations (or both) once per 10-year ISI interval. To minimize degradation in CRDM penetration nozzles, the applicant has used thermally treated Alloy 690 material for CRDM penetrations, Alloy 52 weld filler metal for J-groove welds, and automatic J-groove welding technology (including water-cooling to improve stress distribution through the CRDM adapter wall).

The staff noted that the RRVCHs use material that is less susceptible to pressurized water stress corrosion cracking (PWSCC) and welding technology that would produce sound welds. The applicant has followed the ASME Code ISI Program to monitor potential degradation in the RRVCH, and the staff finds that aging effects of the RRVCH will be managed by inspection satisfactorily. Based on the above evaluation, the staff's concern as described in RAI 4.3.2.1-1 is resolved.

In RAI 4.3.2.1-5, the staff asked the applicant to provide the basis for its conclusion that the fatigue usage factor analyses for the RRVCH are valid for the period of extended operation. By letter dated May 12, 2011, the applicant responded that the Unit 1 and 2 CRDM pressure housings, the core exit thermocouple nozzle assemblies (CETNAs), and the internal disconnect devices (IDDs) were replaced with the RRVCHs in 2009 and 2010, respectively. The new CRDMs and CETNAs were qualified for 40 years. This means that the RRVCHs are qualified and applicable for use up to 2049 and 2050 for Units 1 and 2, respectively. The renewed operating licenses for STP, Units 1 and 2, would expire in 2047 and 2048, respectively, and thus the analysis is valid through the period of extended operation. The staff finds that the fatigue usage factor analyses of the RRVCHs remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). Therefore, the staff's concern described in RAI 4.3.2.1-5 is resolved.

Reactor Pressure Vessel Nozzles, Flange, and Studs. LRA Table 4.3-2 shows the 40-year design transient cycle counts along with the 60-year projected number of (actual) cycles for STP Units 1 and 2. Table 4.3-3 shows both the 40-year (design) and the 60-year (projected) fatigue usage factors for both units. The staff noted that the 40-year CUFs for the RV components such as the vessel flange, studs, and RPV nozzles, and the 60-year CUFs for these components, are all within the ASME Code allowable of 1.0, except for 60-year value for the stud hole inserts. Footnote 2 to LRA Table 4.3-3 states that the 40-year design basis number of events "should be sufficient for 60 years of operation." The staff also noted that the applicant stated that it will manage these components to limit the number of transients to below the 40-year design limits through its Metal Fatigue of Reactor Coolant Pressure Boundary Components AMP; however, the meaning of "should be sufficient" in Footnote 2 to LRA Table 4.3-3 was ambiguous. In RAI 4.3.2.1-6, the staff asked the applicant to demonstrate that the 40-year design basis transient cycles are, in fact, sufficient for 60 years.

By letter dated May 12, 2011, the applicant responded that the term "should be [sufficient]" refers to a potential that a unit would exceed a 40-year design basis number of cycles. The applicant stated that, when the 60-year projections of Table 4.3-3 are compared to the 40-year design basis quantities, the 40-year design basis numbers of events are bounding for 60 years. The applicant also stated that by using the Metal Fatigue of Reactor Coolant Pressure Boundary AMP, the applicant ensures that the actual transients remain below the projected number of events for 60 years; thus the CUFs for these RPV components during the period of extended operation would be maintained less than the allowable of 1.0. In the case of the stud hole inserts, LRA Table 4.3-3 shows that the projected 60-year CUF for the stud hole inserts is 1.3278, which exceeds the allowable of 1.0; the applicant stated that the Metal Fatigue of Reactor Coolant Pressure Boundary Components AMP will monitor the actual transient cycles to ensure that the CUF will not exceed the allowable of 1.0 for the stud hole inserts. When the CUF approaches 1.0, the applicant will take appropriate actions in accordance with the Metal Fatigue AMP. Based on the above evaluation, the staff's concern as described in RAI 4.3.2.1-6 is resolved.

In RAI 4.3.2.1-7, the staff asked the applicant to demonstrate that multiplying a factor of 1.5 to the 40-year CUF is appropriate, or at a minimum, conservative. By letter dated May 12, 2011, the applicant responded that this approach has been shown to be conservative through operating history, as shown in LRA Table 4.3-2. The applicant calculated the CUF in accordance with ASME Code Section III, paragraph NB-3222.4(e)(5).

The applicant stated that when the calculated 60-year CUF approaches 1.0, the CUF analysis will be managed through the Metal Fatigue of Reactor Coolant Pressure Boundary AMP, and the TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

The staff finds that the Metal Fatigue of Reactor Coolant Pressure Boundary AMP ensures that the number of transients actually experienced during the period of extended operation remain below the assumed number, or that appropriate corrective actions maintain the design and licensing basis by other means. The effects of fatigue will therefore be managed for the period of extended operation. Those TLAAs will be dispositioned in accordance with 10 CFR 54.21(c)(1)(iii). The staff also finds that the applicant has shown that the CUF is directly proportional to the transient cycle count, in accordance with ASME Code Section III, paragraph NB-3222.4(e)(5). Therefore, the staff's concern as described in RAI 4.3.2.1-7 is resolved.

The staff reviewed LRA Table 4.3-3 and noted that for the reactor studs, the 40-year CUF for Units 1 and 2 is 0.3372, and for the stud hole inserts, the value is 0.885. During its audit, the staff noted that Stud No. 30 of Unit 2 had rotated inadvertently during a de-tensioning process, causing it to partially engage inside the stud hole insert and causing damage to both Stud No. 30 and its stud hole insert. The applicant's design change package to address the issue conservatively estimated the damaged areas of the stud hole insert bearing surfaces to be 17 percent of the original area of contact. The applicant replaced Stud No. 30 and performed an evaluation on the stud hole insert, determining that the non-conforming condition of the stud insert should be dispositioned as "Use-As-Is."

The staff noted that the reduced load bearing surfaces of the partially rolled stud hole insert would increase the stress level applied to the stud and to the stud hole insert, which could affect assumptions used in the fatigue analyses. The staff also noted that the stud nut, washer, and associated collar were not damaged during this event, and that the stud was replaced. By letter dated September 22, 2011, the staff issued RAI 4.3-8, requesting that the applicant justify that the assumptions and results of the fatigue analyses of these components remain valid, when considering the operating experience related to the stud hole insert, and that cumulative fatigue damage will be managed for the period of extended operation.

In its response dated November 21, 2011, the applicant stated that the damage to the stud hole insert was along only about 17 percent of the length of the lug. The applicant clarified that the damage was radially inward from the location of the maximum usage factor (which would occur at the intersection of the lug and the vertical cylinder surface of the insert). In addition, the applicant explained that the current CUF calculation of 0.8852 is very conservative; the stress pairing that contributes the most to fatigue was analyzed for 13,177 events—when only 10 events were required—which adds about 0.4 to the CUF. Therefore, the applicant concluded that the reported CUF of 0.8852 is bounding, and the damage will not affect the number of analyzed design transients. The applicant also stated that the Metal Fatigue of Reactor Coolant Pressure Boundary Program will maintain this margin for the original analysis during the period of extended operation by ensuring that the specified quantity of 10 events is not exceeded.

Based on the applicant's response, the staff was not clear as to what "event" was analyzed for 13,177 cycles and what document (e.g., design specification, Code, or Standard) required only 10 of these events to be analyzed. It was also not clear which transient is being monitored by the Metal Fatigue of Reactor Coolant Pressure Boundary Program for the "specified 10 events." The staff reviewed LRA Table 4.3-2, and it was not clear which transient is being monitored. By letter dated January 31, 2012, the staff issued RAI 4.3-8a (followup) to request these clarifications.

In its response to RAI 4.3-8a (followup) dated February 16, 2012, the applicant stated that the primary side hydrostatic test transient (10 cycles) was paired with 13,177 of the 13,200 unit unloading at 5 percent of full power per minute transient in the design fatigue analysis for the stud hole insert. In addition, the applicant clarified that the transients used in the design fatigue analysis for the stud hole insert are specified in the RPV design specification, which was provided as part of the response. The staff's evaluation associated with the overall aging management of the damaged stud hole insert is documented in SER Section 3.0.3.2.2 for the Reactor Head Closure Studs Program.

With respect to metal fatigue, the staff noted that that applicant's response to RAI 4.3-8, dated November 21, 2011, stated that damage to the stud hole insert—along only about 17 percent of the length of the lug and radially inward from the location of the maximum usage factor (at the intersection of the lug and the vertical cylinder surface of the insert)—is such that the bending moment loading on the lugs at the maximum usage factor location is not as great as at the damaged location. Therefore, the increase in stress at the maximum usage factor location would be less than 17 percent. It was not clear to the staff how the applicant made these determinations. Therefore, by letter dated March 21, 2012, the staff issued RAI B2.1.3-2b requesting the applicant, in Part 6, to justify how it determined that the increase in the stress at the maximum usage factor location would be less than 17 percent and that the increase in stress at this location would not result in exceeding the Code design limit CUF of 1.0.

In its response to RAI B2.1.3-2b, Part 6, dated April 17, 2012, the applicant provided an explanation related to the effects of the damaged stud hole insert on metal fatigue. The applicant described the design and configuration of the stud hole insert, including an explanation of the damaged area and location of the calculated maximum CUF. The staff noted that the deformation of the stud hole insert occurred away from the location of the calculated maximum CUF.

The applicant stated that the bearing damage does not create higher peak stress intensities that would cause the CUF to increase as result of additional stress concentration, and the bending stress is less at the edge of the bearing deformation: since it is radially inward from the location of the maximum usage factor at the lug-ID wall juncture, the moment arm is reduced. In addition, the applicant stated that, according to the calculation for the stud hole insert, the fillet radii could not be modeled in the 3-D finite element analysis, and the results already include high stress concentration. The staff noted that the calculated peak stress values would be higher than the actual values due to difference between the modeling and the actual layout of the stud hole insert.

The applicant clarified that the largest contribution to the design CUF value of 0.8852 is due to the pairing of cold hydrostatic test and unit loading at 5 percent of full power per minute. The staff noted that the applicant used 13,177 cycles for this pairing when only 10 occurrences of cold hydrostatic test needed to be considered, as defined by the design specification. The applicant stated that using 10 cycles of the cold hydrostatic test would reduce the calculated CUF by 0.470. The applicant also provided an explanation of how the CUF value could be further refined consistent with the provisions defined by ASME Code Section III, paragraph NB-3222.4

The staff noted that ASME Code Section III, paragraph NB-3222.4(e), requires that the CUF not exceed 1.0. Based on the available refinement in the maximum CUF value, the staff finds it reasonable that there is margin in the calculated maximum CUF for the stud hole insert because of (a) the conservative methods used in the design transients to calculate the CUF, as described above, and (b) the applicant's use of primary plus secondary plus peak stresses based on a high stress concentration when compared to the actual layout of the stud hole insert.

The staff also noted that the applicant stated in LRA Section 4.3.2.1 that the effect of fatigue for the closure studs and stud hole inserts will be managed by the Metal Fatigue of Reactor Coolant Pressure Boundary Program. The program ensures that the number of transients actually experienced by the component during the period of extended operation remains below the assumed number of cycles in the analysis; otherwise, corrective actions will be taken.

The staff finds the applicant's response to RAI B2.1.3-2b, Part 6, acceptable because the ASME Code design limit CUF of 1.0 is not exceeded, as discussed above, and the applicant is managing the effects of fatigue with its Metal Fatigue of Reactor Coolant Pressure Boundary Program to ensure the validity of CUF analyses through the period of extended operation. The staff's concern identified in RAI B2.1.3-2b, Part 6, is resolved. The staff's evaluation of the applicant's responses to RAI B2.1.3-2b, Parts 1-5, is documented in SER Section 3.0.3.2.2.

The staff finds that—for the reactor pressure nozzles, flange, and studs—the Metal Fatigue of Reactor Coolant Pressure Boundary aging management program will adequately manage the effects of CUF by ensuring that the numbers of transients actually experienced during the period of extended operation remain below the 40-year design basis values. Otherwise, appropriate corrective actions to maintain the design and licensing basis by other acceptable means will be taken. The effects of fatigue will, therefore, be managed for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

<u>Unit 1 Reactor Vessel Bottom Mounted Instrument Nozzle Repairs</u>. In RAI 4.3.2.1-8, the staff asked the applicant to identify any flaws or indications that remain in service in the RPV components and discuss how these flaws or indications will be managed throughout the period of extended operation. By letter dated May 12, 2011, the applicant responded that after searching the UFSAR, TSs, the NRC SERs for the original operating licenses, subsequent NRC SEs, and STPNOC and NRC docketed licensing correspondence, the only flaws remaining in service in the RPV are the flaws in Unit 1 BMI nozzles 1 and 46. The staff's concern described in RAI 4.3.2.1-8 is resolved because the applicant has confirmed that the only flaws are the specific Unit 1 BMI nozzles. The issue of their acceptability for the period of extended operation is evaluated below.

LRA Section 4.3.2.1 states that the 48-year fatigue crack growth analysis, CUF analysis, and the corrosion analysis for the Unit 1 BMI nozzles and lower head repairs are valid for the period of extended operation. In RAI 4.3.2.1-4, the staff asked the applicant to demonstrate how these three analyses remain valid for the period of extended operation.

By letter dated May 12, 2011, the applicant responded that the fatigue crack growth analysis for the repaired Unit 1 BMI nozzles assumes the numbers of transient cycles equivalent to 48 years of operation by using 120 percent (48 year/40 year) of the design numbers of transients in UFSAR Table 3.9-8. Since this fatigue crack growth analysis covers an additional 48 years of operation from the repair date of 2003 (i.e., effective to 2051), the fatigue crack growth analysis is valid through the period of extended operation, which ends in 2047. The staff finds that the fatigue crack growth analysis for the repaired BMI nozzles remains valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

For the CUF analysis of the repaired Unit 1 BMI nozzles, the applicant stated that the analysis assumed transient cycles equivalent to 50 years of operation. The applicant stated that the validity of the CUF analysis of the repaired BMI penetrations extends from the repair date of the condition in 2003 to 2053, which is beyond the end of the period of extended operation in 2047. The staff finds that the CUF analysis for the Unit 1 repaired BMI nozzles remains valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

For the corrosion analysis of the repaired Unit 1 BMI nozzles, the applicant used a corrosion rate of 0.00153 in. per year to project the total metal corrosion in 50 years. The applicant doubled the rate to give the diametral corrosion rate of 0.00306 in. per year, or 0.153 in. in the 50 years from the repair in 2003, which extends the analysis to 2053 and through the end of the period of extended operation (2047). The applicant calculated that the base metal corrosion in the repaired BMI can increase the bore diameter from 1.562 in. to 1.95 in. (a diametral increase of 0.388 in.) and still meet the stress requirements of ASME Code Section III.

The applicant stated that the application of the corrosion rate through the period of extended operation is conservative because general corrosion will decrease after a period of time due to the lack of oxygen, tight geometry, and lack of RCS flow at the location. The applicant derived the corrosion rate using the methodology documented in Combustion Engineering report, CE NPSD-1198-P, Revision 0, which the staff has approved. In support of relief request RR-ENG-2-33, the applicant provided information concerning the effects of corrosion on the BMI half-nozzle repairs in letters dated July 3, 2003 (ADAMS Accession No. ML031920109) and July 17, 2003 (ADAMS Accession No. ML032020109). The NRC approved relief request RR-ENG-2-33 in a letter dated August 1, 2003 (ADAMS Accession No. ML032130454).

To confirm the applicant’s corrosion rate, the staff used information from Westinghouse topical report WCAP-15973-P, Revision 1, “Low-Alloy Steel Component Corrosion Analysis Supporting Small Diameter Alloy 600/690 Nozzle Repair/Replacement Program,” which the NRC approved on January 12, 2005 (ADAMS Accession No. ML050180528). The corrosion rate of 1.53 mils per year used by the applicant is the same as the corrosion rate specified in WCAP-15973-P. Therefore, the staff finds that the applicant’s corrosion rate to project the metal loss in the affected BMI nozzles is acceptable. The staff finds that the applicant’s corrosion analysis remains valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

The staff notes that the fatigue crack growth analysis showed that the repaired BMI nozzles in Unit 1 are acceptable for operation up to 48 years, and the CUF and corrosion analyses showed the repaired BMI nozzles are acceptable for 50 years. The 48-year duration is more limiting than the 50-year duration. Therefore, the staff concludes that the repaired BMI nozzles are acceptable for 48 years. As stated above, the applicant repaired the two BMI nozzles in Unit 1 in 2003. Extending 48 years from 2003, the repaired Unit 1 BMI nozzles are acceptable for operation up to the end of the period of extended operation in 2047. Based on the above evaluation, the staff’s concern as described in RAI 4.3.2.1-4 is resolved.

4.3.2.1.3 UFSAR Supplement

LRA Section A3.2.1.1 provides the UFSAR supplement summarizing its TLAA of the RV, nozzles, head, and studs. The staff reviewed LRA Section A3.2.1.1, consistent with the review procedures in SRP-LR Section 4.7.3.2, which state that the staff confirms that the UFSAR supplement includes a summary description of the evaluation of each TLAA. Based on its review of the UFSAR supplement, the staff finds that it meets the acceptance criteria in SRP-LR Section 4.7.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA for the RV, nozzles, head, and studs, as required by 10 CFR 54.21(d).

4.3.2.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the CUF analyses for the RRVCHs and the analyses for the repaired Unit 1 BMI nozzles (fatigue crack growth, CUF, and corrosion) remain valid for the period of extended operation. The staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions of RPV nozzles, flange, and studs (including the stud hole inserts) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation of the RV, nozzles, head, and studs, as required by 10 CFR 54.21(d).

4.3.2.2 Control Rod Drive Mechanism (CRDM) Pressure Housings and Core Exit Thermocouple Nozzle Assemblies (CETNAs)

4.3.2.2.1 Summary of Technical Information in the Application

LRA Section 4.3.2.2 describes the applicant's metal fatigue TLAA for Unit 1 and Unit 2 CRDM pressure housings, the CETNAs,. The applicant stated that these components were replaced with the RRVCHs. In addition, the CRDM pressure housings and CETNAs were designed to the Class 1 requirements of the ASME Code, Section III, 1989 edition (no addenda).

The applicant stated the Unit 1 and 2 replacement RV heads, including CRDMs and CETNAs, were analyzed for a 40-year design life at the time of replacement; therefore, they are valid for the period of extended operation. The applicant dispositioned the TLAA for the CRDMs and CETNAs in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid during the period of extended operation.

4.3.2.2.2 Staff Evaluation

The staff reviewed LRA Section 4.3.2.2 and the metal fatigue TLAA for the CRDMs and CETNAs to confirm, pursuant to 10 CFR 54.21(c)(1)(i), that the analysis remains valid during the period of extended operation.

The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with the review procedures in SRP-LR Section 4.3.3.1.1.1, which state that the operating transient experience and a list of the assumed transients used in the existing CUF calculations for the current operating term are reviewed to ensure that the number of assumed transients would not be exceeded during the period of extended operation.

LRA Section 4.3.2.1 states that the Unit 1 RPV head was replaced during the fall of 2009, and the Unit 2 RPV head was replaced during the spring of 2010. The staff noted that the CRDM pressure housings and CETNAs were designed to the Class 1 requirements of the ASME Code, Section III, 1989 edition (no addenda.) In addition, these components were designed and qualified for 40 years, which extends the design lives (2049 for Unit 1 and 2050 for Unit 2) beyond the period of extended operation. Since these components were designed to ASME Code Section III, they were required to have a CUF value less than 1.0 for the design life (i.e., 40 years) in order to be qualified for service. The staff reviewed LRA Table 4.3-3, which provides the CUF values for RV head components, and noted that the 40-year CUF values were less the Code design limit of 1.0. Since the fatigue analyses for these components determined a CUF less than the Code limit beyond the period of extended operation, the staff finds that these analyses will remain valid during the period of extended operation.

The staff finds that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses for the CRDM pressure housings and CETNAs remain valid for the period of extended operation. Additionally, the analyses meet the acceptance criteria in SRP-LR Section 4.3.2.1.1.1 because the design life of the RV head for Units 1 and 2 include the CRDM pressure housings and CETNAs, and the associated fatigue analyses extend beyond the period of extended operation.

4.3.2.2.3 UFSAR Supplement

LRA Section A3.2.1.2 provides the UFSAR supplement summarizing the metal fatigue TLAA for the CRDM pressure housings and CETNAs. The staff reviewed LRA Section A3.2.1.2, consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the reviewer confirms that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the metal fatigue TLAA for the CRDM pressure housings and CETNAs, as required by 10 CFR 54.21(d).

4.3.2.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the fatigue analyses for the CRDM pressure housings and CETNAs remain valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.2.3 Reactor Coolant Pump Pressure Boundary Components

4.3.2.3.1 Summary of Technical Information in the Application

LRA Section 4.3.2.3 describes the applicant’s metal fatigue TLAA for the Unit 1 and Unit 2 RCP pressure boundary components. The applicant stated that there are four Model 100 RCPs for each reactor that were designed to the Class 1 requirements of ASME Code Section III, 1971 edition, with addenda through summer 1973. Furthermore, this design code requires a fatigue analysis per NB-3222.4(e) or a fatigue waiver per NB-3222.4(d).

The fatigue analyses for the RCP pressure boundary components were performed with transients consistent with those assumed in UFSAR Table 3.9-8, with additional cooling water and seal injection transients. The LRA states that the analyses demonstrated code compliance for most RCP components by satisfying the six criteria for a fatigue waiver. The exceptions are those components for which the range of primary plus secondary stress intensity exceeds $3S_M$ for normal and upset conditions, which include the casing (CUF of 0.4), thermal barrier flange (CUF of 0.8287), cooling coils (CUF of 0.25), seal injection nozzle (CUF of 0.85), and thermal barrier cooling water nozzle (CUF of 0.4525). The applicant stated that Westinghouse equipment specifications include safety injection and thermal barrier cooling water transients that are specific to the RCP auxiliary nozzles, coiling coils, and the thermal barrier flange at the holes.

The applicant dispositioned the TLAA for the thermal barrier flange at the holes and the seal injection nozzles in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation. The applicant also dispositioned the TLAA for the RCP casing, thermal barrier cooling coils, and the thermal barrier water nozzles in accordance with 10 CFR 54.21(c)(1)(ii), that the analyses have been projected to the end of the period of extended operation. In addition, the applicant dispositioned the TLAA for the fatigue waivers of RCP pressure boundary components in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the RCP pressure-retaining components will be adequately managed by the Metal Fatigue of Reactor Coolant Pressure Boundary Program for the period of extended operation.

4.3.2.3.2 Staff Evaluation

The staff reviewed LRA Section 4.3.2.3 and the metal fatigue TLAAs for the RCP pressure boundary components to confirm, pursuant to 10 CFR 54.21(c)(1)(i), that the analysis remains valid during the period of extended operation. The staff also confirmed, pursuant to 10 CFR 54.21(c)(1)(ii), that the analyses have been projected to the end of the period of extended operation and, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue will be adequately managed by the Metal Fatigue of Reactor Coolant Pressure Boundary Program for the period of extended operation.

The staff reviewed the applicant's TLAAs for the thermal barrier flange at the holes and the seal injection nozzles and the corresponding disposition of 10 CFR 54.21(c)(1)(i), consistent with the review procedures in SRP-LR Section 4.3.3.1.1.1. These procedures state that the operating transient experience and a list of the assumed transients used in the existing CUF calculations for the current operating term are reviewed to ensure that the number of assumed transients would not be exceeded during the period of extended operation.

The staff also reviewed the applicant's TLAAs for the RCP casing, thermal barrier cooling coils, thermal barrier water nozzles, and the corresponding disposition of 10 CFR 54.21(c)(1)(ii), consistent with the review procedures in SRP-LR Section 4.3.3.1.1.2. These procedures state that the revised CUF calculations are reviewed to ensure that the CUF remains less than or equal to 1.0 at the end of the period of extended operation.

In addition, the staff reviewed the applicant's TLAA for the fatigue waivers of RCP pressure boundary components and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with the review procedures in SRP-LR Section 4.3.3.1.1.3. These procedures state that the reviewer should confirm the appropriateness of the applicant's program for monitoring and tracking the number of critical thermal and pressure transients for the selected RCS components.

The applicant stated that the fatigue and fatigue waiver analyses have been updated to incorporate redefinitions of loads and design basis events, operating changes, power uprate, and other modifications. The staff finds it appropriate that the applicant updated the fatigue and fatigue waiver analyses for the RCP pressure boundary components because these analyses currently account for the actual equipment configuration and actual stresses caused by the operating conditions for these components at the applicant's site.

The staff noted that the fatigue analyses for the thermal barrier flange at the holes and seal injection nozzles indicate that the only transient that is significant to fatigue is the step change in seal injection flow temperature (180 cycles). The applicant described, in LRA Section 4.3.2.3, that this transient will occur when the charging pump suction is switched from the volume control tank to the refueling water storage tank and back. In addition, the site does not operate in this manner, and the equipment failure that would cause the auto-swap inadvertently has never happened. The staff noted that the fatigue analyses for the thermal barrier flange at the holes and seal injection nozzles were performed with transients consistent with those assumed in UFSAR Table 3.9-8 (reproduced in LRA Table 4.3-2) and the additional transient described above. The staff reviewed LRA Table 4.3-2 and noted that there is margin between the UFSAR design cycles and the 60-year projected cycles. The staff finds it reasonable that the 40-year design CUF for the thermal barrier flange at the holes (0.8287) and seal injection nozzles (0.85) will not be exceeded during the period of extended operation because there is margin between the 60-year projected cycles and the UFSAR design cycles, and the most significant transient that contributes to these CUFs has not occurred and is not expected to occur during normal operation (consistent with the way the applicant operates its units).

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses for the thermal barrier flange at the holes and seal injection nozzles remain valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.3.3.1.1.1 because the transients used in the fatigue analyses to calculate the CUF will not be exceeded during the period of extended operation, and the most significant contributor to CUF values is not expected to occur at the site.

The staff noted that for the CUF values of the RCP casing (0.4), thermal barrier cooling coils (0.25), and thermal barrier water nozzles (0.4525), the applicant extrapolated to 60 years by multiplying the CUFs by a factor of 1.5, which still demonstrated that the design Code limit of 1.0 was not exceeded, as described in LRA Section 4.3.2.3. The staff finds the use of this 1.5 factor reasonable to be applied to the 40-year design CUF values because the resulting estimated 60-year CUF values provides a gauge of how much margin is available before the design limit of 1.0 is reached. For the RCP casing, thermal barrier cooling coils, and thermal barrier water nozzles, the staff noted that there is 32 percent margin or more between the 60-year projected CUF values and the Code design limit of 1.0.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the analyses for the RCP casing, thermal barrier cooling coils, and thermal barrier water nozzles have been projected to the end of the period of extended operation. Additionally, it meets the acceptance criteria of SRP-LR Section 4.3.2.1.1.2 because the applicant has demonstrated that the 60-year projected CUF values will be less than the ASME Code, Section III, design limit of 1.0 through the period of extended operation with significant margin.

The staff noted that the components of the RCP that form part of the RCPB are subject to an ASME Code fatigue analysis per NB-3222.4(e) or a fatigue waiver per NB-3222.4(d). In addition, these analyses demonstrated ASME Code compliance for most RCP components by satisfying the six criteria for a fatigue waiver, with the exception of those components described above. The applicant dispositioned these fatigue waiver TLAAs in accordance with 10 CFR 54.21(c)(1)(iii), that the Metal Fatigue of Reactor Coolant Pressure Boundary Program will manage effects of fatigue for the period of extended operation. However, it is not clear how the applicant’s program will ensure that the fatigue waiver for RCP pressure-retaining components will remain valid for the period of extended operation. By letter dated September 22, 2011, the staff issued RAI 4.3-15, requesting that the applicant describe how the Metal Fatigue of Reactor Coolant Pressure Boundary Program will manage the effects of cumulative fatigue damage through the period of extended operation for those RCP components and associated TLAAs that satisfied the six criteria for a fatigue waiver per NB-3222.4(d).

In its response dated November 21, 2011, the applicant stated that fatigue waiver requirements are dependent on the numbers of anticipated transients over the life of the plant. In addition, the fatigue waiver for the RCPs was performed with transients consistent with those identified in UFSAR Table 3.9-8. The staff noted that so long as the number of transients that occur for a unit remain bounded by the 40-year numbers of cycles assumed in the fatigue waiver, the waiver will remain valid. The staff noted that the applicant’s Metal Fatigue of Reactor Coolant

Pressure Boundary Program ensures that the numbers of transients actually experienced during the period of extended operation remain below the assumed number in the fatigue waiver or that corrective actions will be taken. The staff's evaluation of the Metal Fatigue of Reactor Coolant Pressure Boundary Program is documented in SER Section 3.0.3.2.28.

The staff finds the applicant's response acceptable because the applicant confirmed that the transients assumed in the fatigue waiver are consistent with those in the UFSAR and the Metal Fatigue of Reactor Coolant Pressure Boundary Program. This will ensure that if the assumptions made in the fatigue waiver are approached, corrective actions will be taken. The staff's concern described in RAI 4.3-15 is resolved.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the RCP pressure boundary components with fatigue waivers will be adequately managed for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.3.2.1.1.3 because the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program monitors and tracks the number of design basis transients that will occur through the period of extended operation. Additionally, this program includes action limits and corrective actions that will ensure that the assumptions made in the fatigue waiver will not be exceeded during the period of extended operation.

4.3.2.3.3 UFSAR Supplement

LRA Section A3.2.1.3 provides the UFSAR supplement summarizing the metal fatigue TLAA for the RCP pressure boundary components. The staff reviewed LRA Section A3.2.1.3 consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the reviewer confirms that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the metal fatigue TLAA for the RCP pressure boundary components, as required by 10 CFR 54.21(d).

4.3.2.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses for the thermal barrier flange at the holes and the seal injection nozzles remain valid for the period of extended operation. The staff also concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(ii), that the analyses for the RCP casing, thermal barrier cooling coils, and thermal barrier water nozzles have been projected to the end of the period of extended operation. In addition, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the RCP pressure boundary components with fatigue waivers will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.2.4 Pressurizer and Pressurizer Nozzles

4.3.2.4.1 Summary of Technical Information in the Application

LRA Section 4.3.2.4 describes the applicant's metal fatigue TLAA for the pressurizer and pressurizer nozzles. LRA Section 4.3.2.4 states that the Westinghouse Series 100 pressurizers are vertical cylindrical vessels with hemispherical top and bottom heads, constructed of carbon steel, with austenitic stainless steel cladding on all surfaces exposed to the reactor coolant. The pressurizers and their integral support skirts are ASME Code Class 1, designed to ASME Code Section III, 1974 edition. As such, pressure-retaining and support components of the pressurizer are subject to an ASME Code Section III fatigue usage factor analysis.

The LRA states that the applicant has identified new design basis events that were not included in the original fatigue usage factor analyses. The applicant has re-evaluated the fatigue usage factor analyses considering the new parameters and transient cycles. The applicant found that the impact of 10 cold over-pressurization mitigation system activation events on the fatigue usage factor of the pressurizer is negligible.

Two components, the safety and relief nozzles and the manway, were previously exempt from a fatigue usage factor analysis by a waiver under ASME Code Section III, NB-3222.4(d). However, with an additional 6,000 pressure fluctuations (10 events with 600 pressure cycles per event), these two components are no longer exempt from the fatigue analysis requirement. The applicant has included the fatigue usage factors in the stress analysis results for these components, as shown in LRA Table 4.3-4. The applicant stated that the TLAA for the fatigue usage factor analyses of the safety and relief nozzles and the seismic support lugs are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii); the TLAAs for the fatigue usage factor analyses of the manway and the remaining items identified in LRA Table 4.3-4 are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

In addition, the applicant evaluated the effects of pressurizer insurge-outsurge transient cycles based on the Westinghouse report, WCAP-14950, and plant operations from the last seven heatups and seven cooldowns for STP, Units 1 and 2, combined. These heatups and cooldowns are assumed to represent all past and future operations in terms of pressurizer insurge-outsurge and surge line stratification activity. All components were qualified using the 40-year CLB cycles and incorporated into the Metal Fatigue of Reactor Coolant Pressure Boundary Program.

The applicant installed preemptive structural weld overlays (SWOLs) on pressurizer spray, relief, safety, and surge nozzles in both units in accordance with NRC-approved relief request RR-ENG-2-43. This modification is to mitigate the Alloy 82/182 dissimilar metal welds at the subject pressurizer nozzles, which are susceptible to PWSCC.

As part of the weld overlay design, the applicant performed crack growth analyses using the transients listed in UFSAR Table 3.9-8, spread evenly over a 40-year and a 60-year plant life. These analyses determine the amount of time necessary for a crack to propagate from 3/4 wall thickness to the interface between the SWOL and the pipe. This acceptance criterion is to confirm that an unidentified crack will not propagate to the SWOL interface during a 10-year ISI interval. If the crack is projected to propagate into the SWOL, then an inspection interval is to be established to ensure that the crack will not propagate into the SWOL prior to the next inspection. Since the crack is not qualified for the life of the plant, but only the inspection interval, the fatigue crack growth analysis is not a TLAA in accordance with 10 CFR 54.3(a), Criterion 3 (i.e., subparagraph 10 CFR 54.3(a)(3)).

The applicant performed fatigue usage factor evaluations for the limiting locations outside the SWOL. In the region within the SWOL, the stresses due to pressure and piping reaction loads are lower due to the increase in the pipe wall thickness as a result of the structural weld overlay. Therefore, these stress evaluations are not TLAAs in accordance with 10 CFR 54.3(a), Criterion 2.

4.3.2.4.2 Staff Evaluation

The staff reviewed LRA Section 4.3.2.4 and the metal fatigue TLAA for the pressurizer and pressurizer nozzles to confirm that the fatigue usage factor and crack growth analyses for the pressurizer and associated nozzles remain valid for the period of extended of operation, are projected to the end of the period of extended operation, or will be adequately managed for the period of extended operation, in accordance with 10 CFR 54.21(c)(i), (ii), or (iii) respectively. The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with the review procedures in SRP-LR Sections 4.3.2.1 and 4.7.3, which state that the review of the TLAA provides assurance that the aging effect is properly addressed through the period of extended operation.

LRA Section 4.3.2.4 discusses plant modifications, redefined loads, and newly identified design basis events. In RAI 4.3.2.4-1, the staff asked the applicant to describe in detail how the plant modifications affect the loads on the pressurizer and associated components (e.g., closures, nozzles, heaters, and support skirts) and to discuss the redefined loads and newly-identified design basis events.

By letter dated May 12, 2011, the applicant responded that the pressurizer weld overlay plant modifications, and the associated effects (i.e., redefined loads), have been considered in the design analyses. Other plant modifications—such as T_{hot} reduction, replacement steam generators, and reactor thermal power uprate—did not affect the loads on the pressurizer and associated components.

The applicant stated further that the newly-identified design basis events are the cold overpressure mitigation system (COMS) actuation and the pressurizer insurge-outsurge events. The COMS, implemented to satisfy the TS LCO 3.4.9.3 requirement for LTOP, was not initially incorporated into the fatigue usage factor analyses. Later, the applicant incorporated the 6,000 pressure cycles, as defined by the NSSS vendor, into the ASME Code design specification. Based on the above evaluation, the staff's concern described in RAI 4.3.2.4-1 is resolved.

LRA Section 4.3.2.4, page 4.3-18, states that "[t]he stress reports evaluated the effect on the pressurizer of 10 cold over-pressurization mitigation system activation events. The contribution of these thermal effects to the fatigue usage can be neglected." In RAI 4.3.2.4-3, the staff asked the applicant to explain why the contribution of these thermal effects to the fatigue usage factor can be neglected.

By letter dated May 12, 2011, the applicant responded that it had evaluated the effects of 10 COMS activation events on the pressurizers and found that many existing transient loadings that have already been included in the design basis of the pressurizer are much more severe than the RCS cold over-pressurization event. The addition of the less-severe COMS transients in the design basis of the pressurizer had a minimal effect on the component ASME Code analysis.

The applicant stated further that COMS actuation is a pressure transient. The thermally induced stresses associated with the COMS transient are small and the number of cycles of thermal events is low (10). Therefore, the contribution of these thermal effects to the fatigue usage factor can be neglected.

The staff finds it acceptable that the applicant has considered the redefined loads and newly identified design basis events in the fatigue usage factor and fatigue crack growth calculations of the pressurizer. The staff also finds it acceptable that the applicant has analyzed the impact of the COMS pressure and that the impact is minimal to the pressurizer. Based on the above evaluation, the staff's concern described in RAI 4.3.2.4-3 is resolved.

<u>Crack Growth Analysis of Overlaid Pressurizer Nozzles</u>. LRA Section 4.3.2.4 states that "[t]he fatigue crack growth analysis for pressurizer spray, relief, safety, and surge nozzle preemptive overlays is not a TLAA because the crack is not qualified for the life of the plant, but only the inspection interval." In RAI 4.3.2.4-4, the staff asked the applicant to confirm that every overlaid Alloy 82/182 weld in pressurizer spray, relief, safety, and surge nozzles will be inspected every 10 years and that the transient cycles will be monitored to confirm that the fatigue crack growth analysis bounds the actual transient cycles.

By letter dated May 12, 2011, the applicant responded that the overlaid Alloy 82/182 welds in pressurizer spray, relief, safety, and surge nozzles will be inspected every 10 years using a qualified performance demonstration initiative (PDI) ultrasonic technique in accordance with the ISI Program and MRP-139/ASME Code Case N-770-1 requirements. The applicant inspected the subject welds in spring 2010 for Unit 2 (2RE14) and fall 2009 for Unit 1 (1RE15), and no flaws were identified. The third ISI interval, which is scheduled to end in 2020, will adopt ASME Code Case N-770-1, "Alternative Examination Requirements and Acceptance Standards for Class 1 PWR Piping and Vessel Nozzle Butt Welds Fabricated with UNS N06082 or UNS W86182 Weld Filler Material With or Without Application of Listed Mitigation Activities Section XI, Division 1."

The applicant used 40 years of transient cycles in the fatigue crack growth calculation as part of the weld overlay design. The applicant stated that the fatigue crack growth analyses were not identified as a TLAA; thus, they did not require a disposition. However, the fatigue crack growth analyses, which support the weld overlay work, were performed with the same number of transients as the design fatigue analyses for the pipe. These transients will be monitored by the Metal Fatigue of Reactor Coolant Pressure Boundary AMP.

The staff notes that ASME Code Case N-770-1 has been incorporated by reference with conditions in the final rule for 10 CFR 50.55a, which was published in the *Federal Register* on June 21, 2011 (76 FR 36232). All licensees and applicants need to follow ASME Code Case N-770-1, as conditioned in 10 CFR 50.55a, in the inspection of Alloy 82/182 welds. The staff no longer accepts guidance in MRP-139 for the inspection of Alloy 82/182 welds. The staff notes that the applicant needs to follow the inspection requirements in the NRC-approved relief request for overlaid pressurizer nozzles first. In general, the staff authorizes the weld overlay relief request for only one 10-year ISI interval. After the relief request expires at the end of 10-year ISI interval, the applicant may follow the inspection requirements of Code Case N-770-1 with conditions in 10 CFR 50.55a or it may resubmit the weld overlay relief request for the subsequent 10-year ISI interval and follow the requirements in the re-approved relief request. The staff finds it is acceptable that the fatigue crack growth analyses for weld overlays are not a

TLAA because the overlaid Alloy 82/182 dissimilar metal welds will be inspected once every 10 years. The staff finds it acceptable that the applicant will monitor the transient cycles used in the fatigue crack growth analysis for the overlaid pressurizer nozzles via the Metal Fatigue of Reactor Coolant Pressure Boundary AMP. Based on the above evaluation, the staff's concern as described in RAI 4.3.2.4-4 is resolved.

Fatigue Usage Factor Analyses for Pressurizer Components with CUF Less Than 0.4. LRA Section 4.3.2.4, page 4.3-19, states that, as shown in LRA Table 4.3-4, the fatigue usage factor analyses of the pressurizer safety and relief nozzles and the seismic support lugs demonstrate the 40-year CUFs to be less than 0.4. When multiplied by 1.5 (60/40) to account for the 60-year period of extended operation, the projected CUFs do not exceed 0.6, providing a large margin to the ASME Code acceptance criterion of 1.0. The staff finds that the CUFs for safety and relief nozzles and the seismic support lugs have been satisfactorily projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

Fatigue Usage Factor Analyses for Pressurizer Components with CUF Greater Than 0.4. LRA Table 4.3-4 shows that several pressurizer components (other than the safety and relief nozzles and seismic support lugs) will have their CUF greater than the allowable of 1.0 at the end of 60 years, using a simple multiplier of 1.5 on the 40 year CUF values. The Metal Fatigue of Reactor Coolant Pressure Boundary AMP will ensure that the numbers of transients actually experienced during the period of extended operation remain below the assumed number in the CUF calculations. When the CUF approaches the allowable limit of 1.0, the applicant will take appropriate corrective actions to maintain the CUF to less than 1.0 by acceptable means.

In RAI 4.3.2.4-6, the staff asked the applicant to describe exactly how the Metal Fatigue AMP will monitor the transient cycles and track the CUFs of components. The staff also asked the applicant to describe in detail the corrective actions and acceptable means if the usage factor exceeds the allowable.

By letter dated May 12, 2011, in response to RAI 4.3.2.4-2 (which also addresses RAI 4.3.2.4-6), the applicant stated that the Metal Fatigue of Reactor Coolant Pressure Boundary AMP monitors the number of actual plant transients to ensure that they do not exceed the number of transients used in the design fatigue analyses for the pressurizer components. The applicant reviewed the pressurizer design basis to ensure that it was within the scope of the AMP or that the AMP was enhanced to consider the additional transients included in the pressurizer design basis. Therefore, the monitoring program also ensures that the number of transient cycles experienced by the plant will be within the cycles used in the pressurizer design basis during the period of extended operation.

The applicant stated further that the current procedure for the Metal Fatigue of Reactor Coolant Pressure Boundary AMP requires the control room to complete daily screening data sheets. If a transient occurs, a transient specific datasheet is completed to record the plant's conditions during the event. This process will be changed for the period of extended operation to run computer software to assess plant instrumentation data recorded by the plant process computer and identify the transients that have occurred. At least once per fuel cycle, the information will be validated to ensure an accurate transient count and the actual transient severity remains within the design basis. The cycle counts are then compared to the action limits, and corrective action is initiated when actual transient cycles exceed 80 percent of its design limit. Corrective actions are discussed in more detail in LRA Section B3.1 and in the applicant's response to RAI 4.3.2.11-3, and are evaluated in SER Section 4.3.2.11. The term "other acceptable means" refers to actions other than counting cycles, which are meant to address fatigue at the plant.

When other acceptable corrective action is required, a 10 CFR 50.59 review is performed in order to determine if the methods and results are in line with the CLB of the plant or if regulatory review is needed.

The applicant explained that the appropriate corrective actions are described in LRA Section B3.1 and LRA Table A4-1, Commitment No. 30. As part of response to RAI 4.3.2.11-3, the applicant revised the Corrective Actions (Element 7) in the Metal Fatigue AMP in LRA Section B3.1, as documented in the applicant's letter dated May 12, 2011. The enhanced corrective action description includes fatigue reanalysis, repair, replacement, or augmented inspections. The staff finds that the revised LRA Section B3.1 provides additional detailed monitoring on the fatigue usage factor calculation and associated corrective actions. The staff finds it is acceptable that the applicant has clarified and enhanced the Metal Fatigue AMP to monitor the transients in the CUF calculations for pressurizer components with 40-year CUF values greater than 0.4 in LRA Table 4.3-4. Based on the above evaluation, the staff's concern described in RAI 4.3.2.4-6 is resolved.

The staff finds that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of fatigue in these pressurizer subcomponents—as shown in LRA Table 4.3-4—will be adequately managed for the period of extended operation.

4.3.2.4.3 UFSAR Supplement

LRA Section A3.2.1.4 provides the UFSAR supplement summarizing description of its TLAA of the pressurizer and pressurizer nozzles. The staff reviewed LRA Section A3.2.1.4, consistent with the review procedures in SRP-LR Section 4.7.3.2, which state that the staff confirms that the UFSAR supplement includes a summary description of the evaluation of each TLAA. Based on its review, the staff finds that the UFSAR supplement meets the acceptance criteria in SRP-LR Section 4.7.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA of the pressurizer and pressurizer nozzles, as required by 10 CFR 54.21(d).

4.3.2.4.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(ii), that the cumulative fatigue analyses of the pressurizer safety and relief nozzles and seismic support lugs have been projected to the end of the period of extended operation. The staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the cumulative fatigue analyses for the pressurizer components that have 40-year CUF values greater than 0.4, as shown in LRA Table 4.3-4, will be adequately managed for the period of extended operation. The staff concludes that the fatigue crack growth analysis for the overlaid alloy dissimilar metal welds at pressurizer nozzles is not a TLAA because the overlaid welds will be inspected periodically depending on the allowable time calculated by the flaw growth analysis, the required inspection interval in accordance with the NRC-approved weld overlay relief request, or ASME Code Case N-770-1 with conditions in 10 CFR 50.55a. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation of the pressurizer and pressurizer nozzles, as required by 10 CFR 54.21(d).

4.3.2.5 Steam Generator ASME Code Class 1, Class 2 Secondary Side, and Feedwater Nozzle Fatigue Analyses

4.3.2.5.1 Summary of Technical Information in the Application

LRA Section 4.3.2.5 describes the applicant's metal fatigue TLAA for the STP, Units 1 and 2, replacement steam generators (RSGs). The applicant stated that the STP, Units 1 and 2, steam generators were replaced (in 2000 and 2002, respectively) with Westinghouse Model Delta 94 steam generators and are designed for 40 years of operation (for operation until 2040 and 2042, respectively), based on design transients. In addition, the RSGs are designed and fabricated to the requirements of ASME Code Section III, 1998 edition with no addenda. The primary side of each RSG is ASME Code Class 1, and the secondary side of each RSG is ASME Code Class 2; however, the entire pressure boundary of the component is constructed in accordance with ASME Code Section III, Class 1 requirements. The applicant stated that fatigue usage factors in the steam generator components do not depend on flow-induced vibration or other effects that are time-dependent at steady state conditions but depend only on effects of operational and upset transient events specified in the design specification.

The applicant dispositioned the TLAAs for the Unit 1 and 2 RSGs in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the RSG components will be adequately managed by the Metal Fatigue of Reactor Coolant Pressure Boundary Program for the period of extended operation.

4.3.2.5.2 Staff Evaluation

The staff reviewed LRA Section 4.3.2.5 and the TLAAs for the RSGs to confirm, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue will be adequately managed by the Metal Fatigue of Reactor Coolant Pressure Boundary Program for the period of extended operation.

The staff reviewed the applicant's disposition of the TLAA for the RSGs consistent with the review procedures in SRP-LR Section 4.3.3.1.1.3. These procedures state that the reviewer should confirm the appropriateness of the applicant's program for monitoring and tracking the number of critical thermal and pressure transients for the selected RCS components.

LRA Table 4.3-5 provides the 40-year CUF values for the RSG components, which are all less than the ASME Code design limit of 1.0, except for the primary manway studs, which have a 40-year CUF value of 7.13. In LRA Section 4.3.2.5, the applicant stated that the primary manway studs have a fatigue usage factor that exceeds the allowable of 1.0, but that they are qualified for 40 years by fatigue testing. The staff noted that the TLAA for RSGs, which includes the primary manway studs, was dispositioned in accordance with 10 CFR 54.21(c)(1)(iii). The applicant did not describe the details of the fatigue testing that was performed to qualify the primary manway studs for the Unit 1 and 2 RSGs; therefore, it was not clear how the applicant's program will manage fatigue of the primary manway studs. By letter dated September 22, 2011, the staff issued RAI 4.3-16, requesting that the applicant describe how the primary manway studs for the Unit 1 and 2 RSGs were qualified for 40-years by fatigue testing and to identify the sections of the applicable design codes that were used for the fatigue testing. In addition, the staff requested that the applicant justify how the Metal Fatigue of Reactor Coolant Pressure Boundary Program will manage cumulative fatigue damage of the primary manway studs for the Unit 1 and 2 RSGs.

In its response dated November 21, 2011, the applicant stated that the bolt fatigue testing was performed on bolts that represent the same thread size and material as the primary manway studs, and the number of fatigue test cycles was calculated to envelope the steam generator design transients based on a 40-year life. In addition, the fatigue tests were performed in accordance with ASME Code Section III, Appendix II, Article II-1500, as allowed per ASME Code Section III, paragraph NB-3222.4(a); therefore, the primary manway studs were qualified for fatigue by testing. In addition, the applicant stated that the fatigue test data envelops the number of cycles and the severity of the transients required by the design specification. The staff noted that the applicant's program ensures that the number and severity of transients actually experienced by the plant during the period of extended operation remain below the assumptions in the design specification or that corrective actions will be taken. The staff's evaluation of the Metal Fatigue of Reactor Coolant Pressure Boundary Program is documented in SER Section 3.0.3.2.28.

The staff finds the applicant's response acceptable because the primary manway studs were fatigue tested, in accordance with ASME Code Section III, Subsection NB and Appendix II, which envelope the steam generator design transients specified in the design specification. Additionally, the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program ensures that the number and severity of transients actually experienced does not exceed the assumptions made to qualify these primary manway studs for fatigue. The staff's concerns described in RAI 4.3-16 are resolved.

The applicant stated, in LRA Section 4.3.2.5, that Westinghouse evaluated the thermal-hydraulic performance and structural integrity of the replacement Model Delta 94 steam generators. This Westinghouse evaluation concludes there is no need to revise any data point on the design transient curves as a result of the 1.4 percent uprating; therefore, the original design transient curves remain applicable. The structural evaluation performed by Westinghouse focused on critical steam generator components that were determined by the stress ratios and fatigue usage as reported in the analyses of record. The applicant stated that by demonstrating that these most highly stressed components remain qualified for operation at the uprated power conditions, it may be concluded that these steam generator components remain structurally qualified. In addition, since the steam generator primary stresses remain the same while the secondary pressures are reduced as a result of uprating, all other steam generator components also remain structurally qualified. In the staff's SE documenting the approval of a 1.4 percent increase in reactor core thermal power levels for Units 1 and 2 (from 3,800 megawatts thermal (MWt) to 3,853 MWt), dated April 12, 2002 (ADAMS Accession No.ML021130083), the staff determined that the applicant's structural evaluation of the steam generator components is acceptable and that the original design parameters bound the power uprated conditions. The staff finds it appropriate that the applicant has considered the 1.4 percent uprated conditions and its effect on the fatigue analyses for the RSG components.

The applicant stated in LRA Section 4.3.2.5 that, as part of its RSG program, a new upset transient, COMS, was added to the original design basis for the RCS. This transient, which potentially occurs during startup or shutdown conditions at low temperatures, has been added to the UFSAR and was assumed to occur 10 times during the 40-year design life. The staff reviewed LRA Table 4.3-2 and confirmed that this transient is listed and tracked by the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program. The staff finds it appropriate that the applicant included this new upset transient as part of its UFSAR and Metal Fatigue of Reactor Coolant Pressure Boundary Program because it is consistent with the recommendations of GALL Report AMP X.M1 to monitor all plant design transients that cause cyclic strains which are significant contributors to the fatigue usage factor. The staff noted that as long as the number of transients that occur per unit remains bounded by the 40-year numbers of cycles assumed by the analysis, the design basis fatigue evaluation remains valid. The staff noted that the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program ensures that the numbers of transients actually experienced during the period of extended operation remain below the assumed number or that corrective actions will be taken. The staff's evaluation of the Metal Fatigue of Reactor Coolant Pressure Boundary Program is documented in SER Section 3.0.3.2.28.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the RSG components will be adequately managed for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.3.2.1.1.3 because the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program monitors and tracks the number design basis transients that will occur through the period of extended operation, and it includes action limits and corrective actions that will ensure the Code design limit of 1.0, or assumptions made to fatigue qualify the primary manway studs, will not be exceeded during the period of extended operation. Additionally, the use of the applicant's program is consistent with the recommendations of GALL Report AMP X.M1.

4.3.2.5.3 UFSAR Supplement

LRA Section A3.2.1.5 provides the UFSAR supplement summarizing the metal fatigue TLAA for the RSG components. The staff reviewed LRA Section A3.2.1.5 consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the reviewer confirms that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the metal fatigue TLAA for the RSG components, as required by 10 CFR 54.21(d).

4.3.2.5.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the RSG components will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.2.6 ASME Code Class 1 Valves

4.3.2.6.1 Summary of Technical Information in the Application

LRA Section 4.3.2.6 describes the applicant's metal fatigue TLAA for the ASME Code Section III, Class 1, valves. The applicant stated that its ASME Code Class 1 valves are designed to ASME Code Section III, Subsection NB, 1974 edition with summer 1975 addenda (pressurizer safety and control valves) or the 1974 edition with winter 1975 addendum (motor-operated, manual valves 3 in. and larger and all valves 2 in. and smaller). In addition, ASME Code Section III requires a fatigue analysis only for Class 1 valves with an inlet piping connection greater than 4-inch nominal pipe size.

The applicant dispositioned the TLAAs for the following ASME Code Class 1 valves in accordance with 10 CFR 54.21(c)(1)(ii), that the analyses have been projected to the end of the period of extended operation:

- 6-in. pressurizer safety relief valves
- 6-in. hi-head safety injection pump discharge check valves
- 8-in. hi-head safety injection pump discharge check valves
- 8-in. lo-head safety injection to hot leg check valves
- 12-in. safety injection to cold leg injection check valves
- 12-in. safety injection accumulator outlet valves
- 2-in. CVCS auxiliary spray check valves
- 2-in. RCP seal injection first and second check valves

The applicant also dispositioned the TLAA for the 12-inch RHR pump suction isolation valves in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of fatigue will be adequately managed by the Metal Fatigue of Reactor Coolant Pressure Boundary Program for the period of extended operation.

4.3.2.6.2 Staff Evaluation

The staff reviewed LRA Section 4.3.2.5 and the metal fatigue TLAAs for ASME Code Class 1 valves to confirm, pursuant to 10 CFR 54.21(c)(1)(ii), that the analyses have been projected to the end of the period of extended operation. The staff also confirmed, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue will be adequately managed by the Metal Fatigue of Reactor Coolant Pressure Boundary Program for the period of extended operation.

The staff reviewed the applicant’s TLAAs for the ASME Code Class 1 valves, described above, and the corresponding disposition of 10 CFR 54.21(c)(1)(ii), consistent with the review procedures in SRP-LR Section 4.3.3.1.1.2. These procedures state that the revised CUF calculations are reviewed to ensure that the CUF remains less than or equal to one at the end of the period of extended operation.

The staff also reviewed the applicant’s TLAA for the 12-in. RHR pump suction isolation valves and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with the review procedures in SRP-LR Section 4.3.3.1.1.3. These procedures state that the reviewer should confirm the appropriateness of the applicant’s program for monitoring and tracking the number of critical thermal and pressure transients for the selected RCS components.

For those TLAAs for Class 1 valves, in which the applicant dispositioned in accordance with 10 CFR 54.21(c)(1)(ii), the staff reviewed LRA Table 4.3-6 and noted the following:

Table 4.3-1. Class 1 Valves dispositioned in accordance with 10 CFR 54.21(c)(1)(ii)

Valve Description	40-year CUF	60-year CUF
6" pressurizer safety relief valves	0.0276	0.0414
6" hi-head safety injection pump discharge check valves	0.15	0.225
8" hi-head safety injection pump discharge check valves	0.14	0.21
8" lo-head safety injection to hot leg check valves	0.14	0.21

Valve Description	40-year CUF	60-year CUF
12" safety injection to cold leg injection check valves and safety injection accumulator outlet valves	0.05	0.075
2" CVCS auxiliary spray check valves	0.2063	0.3095
2" RCP seal injection first check valves and RCP seal injection second check valves	0.2186	0.3279

During its review of LRA Section 4.3.2.6 and LRA Table 4.3-6, the staff noted that the applicant did not provide a disposition, in accordance with 10 CFR 54.21(c)(1), of the fatigue TLAAs for the "8-inch Lo-Head Safety Injection Train A/B/C To Loop 1(2)A/B/C Cold Leg Check Valve" or the "3-inch [by] 6-inch Pressurizer Power Operated Relief Valve (PORV)." By letter dated September 22, 2011, the staff issued RAI 4.3-22, requesting that the applicant provide and justify the dispositions for the fatigue TLAA of these two Class 1 valves in accordance with 10 CFR 54.21(c)(1).

In its response dated November 21, 2011, the applicant stated that LRA Section 4.3.2.6 and Appendix A3.2.1.6 will be revised to note that the lo-head safety injection cold leg check valve and PORV are dispositioned in accordance with 10 CFR 54.21 (c)(1)(ii). The staff confirmed that the applicant dispositioned these two valves in accordance with 10 CFR 54.21(c)(1)(ii) in LRA Section 4.3.2.6 and Appendix A3.2.1.6.

The staff finds the applicant's response acceptable because the applicant revised its LRA to provide a disposition the fatigue TLAAs for the "8-inch Lo-Head Safety Injection Train A/B/C To Loop 1(2)A/B/C Cold Leg Check Valve" and the "3-inch [by] 6-inch Pressurizer Power Operated Relief Valve" in accordance with 10 CFR 54.21(c)(1). The staff's review of the applicant's disposition is documented below, and the concern described in RAI 4.3-22 is resolved. Based on the applicant's response, the following information for these two valves was noted from LRA Section 4.3.2.6:

Table 4.3-2. Additional Class 1 Valves dispositioned in accordance with 10 CFR 54.21(c)(1)(ii)

Valve Description	40-year CUF	60-year CUF
8" Lo Head Safety Injection Train A/B/C To Loop 1(2)A/B/C Cold Leg Check Valve	0.14	0.21
3"x6" Pressurizer Power Operated Relief Valve	0.16	0.24

The applicant stated that the 60 year CUF values were calculated by multiplying the 40-year CUF value by a factor of 1.5 (60/40). The staff noted that the 60-year CUF values for these ASME Code Class 1 valves remain below the ASME Code design limit of 1.0. The staff finds the use of this 1.5 factor reasonable for the 40-year design CUF values because the resulting estimated 60-year CUF values provides a gauge of how much margin is available before the design limit of 1.0 is reached. For the ASME Code Class 1 valves listed in the two tables above, the staff noted that there is 65 percent margin or more between the 60-year projected CUF values and the ASME Code design limit of 1.0.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the analyses for the ASME Code Class 1 valves, described above, have been projected to the end of the period of extended operation. Additionally, it meets the acceptance criteria of SRP-LR Section 4.3.2.1.1.2 because the applicant has demonstrated that the 60-year projected

CUF values will be less than the ASME Code, Section III, design limit of 1.0 through the period of extended operation with significant margin.

The staff reviewed LRA Table 4.3-6 and noted that the 40-year CUF value and 60-year CUF value for 12-in. RHR pump suction isolation valves are 0.64 and 0.96, respectively. The applicant stated that the fatigue usage factors in these valves do not depend on effects that are time-dependent at steady-state conditions but depend only on effects of operational, abnormal, and upset transient events. The staff noted that so long as the number of transients that occur at the site remain bounded by the 40-year numbers of cycles assumed by the analysis, the design basis fatigue evaluation remains valid. The staff noted that the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program ensures that the numbers of transients actually experienced during the period of extended operation remain below the assumed number or that corrective actions will be taken. The staff's evaluation of the Metal Fatigue of Reactor Coolant Pressure Boundary Program is documented in SER Section 3.0.3.2.28.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging related to fatigue analysis of the 12-in. RHR pump suction isolation valves will be adequately managed for the period of extended operation. Additionally, the applicant's disposition meets the acceptance criteria in SRP-LR Section 4.3.2.1.1.3 because the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program monitors and tracks the number design basis transients that will occur through the period of extended operation and includes action limits and corrective actions that will ensure that the Code design limit of 1.0 will not be exceeded during the period of extended operation. Additionally, the use of the applicant's program is consistent with the recommendations of GALL Report AMP X.M1.

4.3.2.6.3 UFSAR Supplement

LRA Section A3.2.1.6 provides the UFSAR supplement summarizing the metal fatigue TLAAs for the Class 1 valves. The staff reviewed LRA Section A3.2.1.6, consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the reviewer confirms that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA. As discussed above in RAI 4.3-22, the staff requested that the applicant provide a disposition in accordance with 10 CFR 54.21(c)(1) for the fatigue TLAAs related to the "8-inch Lo-Head Safety Injection Train A/B/C To Loop 1(2)A/B/C Cold Leg Check Valve" and the "3-inch [by] 6-inch Pressurizer Power Operated Relief Valve" and any appropriate revisions to the LRA. In its response dated November 21, 2011, the applicant amended LRA Section A3.2.1.6 to disposition the fatigue TLAAs for these two valves, in accordance with 10 CFR 54.21(c)(1)(ii).

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the metal fatigue TLAAs for ASME Code Section III Class 1 valves, as required by 10 CFR 54.21(d).

4.3.2.6.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(ii), that the cumulative fatigue analyses for the ASME Code Section III Class 1 valves, except the RHR pump suction isolation valves, have been projected to the end of the period of extended operation. The staff also concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the cumulative fatigue analyses for the RHR pump suction isolation valves will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.2.7 ASME Code Class 1 Piping and Nozzles

4.3.2.7.1 Summary of Technical Information in the Application

LRA Section 4.3.2.7 describes the applicant’s metal fatigue TLAA for the ASME Code Section III Class 1 piping and piping nozzles. The applicant stated its Class 1 reactor coolant main loop piping, surge line piping, and other ASME Code Section III Class 1 piping is designed to ASME Code Section III, Subsection NB, 1974 edition with addenda through winter 1975. In addition, the Class 1 piping fatigue analyses were performed to the ASME Code Section III, Subsections NB-3200 and 3600, 1974 edition with addenda through winter 1975. The applicant stated that all Class 1 piping, Class 1 nozzles, and Class 1 thermowells were analyzed using the 40-year design transients, and the most limiting calculated design basis usage factors occur in the 6-in. pressurizer safety lines and approach the limit of 1.0.

The applicant dispositioned the TLAAs for ASME Code Section III Class 1 piping and piping nozzles in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the ASME Code Section III Class 1 piping, piping nozzles, and thermowells will be adequately managed by the Metal Fatigue of Reactor Coolant Pressure Boundary Program for the period of extended operation.

4.3.2.7.2 Staff Evaluation

The staff reviewed LRA Section 4.3.2.7 and the TLAAs for the ASME Code Section III Class 1 piping and piping nozzles to confirm, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue will be adequately managed by the Metal Fatigue of Reactor Coolant Pressure Boundary Program for the period of extended operation.

The staff reviewed the applicant’s TLAA for ASME Code Section III Class 1 piping and piping nozzles and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with the review procedures in SRP-LR Section 4.3.3.1.1.3. These procedures state that the reviewer should confirm the appropriateness of the applicant’s program for monitoring and tracking the number of critical thermal and pressure transients for the selected RCS components.

LRA Sections 4.3.2.7 and A3.2.1.7 state that fatigue usage factors in ASME Code Section III Class 1 piping and piping nozzles do not depend on effects that are time-dependent at steady-state conditions but depend only on effects of normal, upset, and emergency transient events. Furthermore, the Metal Fatigue of Reactor Coolant Pressure Boundary Program ensures that the numbers of transients actually experienced during the period of extended operation remain below the assumed number. However, LRA Section 4.3.1.1 states that the ASME Code does not require inclusion of emergency or faulted conditions in fatigue evaluations; therefore, the Metal Fatigue of Reactor Coolant Pressure Boundary Program does not monitor emergency and faulted conditions. The staff reviewed UFSAR Section 3.9.1.1.8 and noted that the small loss-of-coolant accident, small steam line break, and complete loss of flow transients are considered emergency conditions, but they are not listed in LRA Table 4.3-2. By letter September 22, 2011, the staff issued RAI 4.3-9 requesting that the applicant clarify whether emergency conditions are included in the fatigue analyses of ASME Code Section III Class 1 piping and piping nozzles. If so, the applicant was requested to justify why the Metal

Fatigue of Reactor Coolant Pressure Boundary Program does not monitor emergency transients. If not, the applicant was requested to clarify why the dispositions for the fatigue analyses of ASME Code Section III Class 1 piping and piping nozzles in LRA Sections 4.3.2.7 and A3.2.1.7 discuss emergency transients. RAI 4.3-9 also requested the same information for RVIs, as documented in SER Section 4.3.3.2.

In its response dated November 21, 2011, the applicant stated that ASME Code Section III, paragraph NB-3222.4, requires the inclusion of those transients expected during normal service conditions. Therefore, the emergency conditions noted in the staff's question (small loss-of coolant accident, small steam line break, and complete loss of flow) are not required to be included in the ASME Code Section III Class 1 fatigue analyses. In addition, the applicant stated that emergency transients would constitute a significant event and would require initiation of a corrective action document and thorough analysis of the event; therefore, emergency transients do not need to be monitored.

The staff finds the applicant's response acceptable because, consistent with ASME Code Section III, emergency and faulted conditions are not required to be considered in fatigue analyses for ASME Code Section III Class 1 piping and would not be a contributor to the calculated CUF value. Therefore, consistent with the recommendations of GALL Report AMP X.M1, the applicant is monitoring those plant design transients that cause cyclic strains, which are significant contributors to the fatigue usage factor. The staff's concern described in RAI 4.3-9 related to ASME Code Section III Class 1 piping is resolved.

The staff noted that the design basis fatigue evaluation remains valid as long as the number of transients that occur at the site remain bounded by the 40-year numbers of cycles assumed by the analysis. The staff noted that the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program ensures that the numbers of transients actually experienced during the period of extended operation remain below the assumed number or corrective actions will be taken. The staff's evaluation of the Metal Fatigue of Reactor Coolant Pressure Boundary Program is documented in SER Section 3.0.3.2.28.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging related to fatigue analyses for ASME Code Section III Class 1 piping and piping nozzles will be adequately managed for the period of extended operation. Additionally, the applicant's disposition meets the acceptance criteria in SRP-LR Section 4.3.2.1.1.3 because the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program monitors and tracks the number design basis transients that will occur through the period of extended operation and includes action limits and corrective actions that will ensure that the ASME Code design limit of 1.0 will not be exceeded during the period of extended operation. Additionally, the use of the applicant's program is consistent with the recommendations of GALL Report AMP X.M1.

4.3.2.7.3 UFSAR Supplement

LRA Section A3.2.1.7 provides the UFSAR supplement summarizing the metal fatigue TLAA for the ASME Code Section III Class 1 piping and piping nozzles. The staff reviewed LRA Section A3.2.1.7, consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the reviewer confirms that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the metal fatigue TLAA for ASME Code Section III Class 1 piping and piping nozzles, as required by 10 CFR 54.21(d).

4.3.2.7.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the cumulative fatigue analyses for the ASME Code Section III Class 1 piping and piping nozzles will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.2.8 Response to NRC Bulletin 88-08: Intermittent Thermal Cycles due to Thermal-Cycle-Driven Interface Valve Leaks and Similar Cyclic Phenomena

4.3.2.8.1 Summary of Technical Information in the Application

LRA Section 4.3.2.8 describes the applicant’s TLAA associated with the response to NRC Bulletin 88-08. The applicant stated that NRC Bulletin 88-08 describes the mechanism of thermal cycles in normally-isolated, dead-end branches, due to leaking interface valves. Because valves often leak, an unrecognized phenomenon and possibly unanalyzed cyclic thermal stresses on valves, piping, and nozzles may exist for those reactors with these conditions. Under these conditions, thermal fatigue of the un-isolable piping can result in crack initiation.

The applicant stated, for the RHR Lines, that Westinghouse compared the STP and Genkai RHR lines and determined that it is very unlikely for thermal cycling phenomenon, as described in NRC Bulletin 88-08, supplement 3, to occur. Therefore, the safety determination does not consider the effects of aging, and the evaluation of the RHR line is not a TLAA in accordance with 10 CFR 54.3(a), Criterion 2. The applicant dispositioned the TLAAs for charging, alternate charging, and auxiliary spray lines due to thermal stratification in accordance with 10 CFR 54.21(c)(1)(ii), that the analyses have been projected to the end of the period of extended operation.

4.3.2.8.2 Staff Evaluation

The staff reviewed LRA Section 4.3.2.8 and the metal fatigue TLAA associated with the applicant’s response to NRC Bulletin 88-08 to confirm, pursuant to 10 CFR 54.21(c)(1)(ii), that the analyses have been projected to the end of the period of extended operation. In addition, the staff reviewed the applicant’s determination that the evaluation for the RHR lines is not a TLAA in accordance with 10 CFR 54.3(a), Criterion 2.

The staff also reviewed the applicant’s TLAAs for the charging, alternate charging, and auxiliary spray lines due to thermal stratification and the corresponding disposition of 10 CFR 54.21(c)(1)(ii), consistent with the review procedures in SRP-LR Section 4.3.3.1.1.2. These procedures state that the revised CUF calculations are reviewed to ensure that the CUF remains less than or equal to 1.0 at the end of the period of extended operation.

LRA Section 4.3.2.8 states that the NRC safety evaluation of the STP lines concluded that the normal charging, alternate charging, and the auxiliary spray lines at STP are not susceptible to thermal cycling. The LRA further states the analyses that support inspection interval determinations for these lines are independent of the life of the plant, and thus they are not TLAAs in accordance with 10 CFR 54.3(a), Criterion 3, in that the fatigue analyses do not involve a time-limited assumption.

The staff reviewed the SE related to the resolution of Bulletin 88-08, dated May 6, 1998 (ADAMS Accession No. 9805110004). Based on its review, the staff noted that the applicant estimated that the CUF limit of 1.0, when considering design transients and inadvertent thermal stratification cycling, would be achieved in a time span of 11.4 years based on a fatigue evaluation performed by Westinghouse of the weld between the check valve and the unisolable piping. In this SE, the staff noted that the time span was calculated using the assumption that thermal cycling occurred at the check valve weld and that the ASME Code CUF limit would not be achieved at the weld during the life of the 40-year plant without the assumption of thermal cycling. It is not clear to the staff why the fatigue analyses performed by the applicant, which included time-limited assumptions, would not be defined as a TLAA, in accordance with 10 CFR 54.3(a).

By letter dated September 22, 2011 the staff issued RAI 4.3-21, requesting that the applicant justify why the fatigue analyses related to thermal cycling, as discussed in the staff's SE dated May 6, 1998, were not identified as TLAAs, as defined in 10 CFR 54.3(a). Otherwise, the applicant was asked to provide and justify the TLAA disposition for the fatigue analyses of the weld between the check valve and the unisolable piping related to thermal cycling for the normal charging, alternate charging, and the auxiliary spray lines.

In its response dated November 21, 2011 the applicant stated the analysis noted in the staff SE related to the resolution of Bulletin 88-08, dated May 6, 1998, was generated to form the interim basis for continuing normal operation at STP assuming thermal cycling at the check valve weld was occurring. The staff noted that the following was concluded in the SE dated May 6, 1998: "The [applicant] has reasonably demonstrated that the normal and alternate charging lines and the auxiliary spray line at STP Units 1 and 2 are not susceptible to the thermal cycling phenomena described in Bulletin 88-08 for the life of the plant, and is therefore not required to monitor these lines for leakage."

Based on its review and the staff's conclusions in the SE dated May 6, 1998, the staff finds the applicant's response acceptable and finds that the fatigue analysis described above is not part of the applicant's CLB and is not a TLAA in accordance with 10 CFR 54.3(a), Criterion 6. The staff's concern described in RAI 4.3-21 is resolved.

The staff noted that, for the RHR lines, the applicant stated Westinghouse compared the STP and Genkai RHR lines and determined that it is very unlikely for the thermal cycling phenomenon described in NRC Bulletin 88-08, supplement 3, to occur at STP. The staff reviewed Section 2.2.2 of the SE related to the resolution of Bulletin 88-08, dated May 6, 1998, which states the RHR lines were shown by Westinghouse to not be susceptible to the phenomenon in supplement 3 of NRC Bulletin 88-08 because of the sufficient distance of the isolation valves from the turbulent penetration source. The staff, in its SE, found this to be reasonable and acceptable and considered the issued resolved for the STP RHR lines. Since it was determined that these RHR lines are not susceptible to the phenomenon in supplement 3 of NRC Bulletin 88-08, the staff finds acceptable the applicant's determination that this evaluation is not a TLAA in accordance with 10 CFR 54.3(a), Criterion 2.

LRA Section 4.3.2.8 states that the applicant evaluated the observed stratification of the charging, alternate charging, and auxiliary spray lines and determined that the incremental fatigue usage increase was less than 0.001 for the charging and alternate charging lines and less than 0.03 for of the auxiliary spray lines. In addition, these evaluations demonstrated that the ASME Code limit would not be reached during the life of the plant since they are based on 40-year design transient cycles.

After reviewing the CUF values for the lines in the LRA and UFSAR Section 3, the staff noted that, when projected out to 60 years considering the increased incremental fatigue usage, the 60-year CUF values are still less than the ASME Code design limit of 1.0. During its audit, the staff confirmed that the low usage factors of these lines, when considering thermal stratification, would not exceed the ASME Code design limit of 1.0 when projected to 60 years. The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the analyses for thermal stratification of the charging, alternate charging, and auxiliary spray lines have been projected to the end of the period of extended operation. Additionally, the applicant's disposition meets the acceptance criteria of SRP-LR Section 4.3.2.1.1.2 because the applicant has demonstrated that the 60-year projected CUF values will be less than the ASME Code, Section III, design limit of 1.0 through the period of extended operation.

4.3.2.8.3 UFSAR Supplement

LRA Section A3.2.1.8 provides the UFSAR supplement summarizing the metal fatigue TLAA in response to Bulletin 88-08. The staff reviewed LRA Section A3.2.1.8, consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the reviewer confirms that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the for the pressurizer surge line, including thermal stratification, as required by 10 CFR 54.21(d).

4.3.2.8.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(ii), that the analyses associated with the applicant's response to NRC Bulletin 88-08 to address thermal cycles of the charging, alternate charging, and auxiliary spray lines have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.2.9 Response to NRC Bulletin 88-11: Revised Fatigue Analysis of the Pressurizer Surge Line for Thermal Cycling and Stratification

4.3.2.9.1 Summary of Technical Information in the Application

LRA Section 4.3.2.9 describes the applicant's metal fatigue TLAA for the pressurizer surge line to account for thermal cycling and stratification in response to NRC Bulletin 88-11. The applicant stated that NRC Bulletin 88-11 requested that applicants establish and implement a program to confirm pressurizer surge line integrity in view of the occurrence of thermal stratification and require addressees to inform the NRC staff of the actions taken to resolve this issue. The applicant stated that the surge line was originally designed to ASME Code

Section III, 1974 edition with addenda through winter 1975 and was re-evaluated to the 1986 Code in response to the NRC Bulletin 88-11 thermal stratification concerns.

The applicant dispositioned the metal fatigue TLAA for the pressurizer surge line to account for thermal cycling and stratification, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the pressurizer surge line, including thermal cycling and stratification, will be adequately managed by the Metal Fatigue of Reactor Coolant Pressure Boundary Program for the period of extended operation.

4.3.2.9.2 Staff Evaluation

The staff reviewed LRA Section 4.3.2.3 and the metal fatigue TLAA for the pressurizer surge line, including thermal cycling and stratification, to confirm, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue will be adequately managed by the Metal Fatigue of Reactor Coolant Pressure Boundary Program for the period of extended operation.

The staff reviewed the applicant's TLAA for the pressurizer surge line, including thermal cycling and stratification, and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with the review procedures in SRP-LR Section 4.3.3.1.1.3. These procedures state that the reviewer should confirm the appropriateness of the applicant's program for monitoring and tracking the number of critical thermal and pressure transients for the selected RCS components.

The applicant stated that, in response to NRC Bulletin 88-11, Westinghouse performed a generic analysis of all domestic Westinghouse PWRs and a plant-specific evaluation of the STP pressurizer surge lines. In addition, the Surge Line Stratification Program for Units 1 and 2 performed ASME Code Section III stress, fatigue CUF, fatigue crack growth, and LBB analyses. The staff noted that the applicant's fatigue crack growth and LBB analyses for the pressurizer surge line are evaluated in SER Section 4.3.2.11.2. The applicant also stated that the new fatigue usage factors were calculated with thermal transients redefined to account for thermal stratification, and the design basis number of cyclic events was unchanged. However, a simplified elastic-plastic analysis was performed in accordance with ASME Code Section III, paragraph NB-3653.6, which resulted in a lower CUF than previous evaluations. The staff noted that a simplified elastic-plastic analysis performed per NB-3653.6 is an alternative analysis, permitted by ASME Code Section III, that may still allow the component to be qualified under NB-3650, "Analysis of Piping Products."

The applicant stated that the revised fatigue analyses, which incorporate thermal stratification, do not depend on effects that are time-dependent at steady-state conditions but depend only on effects of operational, abnormal, and upset transient conditions. The staff noted that, as long as the numbers of transients that occur per unit remain bounded by the 40-year numbers of cycles assumed by the analysis, the design basis fatigue evaluation remains valid. The staff noted that the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program ensures that the numbers of transients actually experienced during the period of extended operation remain below the assumed number or that corrective actions will be taken. The staff's evaluation of the Metal Fatigue of Reactor Coolant Pressure Boundary Program is documented in SER Section 3.0.3.2.28.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging related to fatigue analysis of the pressurizer surge line, including thermal stratification, will be adequately managed for the period of extended operation, because the applicant is managing the number of transient cycles consistent with the 40-year design numbers. Additionally, it meets the acceptance criteria in SRP-LR Section 4.3.2.1.1.3 because the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program monitors and tracks the number design basis transients that will occur through the period of extended operation and includes action limits and corrective actions that will ensure that the ASME Code design limit of 1.0 will not be exceeded during the period of extended operation. Additionally, the use of the applicant's program is consistent with the recommendations of GALL Report AMP X.M1.

4.3.2.9.3 UFSAR Supplement

LRA Section A3.2.1.9 provides the UFSAR supplement summarizing the metal fatigue TLAA for the pressurizer surge line, including thermal stratification. The staff reviewed LRA Section A3.2.1.9, consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the reviewer confirms that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the for the pressurizer surge line, including thermal stratification, as required by 10 CFR 54.21(d).

4.3.2.9.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the pressurizer surge line, including thermal stratification, will be adequately managed by the Metal Fatigue of Reactor Coolant Pressure Boundary Program for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.2.10 High-Energy Line Break Postulation Based on Fatigue Cumulative Usage Factor

4.3.2.10.1 Summary of Technical Information in the Application

LRA Section 4.3.2.10 describes the applicant's TLAA for high-energy line break postulation based on fatigue CUF. The applicant stated that the staff's Branch Technical Position (BTP) MEB 3-1 from the SRP-LR provides guidance for determining the types and locations of postulated high-energy line breaks outside containment and has historically been used for the same purpose inside containment. BTP MEB 3-1 guidance for ASME Code Section III Class 1 piping requires postulating breaks at intermediate locations where the design basis usage factor equals or exceeds 0.1. In addition, UFSAR Section 3.6.1 states that selection of pipe failure locations and evaluation of the consequences on nearby essential systems, components, and structures are presented and are in accordance with the requirements of 10 CFR Part 50, Appendix A, GDC 4. Selections and evaluations comply with the guidance of NRC BTP MEB 3-1.

The applicant dispositioned the TLAA for the welded attachments to Class 2 and 3 piping, which support the elimination of arbitrary intermediate break locations, other than those for the charging system and the main feedwater system, in accordance with 10 CFR 54.21(c)(1)(ii), that the analyses have been projected to the end of the period of extended operation. The applicant also dispositioned the TLAA for the Class 1 break locations and welded attachments to charging and main feedwater lines in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the RVIs will be adequately managed by the Metal Fatigue of Reactor Coolant Pressure Boundary Program for the period of extended operation.

4.3.2.10.2 Staff Evaluation

The staff reviewed LRA Section 4.3.2.10 and the TLAAs for high-energy line break postulation based on fatigue CUF to confirm, pursuant to 10 CFR 54.21(c)(1)(ii), that the analyses have been projected to the end of the period of extended operation for those locations identified as such in the LRA. The staff also confirmed, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue will be adequately managed by the Metal Fatigue of Reactor Coolant Pressure Boundary Program for the period of extended operation for those locations identified as such in the LRA.

The staff reviewed the applicant's metal fatigue TLAA for the welded attachments to Class 2 and 3 piping other than those for the charging system and the main feedwater system and the corresponding disposition of 10 CFR 54.21(c)(1)(ii), consistent with the review procedures in SRP-LR Section 4.3.3.1.1.2. These procedures state that the revised CUF calculations are reviewed to ensure that the CUF remains less than or equal to one at the end of the period of extended operation.

The staff also reviewed the applicant's TLAA for the Class 1 break locations and welded attachments to charging and main feedwater lines and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with the review procedures in SRP-LR Section 4.3.3.1.1.3. These procedures state that the reviewer should confirm the appropriateness of the applicant's program for monitoring and tracking the number of critical thermal and pressure transients for the selected RCS components.

In the fatigue analyses performed to postulate pipe break location for Class 2 and 3 systems, the applicant identified five CUF values that were calculated for integral welded attachments of Class 2 and 3 piping supports. The applicant stated that two of the five welded attachments–in the main feedwater system and in the charging system–will possibly experience CUFs greater than 1.0 during the period of extended operation. The remaining three Class 2 and 3 weld attachments of piping supports are validated for license renewal because their 60-year CUF values show a large margin from 1.0.

The staff noted that LRA Section 4.3.2.10 did not provide the 40-year CUF and corresponding 60-year projected CUF values for the integral pipe supports, other than those for the charging system and the main feedwater system, to support the applicant's disposition in accordance with 10 CFR 54.21(c)(1)(ii). Therefore, the staff could not confirm the adequacy of the applicant's TLAA disposition. By letter dated September 22, 2011, the staff issued RAI 4.3-3, requesting that the applicant provide the 40-year CUF and corresponding 60-year projected CUF values in the fatigue analysis for those welded attachments to Class 2 and Class 3 piping. The staff also asked the applicant to justify the disposition for this TLAA in accordance with 10 CFR 54.21 (c)(1)(ii), in that the analyses have been projected to the end of the period of extended operation.

In its response dated November 21, 2011, the applicant provided the 40-year and 60-year CUF values for the welded attachment to Class 2 and 3 piping. Specifically, for CVCS letdown, the 40-year CUF and 60-year CUF were 0.3704 and 0.5556, respectively. For auxiliary feedwater, the 40-year CUF and 60-year CUF were 0.4385 and 0.65775, respectively. For main steam, the 40-year CUF and 60-year CUF were 0.0985 and 0.14775, respectively. The staff noted that that the 40-year CUF values were projected to 60-years by multiplying by 1.5, which demonstrated that the ASME Code design limit of 1.0 was not exceeded. The staff finds the use of this 1.5 factor reasonable for the 40-year design CUF values because the resulting estimated 60-year CUF values provides a gauge of how much margin is available before the design limit of 1.0 is reached. For these welded attachments, the staff noted that there is 34 percent margin or more between the 60-year projected CUF values and the ASME Code design limit of 1.0.

The staff finds the applicant's response acceptable because the applicant provided the CUF values for the welded attachments that were dispositioned in accordance with 10 CFR 54.21(c)(1)(ii) and demonstrated that, even when projected to 60-years, there is margin before the ASME Code design limit of 1.0 is exceeded for these welded attachments.

The staff finds that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the analyses for the welded attachments to Class 2 and 3 piping, other than those for the charging system and the main feedwater system, have been projected to the end of the period of extended operation. Additionally, it meets the acceptance criteria of SRP-LR Section 4.3.2.1.1.2 because the applicant has demonstrated that the 60-year projected CUF values will be less than the ASME Code Section III design limit of 1.0 through the period of extended operation with significant margin.

For the main feedwater piping support and the charging system piping support, the applicant was not able to demonstrate that the analyses would be valid for the period of extended operation; therefore, the applicant will manage the effects of aging with its Metal Fatigue of Reactor Coolant Pressure Boundary Program for the period of extended operation. The staff's evaluation on the use of this program to manage metal fatigue for these two supports is discussed below.

The staff noted that a CUF value less than 0.1 is one criterion for high energy line break (HELB) location selection that is discussed in UFSAR Section 3.6.2.1.1. It also noted that, for the pressurizer surge line and accumulator safety injection lines, the applicant uses a criterion of 0.4 instead of 0.1 for the CUF value. In addition, it was noted that it may be possible that the design cycle limit applicable to HELB piping locations can be less than the "UFSAR Design Cycles" and "Program Limiting Value" identified in LRA Table 4.3-2. The "acceptance criteria" program element in the Metal Fatigue of Reactor Coolant Pressure Boundary Program did not address how the acceptance criteria will be different for HELB and cumulative fatigue damage. The applicant's program indicates that, when the accumulated cycles approach the design cycles, corrective actions will be taken to ensure the analyzed number of cycles is not exceeded; however, it is not clear to the staff if the applicant's program addresses the situation when the accumulated cycles approach the limit in the HELB analyses.

By letter dated September 22, 2011, the staff issued RAI 4.3-2, requesting that the applicant identify the ASME Code Class 1 piping locations discussed in UFSAR Section 3.6.2.1.1 that are within the scope of LRA Section 4.3.2.10. For each location identified, the staff asked the applicant to provide the applicable design basis transients and associated cycle limits. In addition, the applicant was asked to justify that the Metal Fatigue of Reactor Coolant Pressure Boundary Program can adequately ensure the CUF for HELB locations remains below 0.1 (or 0.4 for the pressurizer surge line and the accumulator safety injection line) by using systematic counting of plant transient cycles associated with the HELB analysis.

In its response dated November 21, 2011, the applicant stated that all ASME Code Class 1 piping locations are within the scope of LRA Section 4.3.2.10 except the reactor coolant loops, which were excluded based on the LBB analysis discussed in LRA Section 4.3.2.11. The applicant clarified that the fatigue analyses that support the determination of the HELB location are discussed in LRA Section 4.3.2.7, and the specific HELB locations are identified in UFSAR Table 3.6.2-1 and Figure 3.6.1-1.

The applicant stated that most of these transients are already considered in the Metal Fatigue of Reactor Coolant Pressure Boundary Program. However, some transient counts assumed in the analyses are less than the program limiting values presented in LRA Table 4.3-2, and the program limiting values will be revised to include these lower values to ensure that corrective actions will be taken for the respective components prior to reaching their lower values. The applicant provided the revision to LRA Table 4.3-2, and the staff confirmed that the revision is consistent with the limiting values used in the fatigue analyses that support the determination of HELB locations. Certain transients are included in these fatigue analyses but are not included in Metal Fatigue of Reactor Coolant Pressure Boundary Program. The staff's assessment as to whether it is acceptable that each of these transients is not included in Metal Fatigue of Reactor Coolant Pressure Boundary Program is documented below.

The "reduce temperature return to power" transient was included in pressurizer surge line and spray line fatigue analyses, and this transient is designed to improve capabilities of the plant during load follow operations. In addition, the "charging flow 50% decrease and return" and "letdown flow 50% increase and return" transients were included in the normal and alternate charging line fatigue analyses. These transients are designed to compensate for RCS volume changes resulting from changes in reactor power, and the number of transients is based on load follow operations. The applicant stated that it does not practice load follow operations, and this is not applicable to its units' operation. The staff finds it acceptable that the applicant does not monitor those transients that occur during load-following operation because the applicant does not operate as load-following units (i.e., setting the power level of a unit in accordance with the electrical grid); therefore, it is not credible for the occurrences of these transients to approach the design limit. The staff noted that the number of the cycles for transients used in Normal/Charging fatigue analyses is based on alternating between the normal and alternate charging paths and the number of cycles used for this transient, "Charging flow 50% step decrease and return," is 14,400.

The "injection flow temperature change" was included in RCP seal injection line fatigue analyses, which will occur when the charging pump suction is switched back and forth from the volume control tank to the refueling water storage tank. The applicant stated that, as discussed in LRA Section 4.3.2.3, it does not normally operate in this manner, and an inadvertent switching of charging pump suction sources due to equipment failure has not occurred to date. In addition, LRA Section 4.3.2.3 states there have been no events of this transient in the history of its plant operation. The staff finds it reasonable that the applicant does not monitor this transient because the circumstances in which this transient occurs are not consistent with normal plant operation. Additionally, after approximately 24 years of operation, this transient, with a design limit of 180 cycles, has not occurred at the applicant's site.

The "loss of seal injection flow" transient was included in RCP seal injection line fatigue analyses and is assumed to occur 40 times over plant life. The applicant clarified that this transient occurs whenever charging is lost, that there are two types of loss of charging transients, and that each is monitored to a 20-event limit. The staff confirmed that the applicant monitors each of the loss of charging transients (charging trip with prompt return to service and charging trip with delayed return to service) against its respective design limit of 20 cycles. The staff finds it acceptable that the applicant does not specifically monitor the loss of seal injection flow transient because the applicant is managing the two loss of charging transients which result in a loss of seal injection flow, with a combined design limit of 40 cycles (consistent with the design limit for the loss of seal injection flow transient).

The “accumulator check valve testing” transient is assumed to occur every refueling. The staff noted that the “refueling” transient is monitored by the Metal Fatigue of Reactor Coolant Pressure Boundary Program. Based on the table provided in the applicant’s response and LRA Table 4.3-2, the staff confirmed that the design limit of 80 cycles is applicable for both the “refueling” transient and “accumulator check valve testing” transient. The staff finds it reasonable that the “accumulator check valve testing” transient is managed for the period of extended operation because it is managed through monitoring the “refueling” transient that has the same design limit of 80 cycles.

The applicant stated the “letdown flow 50% decrease and return” transient was included in normal and alternate charging line fatigue analyses and is not a normal operating event with the plant at power. The applicant clarified that this transient was included for conservatism and assumed to occur approximately once a week for 40 years. The number experienced will not approach the limit given the conservatism of this assumption; therefore, this transient is not counted in the Metal Fatigue of Reactor Coolant Pressure Boundary Program. The staff noted a design limit of 1,200 cycles were included in the normal and alternate charging line fatigue analyses. It is not clear to the staff what the expected number of cycles is over 60-years for the “letdown flow 50% decrease and return” transient. In addition, if this transient was used as an input into a fatigue TLAA, it is not clear to the staff why this transient does not need to be monitored by the Metal Fatigue of Reactor Coolant Pressure Boundary Program to ensure the analysis remains valid.

By letter dated January 30, 2012, the staff issued RAI 4.3-2a (followup), requesting that the applicant clarify the baseline number of events up to year-end 2008 and the 60-year projected cycles for the “letdown flow 50% decrease and return” transient. In addition, based on the 40-year and 60-year cycles, the staff asked the applicant to justify how it supports the statement in its response that, “the number experienced will not approach the limit given the conservatism of this assumption; therefore, this transient is not counted in the Metal Fatigue of Reactor Coolant Pressure Boundary Program.”

In its response to RAI 4.3-2a (followup) dated February 16, 2012, the applicant clarified that the transient description of “letdown flow 50% decrease and return” should read “letdown flow 70% decrease and return” in the response to RAI 4.3-2 dated November 21, 2011. The applicant explained that the “letdown flow 70% decrease and return transient” was analyzed for 2,000 cycles for 40 years (50 cycles per year times 40 years) and was not the number of projected events. The applicant stated that the “letdown flow 70% decrease and return to normal” transient is not expected to occur because STP operates with continuous letdown at nominal flow, and letdown flow reduction is not part of normal operating practices. Therefore, the 60-year projected events are estimated to be zero for both units.

The staff finds it reasonable that the “letdown flow 70% decrease and return” transient is not monitored by the Metal Fatigue of Reactor Coolant Pressure Boundary Program because the applicant’s normal operating practices, which involve continuous letdown at nominal flow and do not consist of letdown flow reduction, preclude the occurrence of this transient. Hence, there is margin between the analyzed number of 1,200 cycles and the expected number of cycles, zero, to account for unanticipated occurrences of this transient through the period of extended operation. Therefore, the staff finds the applicant's response to RAI 4.3-2a acceptable. The staff's concern described in followup RAI 4.3-2a is resolved.

Based on its review, the staff finds the applicant's response to RAI 4.3-2 acceptable because the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program monitors and tracks the number transients that occur through the period of extended operation, except as justified above, and includes corrective actions to ensure that the design limit will not be exceeded during the period of extended operation. Additionally, the applicant revised the "program limiting value" for each monitored transient to correspond to the lowest number of cycles assumed in the fatigue analyses to ensure corrective actions are taken prior to exceeding these assumptions. The staff's concern described in followup RAI 4.3-2 is resolved.

LRA Section 4.3.2.10 states that the fatigue crack growth analyses for the pressurizer surge line and accumulator safety injection lines established that flaws would not reach the flaw depths allowed in paragraph IWB-3640 of the ASME Code during the plant life. The applicant also stated that the analyses that evaluated fatigue crack growth and CUF in the pressurizer surge line and the accumulator safety injection line depend on the standard number of cycles for a 40-year reactor lifetime. LRA Section 4.3.2.10 provides two TLAA dispositions—"Projection, 10 CFR 54.21(c)(1)(ii)" and "Aging Management, 10 CFR 54.21 (c)(1)(iii)." However, it is not clear to the staff how these analyses for fatigue crack growth were dispositioned.

By letter dated September 22, 2011, the staff issued RAI 4.3-20, requesting that the applicant provide the TLAA disposition for the analyses that evaluated fatigue crack growth of the pressurizer surge line and the accumulator safety injection lines. If the TLAA is dispositioned in accordance with 10 CFR 54.21 (c)(1)(i) or 10 CFR 54.21 (c)(1)(ii), the staff asked the applicant to provide sufficient information related to the fatigue crack growth analyses to justify the selected disposition. In addition, if the TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii) and the Metal Fatigue of Reactor Coolant Pressure Boundary Program will be used, the staff asked the applicant to justify the use of cycle counting for these fatigue crack growth analyses without an update to the cycle counting procedure and the inclusion of enhancements to the applicable program elements.

In its response dated November 21, 2011, the applicant clarified that the fatigue crack growth analyses for the pressurizer surge line and the accumulator safety injection lines are dispositioned in accordance with 10 CFR 54.21 (c)(1)(iii). The applicant also revised LRA Sections 4.3.2.10 and A3.2.1.10 to clarify that these fatigue crack growth analyses for the pressurizer surge line and the accumulator safety injection lines are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii). The staff noted that, in response to RAIs 4.3.2.11-1 and B3.1-3, the Metal Fatigue of Reactor Coolant Pressure Boundary Program was revised to include additional enhancements to manage fatigue flaw growth analyses. The staff's evaluation of the Metal Fatigue of Reactor Coolant Pressure Boundary Program is documented in SER Section 3.0.3.2.28.

The staff finds the applicant's response acceptable because the applicant dispositioned the fatigue crack growth analyses for the pressurizer surge line and the accumulator safety injection lines, as required by 10 CFR 54.21(c)(1). Additionally, the applicant is ensuring these analyses remain valid during the period of extended operation on an ongoing basis by confirming the assumptions (number of transient cycles) are not exceeded with its Metal Fatigue of Reactor Coolant Pressure Boundary Program. The staff's concern described in RAI 4.3-20 is resolved.

The staff noted that the analyses associated with the welded attachments to charging and main feedwater lines, HELB postulation based on CUF, the fatigue crack growth for the pressurizer surge line and the accumulator safety injection lines have been dispositioned in accordance with 10 CFR 54.21(c)(1)(iii). It credits the Metal Fatigue of Reactor Coolant Pressure Boundary Program to manage aging through the period of extended operation. The staff noted that as long as the number of transients that occur at the site remain bounded by the 40-year numbers of cycles assumed in these analyses, the evaluation remains valid. The staff noted that the applicant's AMP ensures that the numbers of transients actually experienced during the period of extended operation remain below the assumed number or that corrective actions are taken. The staff's evaluation of the Metal Fatigue of Reactor Coolant Pressure Boundary Program is documented in SER Section 3.0.3.2.28.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the welded attachments to charging and main feedwater lines, HELB postulated locations based on CUF, and pressurizer surge line and the accumulator safety injection lines analyzed for fatigue crack growth will be adequately managed for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.3.2.1.1.3 because the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program monitors and tracks the number design basis transients that will occur through the period of extended operation and includes action limits and corrective actions that will ensure that theses analyses remain valid during the period of extended operation.

4.3.2.10.3 UFSAR Supplement

LRA Section A3.2.1.10 provides the UFSAR supplement summarizing the TLAA for welded attachments to Class 2 and 3 lines, HELB postulation based on CUF, and fatigue crack growth of the pressurizer surge line and the accumulator safety injection lines. The staff reviewed LRA Section A3.2.1.10, consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the reviewer confirms that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA for welded attachments to Class 2 and 3 lines, HELB postulation based on CUF, and fatigue crack growth of the pressurizer surge line and the accumulator safety injection lines, as required by 10 CFR 54.21(d).

4.3.2.10.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(ii), that the fatigue analyses for welded attachments to Class 2 and 3 piping, which support the elimination of arbitrary intermediate break locations other than those for the charging system and the main feedwater system, have been projected to the end of the period of extended operation. In addition, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the welded attachments to charging and main feedwater lines, fatigue on HELB postulated locations based on CUF, and fatigue crack growth for the pressurizer surge line and the accumulator safety injection lines will be adequately managed for the period of extended operation. The staff also concludes that the

UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.2.11 Fatigue Crack Growth Assessments and Fracture Mechanics Stability Analyses for Leak-Before-Break (LBB) Elimination of Dynamic Effects of Primary Loop Piping Failures

4.3.2.11.1 Summary of Technical Information in the Application

LRA Section 4.3.2.11 describes the applicant's TLAA for LBB analysis. LRA Section 4.3.2.11 states that an LBB analysis eliminated the need to postulate longitudinal and circumferential breaks in the RCS primary loop piping. Elimination of these breaks omitted the need to install pipe whip restraints in the primary loop and eliminated the requirement to design for dynamic (jet and whip) effects of primary loop breaks. The LBB application will not affect the containment pressurization, emergency core cooling system, and environmental qualification large-break design bases. NRC approved the use of LBB in the RCS primary loop piping in NUREG-0781, supplement 2.

The LBB evaluation included a fatigue crack growth assessment for a range of materials at a high-stress location bounding the primary coolant system. The LBB evaluation concluded that the effects of low- and high-cycle fatigue on the integrity of primary piping are negligible. The Metal Fatigue of the Reactor Coolant Pressure Boundary AMP ensures that the actual transient cycles remain below the assumed transient cycles in the analyses; otherwise, appropriate corrective actions will be taken. The effects of fatigue will, therefore, be managed for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

The LBB analysis also includes a fracture mechanics evaluation, which depends on the crack initiation energy integral, J_{IN}. The primary coolant loops at STP are SA 351 Grade CF8A CASS, which at PWR operating temperatures is subject to time-dependent thermal embrittlement that would reduce the J_{IN}-integral value. Thermal embrittlement effects depend logarithmically on time (more rapid initially and approaching a saturation value over time.) The LBB analysis determined the effects of thermal aging on piping integrity for a material at thermal embrittlement saturation. Therefore, the applicant stated that the fracture mechanics evaluation for the CASS piping components in the LBB application is dependent on material properties not plant life; therefore, it is not a TLAA in accordance with 10 CFR 54.3(a), Criterion 3.

4.3.2.11.2 Staff Evaluation

The staff reviewed fatigue crack growth calculation in LRA Section 4.3.2.11 to confirm, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended function of LBB piping will be adequately managed for the period of extended operation. Although the applicant stated that thermal embrittlement of the CASS piping is not a TLAA, the staff reviewed the issue to confirm, pursuant to 10 CFR 54.21(c)(1)(i), that the fracture mechanics analysis of the CASS LBB piping remains valid during the period of extended operation. The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with the review procedures in SRP-LR Section 4.7.3, which state that the review of the TLAA provides assurance that the aging effect is properly addressed through the period of extended operation.

In RAI 4.3.2.11-1, the staff asked the applicant to list the piping systems that have been approved for LBB and are within the scope of license renewal. By letter dated May 12, 2011, the applicant responded that LBB analyses were performed for the reactor coolant piping, pressurizer surge line piping, safety injection accumulator piping, and the RHR suction piping. The applicant confirmed the specific piping systems that have been approved for LBB, therefore, the staff's concern in RAI 4.3.2.11-1 is resolved.

Thermal Embrittlement of CASS Material in LBB Piping. In RAI 4.3.2.11-2, the staff asked the applicant to clarify whether the saturated (i.e., worst-case) fracture toughness value due to thermal embrittlement was used in the LBB analyses. By letter dated May 12, 2011, the applicant responded that the saturated fracture toughness value was used in all LBB analyses. The applicant stated further that although the fracture mechanics calculation considers aging of the material property, aging is not based on the plant life. Aging is based on the minimum material properties possible, and the value used by the calculation will be the same whether the plant life is 40 years, 60 years, or 100 years. Therefore, the applicant concluded that the fracture mechanics calculation is not a TLAA in accordance with 10 CFR 54.3(a), Criterion 3. Westinghouse Report WCAP-10456, "The Effects of Thermal Aging on the Structural Integrity of Cast Stainless Steel Piping for Westinghouse Nuclear Steam Supply Systems," November 1983, provides equations to predict end-of-life fracture toughness for thermal aging of CASS materials based on silicon, chromium, molybdenum, and ferrite contents. Testing found that the material properties reached saturated conditions after 30,000 hours during a 60,000-hour test. The selection of fracture toughness properties is discussed in enclosure C, item 2 of the applicant's letter dated March 12, 1986, "Alternative Pipe Break Criteria for Pressurizer Surge Line."

The staff noted that the applicant's response to Part 3 of RAI 4.3.2.11-2 cites the 1983 Westinghouse technical report WCAP-10456, "The Effects of Thermal Aging on the Structural Integrity of Cast Stainless Steel Piping for Westinghouse Nuclear Steam Supply Systems," as the basis for the saturated fracture toughness assumed in its analyses. The staff noted further that considerable information has been developed since 1983 to provide improved understanding of the thermal embrittlement of CASS materials, by O. Chopra of Argonne National Laboratory, C. Faidy of Electricité de France, and others. The following documents are examples of such reports that provide data since the 1980's:

- NUREG/CR-4513, Revision 1, "Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems" (1994)
- Appendix A of draft Electric Power Research Institute (EPRI) report 1024966, "Probabilistic Reliability Model for Thermally Aged Cast Austenitic Stainless Steel Piping"
- ASME Code paper PVP2010-25085, "Flaw Evaluation in Elbows Through French RSEM Code [a French Nuclear Code for PWR mechanical equipment]," by C. Faidy

Although the applicant's RAI response states that the material property aging is based on the "minimum material properties possible," the RAI response does not provide justification to support that statement in light of additional information on thermal aging of CASS over the last 29 years. In particular, it does not demonstrate that the aging after 60 years of operation is bounded by the thermal embrittlement saturation values assumed in the existing analysis. To address these issues, the staff issued RAI 4.3.2.11-6 by letter dated November 19, 2012, requesting that the applicant:

- provide justification that the assumed saturated fracture toughness in the CASS LBB evaluations bounds the expected toughness at 60 years of operation, considering the information sources cited above and others as necessary
- specify the information sources used in the response to Part 1

- identify, based on its response to Part 1, whether it will retain the current disposition of the LBB evaluation of CASS piping in LRA Section 4.3.2.11 or will instead treat it as: (a) a TLAA evaluated under 10 CFR 54.21(c)(1)(i) (i.e., the analysis “remains valid for the period of extended operation”); (b) a TLAA evaluated under 10 CFR 54.21(c)(1)(ii) (i.e., the analysis “has been projected to the end of the period of extended operation”); or (c) other determination (please describe in full)

Pending resolution of RAI 4.3.2.11-6, this is being tracked as Open Item (OI) 4.3.2.11-1.

<u>Fatigue Flaw Growth Calculations of LBB Piping</u>. LRA Section 4.3.2.11 states that the Metal Fatigue of the Reactor Coolant Pressure Boundary AMP ensures that the numbers of transients experienced during the period of extended operation remain below the assumed number in the fatigue usage factor analysis. Appropriate corrective actions will maintain the design and licensing basis by other acceptable means. In RAI 4.3.2.11-3, the staff asked the applicant to discuss whether the Metal Fatigue AMP specifically identifies all transients in the LBB analyses that will be monitored and to describe the appropriate corrective actions and other acceptable means that may be taken.

By letter dated May 12, 2011, the applicant responded that the transients used in the LBB analyses are consistent with those transients presented in LRA Table 4.3-2, with the exception of the following two transients not listed in LRA Table 4.3-2. The first transient, “accumulator actuation, accident operation,” is a combination of the “inadvertent RCS depressurization” transient and “LOCA” transient. The “LOCA” transient is a faulted event and, therefore, is not counted. The “inadvertent RCS depressurization” transient listed in Table 4.3-2 is monitored and counted. The second transient, “reduce temperature return to power” is identified in the pressurizer surge line fatigue crack growth analysis but not included in the STP design bases. This transient was designed to improve capabilities of the plant during load follow operations. STP does not practice load follow operations; therefore, this transient is not applicable to STP.

When “other acceptable corrective action” is needed, a 10 CFR 50.59 review is performed in order to determine if the methods and results are in line with the CLB or if regulatory review is needed. The term “appropriate corrective actions” is in reference to the corrective action described in LRA Section B3.1 and LRA Table A4-1, Commitment No. 30. As part of response to RAI 4.3.2.11-3, the applicant revised the corrective actions (Element 7) in LRA Section B3.1, as documented in the applicant’s letter dated May 12, 2011. The staff finds that the revised LRA Section B3.1 provides additional detailed monitoring on the fatigue usage factor calculation and associated corrective actions. The staff finds that the enhanced Metal Fatigue AMP is acceptable to monitor the transient cycles used in the fatigue crack growth calculation for the LBB piping. Therefore, the fatigue aging effect for the LBB piping will be adequately managed for the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(iii). The staff’s evaluation of the Metal Fatigue of Reactor Coolant Pressure Boundary Program is documented in SER Section 3.0.3.2.28. Based on the above evaluation, the staff’s concern described in RAI 4.3.2.11-3 is resolved.

In RAI 4.3.2.11-5, the staff asked the applicant to discuss whether the fracture mechanics calculations and fatigue crack growth calculations for all LBB piping have been updated to include the new loads and design basis events that are discussed in LRA Section 4.3.2.4. By letter dated May 12, 2011, the applicant responded that LRA Section 4.3.2.11 has addressed the effects of power uprate and steam generator replacement on the LBB analysis. The applicant reconciled the LBB analyses with the current plant design basis, including new loads. The evaluation determined that the conclusions of the previous LBB analyses for the reactor coolant piping, pressurizer surge line, and accumulator lines remain valid. The staff finds it acceptable that the applicant has evaluated the impact of power uprate and steam generator replacement on the original LBB evaluation and found that the LBB evaluation remains valid. Based on the above evaluation, the staff's concern described in RAI 4.3.2.11-5 is resolved.

Primary Water Stress Corrosion Cracking. The staff notes that NUREG-0800, "Standard Review Plan" (SRP), Section 3.6.3, prohibits the LBB application to piping that experiences active degradation. PWR operating experience has shown that nickel-based Alloy 82/182 weld material is susceptible to PWSCC. In RAI 4.3.2.11-4, the staff asked the applicant to identify the LBB pipes that are constructed using Alloy 82/182 weld metal, identify the LBB pipes with and without mitigated Alloy 82/182 welds, and discuss whether the LBB evaluation has been updated for the mitigated Alloy 82/182 welds.

By letter dated May 12, 2011, the applicant responded that STP, Units 1 and 2, reactor coolant piping (RV inlet and outlet nozzles) and the pressurizer surge line are the LBB lines that contain Alloy 82/182 filler weld metal. The applicant installed SWOLs on the Alloy 82/182 filler weld metal in the STP, Units 1 and 2, pressurizer surge lines in fall 2006 and spring 2007, respectively. Subsequently, the applicant inspected the overlaid surge line welds in fall 2009 for Unit 1 (1RE15) and spring 2010 for Unit 2 (2RE14) and found no flaws. These locations will continue to be inspected every 10 years using a qualified PDI ultrasonic technique.

The applicant stated that the Units 1 and 2 RV inlet and outlet nozzles contain unmitigated Alloy 82/182 filler weld metal, and they will be inspected with a qualified PDI ultrasonic technique in accordance with the ASME Code ISI Program and MRP-139/ASME Code Case N-770-1. The applicant performed ultrasonic testing on the reactor coolant piping inlet and outlet nozzles during 1RE15 and 2RE14 and found no flaws. The hot leg dissimilar metal welds are also visually inspected from the outside diameter every outage per ASME Code Case N-722.

The applicant stated that the LBB evaluations for the Units 1 and 2 pressurizer surge lines were updated to account for the effects of PWSCC in the leak rate calculations. The results of the LBB evaluation for the surge lines show that the LBB margin recommendations of SRP Section 3.6.3 are satisfied. The applicant stated further that the original LBB analysis conclusions remain valid.

In response to NRC Regulatory Issue Summary (RIS) 2010-007, "Regulatory Requirements for Application of Weld Overlays and Other Mitigation Techniques in Piping Systems Approved for Leak-Before-Break," the applicant is performing a 10 CFR 50.59 evaluation for the overlaid Alloy 82/182 weld in the pressurizer surge line. The applicant stated that the 10 CFR 50.59 review will conclude that the methodology used for the updated LBB analysis is the same method the NRC staff approved for use at Waterford Unit 3, as documented in its SE dated February 28, 2011 (ADAMS Accession No. ML110410119).

The staff finds that because the Alloy 82/182 dissimilar metal welds at the main primary loop nozzles have not yet been mitigated, the inspection of unmitigated Alloy 82/182 welds will be more frequent than if the welds were mitigated as discussed in ASME Code Case N-770-1 with conditions in 10 CFR 50.55a. The applicant is required to inspect the welds at the primary loop nozzles in accordance with ASME Code Case N-770-1, with conditions as required in 10 CFR 50.55a.

As stated above, the applicant's 10 CFR 50.59 evaluation of the updated LBB analysis for the surge line is ongoing. The staff notes that the 10 CFR 50.59 evaluation of the updated LBB analysis is not directly related to the TLAA requirements of 10 CFR 54.21(c)(1). The staff finds it is acceptable that the applicant has installed weld overlays on and updated LBB analysis for the pressurizer surge line, and it will perform necessary inspections to manage PWSCC in LBB piping with unmitigated Alloy 82/182 welds. Based on the above evaluation, the staff's concern described in RAI 4.3.2.11-4 is resolved.

4.3.2.11.3 UFSAR Supplement

LRA Section A3.2.1.11 provides the UFSAR supplement summarizing a description of the TLAA of the fatigue crack growth assessments and fracture mechanics stability analyses for the LBB piping. The staff reviewed LRA Section A3.2.1.11, consistent with the review procedures in SRP-LR Section 4.7.3.2, which state that the staff confirms that the UFSAR supplement includes a summary description of the evaluation of each TLAA. Based on its review of the UFSAR supplement, the staff finds that it meets the acceptance criteria in SRP-LR Section 4.7.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA of the fatigue crack growth assessments and fracture mechanics stability analyses for the LBB piping, as required by 10 CFR 54.21(d).

4.3.2.11.4 Conclusion

On the basis of its review, the staff concludes that, pursuant to 10 CFR 54.21(c)(1)(iii), the applicant has demonstrated that the effects of fatigue crack growth on the intended function of LBB piping will be adequately managed for the period of extended operation. Although the applicant concluded that the fracture mechanics calculation for the CASS material is not a TLAA, the staff finds that the applicant has performed a TLAA that shows that the fracture mechanics calculation of CASS material remains valid for the period of extended operation because the saturated fracture toughness of CASS was used. The staff concludes that, pursuant to 10 CFR 54.21(c)(1)(i) and pending successful resolution of OI 4.3.2.11-1, the applicant has demonstrated that the fracture mechanics analysis of CASS primary coolant loop piping remains valid for the period of extended operation. The staff concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation of the subject LBB piping, as required by 10 CFR 54.21(d).

4.3.2.12 Class 1 Design of Class 3 Feedwater Control Valves

4.3.2.12.1 Summary of Technical Information in the Application

LRA Section 4.3.2.12 describes the applicant's metal fatigue TLAA for the Class 3 feedwater control valves with a Class 1 design. The applicant stated that its feedwater control valves were purchased as ASME Code Section III, Class 3 valves, and UFSAR Table 3.9-8 associates a limiting number of occurrences of unit loading and unloading at 5 percent of full power for these valves. In addition, the methods and acceptance criteria for the evaluation of the valves for these occurrences were based on Class 1 methods of paragraph NB-3545 of ASME Code Section III, 1977 edition through the winter 1978 addenda.

The applicant dispositioned the metal fatigue TLAA for the Class 3 feedwater control valves with a Class 1 design in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

4.3.2.12.2 Staff Evaluation

The staff reviewed LRA Section 4.3.2.12 and the TLAA for the Class 3 feedwater control valves with a Class 1 design to confirm, pursuant to 10 CFR 54.21(c)(1)(i), that the analysis remains valid during the period of extended operation.

The staff reviewed the applicant's TLAAs for the thermal Class 3 feedwater control valves with a Class 1 design and the corresponding disposition of 10 CFR 54.21(c)(1)(i), consistent with the review procedures in SRP-LR Section 4.3.3.1.1.1. These procedures state that the operating transient experience and a list of the assumed transients used in the existing CUF calculations for the current operating term are reviewed to ensure that the number of assumed transients would not be exceeded during the period of extended operation.

LRA Section 4.3.2.12 states that the main feedwater control valves were analyzed for a new set of operating design transient conditions during the replacement steam generator project, and it was found that they could not be qualified for the full number of loading and unloading transients defined for the life of the plant. In order to obtain acceptable fatigue limits, the number of loadings and unloadings between 15 and 100 percent power was reduced, by the applicant, from 13,200 to 10,300 of loading or unloading.

The applicant stated that it has experienced 62 occurrences of this transient for Unit 1 and 43 occurrences for Unit 2 through July 27, 1989, which are less than 17 percent of the 385 anticipated at that point in the design life. Using the same occurrence rate, the 60-year projected occurrence will be 3,366 events. The applicant stated that this demonstrates a large margin between the analyzed value, 10,300, and the number of projected cycles of 3,366; thus, the analysis is valid for the period of extended operation.

The staff noted that the operating license for Unit 1 was issued on March 22, 1988, and on March 28, 1989, for Unit 2. In addition, LRA Table 4.3-2 provides the "Program Limiting Value" for the unit loading and unloading transients (Transients 5 and 6) of 3,000 for Unit 1 and 10,300 for Unit 2. The staff reviewed the information provided in LRA Section 4.3.2.12. However, it is not clear whether the use of the 16-month (from March 1988 to July, 1989) data for Unit 1 and 4-month (March 28, 1989, to July 27, 1989) data for Unit 2 to extrapolate the number of occurrences of unit loading and unloading transients for 60 years is either reasonable or conservative. It is also not clear how the applicant determined that 385 cycles of the loading and unloading transients were anticipated to occur through July 27, 1989. The staff noted that the estimated occurrences of 3,366 cycles for these transients exceeds the "Program Limiting Value" of 3,000, which demonstrates that the applicant's disposition of this TLAA, in accordance with 10 CFR 54.21(c)(1)(i), is not valid.

By letter dated September 22, 2011, the staff issued RAI 4.3-5, requesting that the applicant justify how the 385 cycles of the unit loading and unloading transients that were anticipated to occur through July 27, 1989, was determined for Units 1 and 2. Furthermore, the staff requested that the applicant justify the disposition of the Unit 1 Class 3 feedwater control valves designed to Class 1 methods and provide the CUF contribution for the loading and unloading transients on the feedwater control valves.

In its response dated November 21, 2011, the applicant stated the total transient count for Unit 1 and Unit 2 for the early period (62 and 43, respectively) contain multiple initial startup operational transients that are not expected to be repeated during the remainder of plant life. Based on recent operating history, this transient would typically be expected to occur only one to three times per 18-month cycle. The applicant clarified that the 385 cycles anticipated to occur during the early operating period were calculated by multiplying the original design basis value of 13,200 cycles (based on a load following plant design) by the fraction of life that the plant had experienced. The staff noted the applicant's units are operated as base load plants; therefore, this anticipated number of cycles, which was determined based on a load-following plant, is a highly conservative estimate. In addition, the staff noted that there is a significant margin between the projected number of cycles through the period of extended operation and the design limit of 10,300 cycles for the feedwater control valves, to account for unexpected occurrences. Based on these two factors, the staff finds that the design limit of 10,300 cycles for the feedwater control valves will not be approached through the period of extended operation.

The applicant clarified that the 3,000 cycle "Program Limiting Value," as noted in UFSAR Table 3.9-8, Footnote 2, pertains only to the Unit 1 BMI half-nozzle repair, and the cycle limiting value of 10,300 is still applicable for the Unit 1 Class 3 feedwater control valves. In addition, the total CUF is 0.999 of which loading and unloading events contribute 0.944 and the other transients contribute 0.055 to the 40-year CUF.

The staff noted a discrepancy between the applicant's response and LRA Section 4.3.2.12, which states that "[t]o obtain acceptable fatigue limits the number of loadings and unloadings between 15 and 100 percent power had to be reduced from 13,200 to 10,300, of loading or unloading for Unit 2. **This limit does not apply to design of the Unit 1 feedwater control valves** [emphasis added]." By letter dated January 30, 2012, the staff issued followup RAI 4.3-5a, requesting that the applicant clarify the reference to LRA Section 4.3.1.12 that was cited in response to RAI 4.3-5. In addition, the staff asked the applicant to clarify the discrepancy between the response to RAI 4.3-5 and the information provided in LRA Section 4.3.2.12 for the limit of the number of loadings and unloadings between 15 and 100 percent power for Unit 1.

In its response to RAI 4.3-5a (followup) dated February 16, 2012, the applicant clarified that the reference to LRA Section 4.3.1.12 cited in response to RAI 4.3-5 dated November 21, 2011, should read 4.3.2.12. In addition, the applicant stated that the 10,300-cycle limit for loadings and unloadings between 15 and 100 percent power is applicable to the Unit 1 feedwater control valves. The applicant explained that the number of Unit 1 loading and unloading events between 15 and 100 percent power is limited to 3,000 because of the RV BMI half-nozzle repairs. The staff noted that the Unit 1 feedwater control valves are qualified for 10,300 events by the analysis and that the applicant revised LRA Section 4.3.2.12 to clarify that the 10,300 cycle limiting value applies to both the Unit 1 and Unit 2 feedwater control valves.

The staff noted that the design of the plant, which included the larger number of cycles for the loading and unloading events between 15 and 100 percent power, was intended for a load following plant design; however, the applicant operates its plant as a base-load plant. Therefore, the staff finds it reasonable that the design cycle limit of 10,300 for the feedwater control valves will be not be exceeded based on the way in which the applicant operates its plant. In addition, since the contribution from the loadings and unloadings between 15 and 100 percent power transient is over 94 percent of the calculated CUF value, the staff finds its highly unlikely that the design CUF of 0.999 will be reached and the ASME Code design limit of 1.0 will be exceeded. The applicant does not operate in such a way to accumulate the design number of cycles for this transient (i.e., operate as a load-following plant).

Based on its review, the staff finds the applicant's responses to RAIs 4.3-5 and 4.3-5a acceptable for the following reasons:

- The estimated number of cycles for the loading and unloading events between 15 and 100 percent power considered the accumulated cycles which occurred at a higher rate during initial startup operation, and considered a reasonable scale to project to 60 years from the number of cycles anticipated from 40 years of operation.
- The estimated number of cycles that are expected to occur through the period of extended operation is less than 33 percent of the program limiting value of 10,300 cycles.
- The margin between the expected number of cycles and the design cycle limit of 10,300 for the feedwater control valves is sufficient to account for any unanticipated occurrences through the period of extended operation so that the cycle limit will not be exceeded.

The staff's concerns described in RAI 4.3-5 and RAI 4.3-5a are resolved.

The staff finds that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses for the Units 1 and 2 feedwater control valves remain valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.7.2.1 because the applicant demonstrated that the analyzed number of cycles for 40-years will not be exceeded during the period of extended operation, and there is sufficient margin to account for any unanticipated occurrence of the loadings and unloadings between 15 and 100 percent power transient.

4.3.2.12.3 UFSAR Supplement

LRA Section A3.2.1.12 provides the UFSAR supplement summarizing the metal fatigue TLAA for the Class 1 design of Class 3 feedwater control valves. The staff reviewed LRA Section A3.2.1.12, consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the reviewer confirms that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the metal fatigue TLAA for the Class 1 design of Class 3 feedwater control valves, as required by 10 CFR 54.21(d).

4.3.2.12.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the fatigue analyses for the Class 1 design of Class 3 feedwater control valves remain valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.3 ASME Code Section III Subsection NG Fatigue Analysis of Reactor Pressure Vessel Internals

4.3.3.1 Summary of Technical Information in the Application

LRA Section 4.3.3 describes the applicant's metal fatigue TLAA for the RPV internals. The applicant stated that the RVIs support the core, maintain fuel alignment, limit fuel assembly movement, maintain alignment between fuel assemblies and CRDMs, direct coolant flow past the fuel elements, direct coolant flow to the RPV head, provide gamma and neutron shielding, and guide the incore instrumentation. The applicant also stated that the design and construction of core support structures meet ASME Code, Section III, Subsection NG, in full, and other internals are designed and constructed to ensure that their effects on the core support structures remain within the core support structure limits.

The applicant stated that the licensing basis does not describe any time-limited effects for a licensed operating period associated with flow-induced vibration for the RVIs; therefore, there are no TLAAs, in accordance with 10 CFR 54.3(a), Criteria 2 and 3.

The applicant dispositioned the TLAAs for its RVIs in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the RVIs will be adequately managed by the Metal Fatigue of Reactor Coolant Pressure Boundary Program for the period of extended operation.

4.3.3.1 Staff Evaluation

The staff reviewed LRA Section 4.3.3, as amended by letter dated November 21, 2011, and the metal fatigue TLAAs for the RVIs to confirm, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed for the period of extended operation.

The staff reviewed the applicant's metal fatigue TLAA for RVIs and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with the review procedures in SRP-LR Section 4.3.3.1.1.3. These procedures state that the reviewer should confirm the appropriateness of the applicant's program for monitoring and tracking the number of critical thermal and pressure transients for the selected RCS components. The SRP-LR further states that the reviewer should ensure that the applicant's program contains the same program elements that the staff evaluated and relied upon in approving the corresponding generic program in the GALL Report.

The staff's review of the applicant's claim—that its licensing basis does not describe any time-limited effects for a licensed operating period associated with flow-induced vibration for the RVIs and that there are no TLAAs, in accordance with 10 CFR 54.3(a), Criteria 2 and 3—is documented in SER Section 4.1.2.1.2.6.

The staff noted that Westinghouse evaluated the Unit 1 and 2 RVIs for the effect of the 1.4 percent uprating and replacement steam generators. The applicant provided its fatigue usage factors, which resulted in meeting the ASME Code allowable value, in LRA Table 4.3-7. The staff noted that LRA Table 4.3-7 provides the CUF values for the RVI components, which are all less than the ASME Code design limit of 1.0. For the "baffle-former assembly," the limiting 40-Year CUF value for Units 1 and 2 is "$< 1_{(test)}$ [i.e., less than 1.0 as verified by testing]."

The metal fatigue TLAA for the RVI components, which include the "baffle-former assembly," was dispositioned in accordance with 10 CFR 54.21(c)(1)(iii), that effects of fatigue will be managed for the period of extended operation with the Metal Fatigue of Reactor Coolant Pressure Boundary Program. However, the applicant did not describe the details of the test that was performed to determine that the CUF for the "baffle-former assembly" to be less than 1.0; therefore, it is not clear how the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program will manage fatigue of the "baffle-former assembly." By letter dated

September 22, 2011, the staff issued RAI 4.3-17 requesting that the applicant describe how the CUF for the “baffle-former assembly” for Unit 1 and 2 were shown to be less than 1.0 by testing and to identify the sections of the applicable design codes that were used for the fatigue testing. In addition, the staff requested that the applicant describe and justify how the Metal Fatigue of Reactor Coolant Pressure Boundary Program will manage cumulative fatigue damage of the “baffle-former assembly,” since the CUF was shown to be less than 1.0 by testing.

In its response dated November 21, 2011, the applicant stated that a test was conducted in accordance with ASME Code Section III Appendix II, Article II-1221, in an arrangement that models the baffle-former-barrel assembly of the top two formers for a width of three baffle-former bolts. The applicant explained that the test was conducted by cyclically displacing the baffle relative to the barrel to the thermal displacement values, and an inspection was done to determine the baffle-former and barrel-former gaps after the test. The applicant stated that all bolts were deemed acceptable and survived cyclical deflection without exhibiting a significant loss of preload or any other characteristic of fatigue failure and that the fatigue test data envelop the number of cycles and the severity of the transients required by the design specification.

The applicant also stated that the fatigue tests were used in lieu of a fatigue analysis; therefore, no CUF existed for these components. The staff noted that ASME Code Section III, Subsection NG-3200, allows the use of fatigue testing in accordance with Appendix II, Article II-1200. Furthermore, Article II-1221 pointed to the provisions in Article II-1500 that require the cyclic testing performed would exceed the cycles and magnitude of the design transients. Thus, the staff found that maintaining those components within specified numbers of design transients and their severities as defined in the design specifications will ensure the tests remain valid. The staff noted that the applicant’s Metal Fatigue of Reactor Coolant Pressure Boundary Program ensures that the number and severity of transients actually experienced during the period of extended operation will remain below the assumed number in the design specification or that corrective actions will be taken. The staff’s evaluation of the Metal Fatigue of Reactor Coolant Pressure Boundary Program is documented in SER Section 3.0.3.2.28.

The staff finds the applicant’s response acceptable because the baffle-former assemblies were fatigue tested, in accordance with ASME Code Section III, Subsection NG, and Appendix II, which envelop the transients specified in the design specification. Additionally, the applicant’s Metal Fatigue of Reactor Coolant Pressure Boundary Program ensures that the number and severity of transients actually experienced will not exceed the assumptions made in order to qualify this component for fatigue. The staff’s concern described in RAI 4.3-17 is resolved.

LRA Sections 4.3.3 and A3.2.2 state that fatigue usage factors for the RVIs do not depend on effects that are time-dependent at steady-state conditions but depend only on effects of normal, upset, and emergency transient events. Furthermore, the Metal Fatigue of Reactor Coolant Pressure Boundary Program ensures that the numbers of transients actually experienced during the period of extended operation will remain below the assumed number. However, LRA Section 4.3.1.1 states that the ASME Code Section III does not require inclusion of emergency or faulted conditions in fatigue evaluations; therefore, the Metal Fatigue of Reactor Coolant Pressure Boundary Program does not monitor emergency or faulted conditions. The staff reviewed UFSAR Section 3.9.1.1.8 and noted that the small LOCA, small steam line break, and complete loss of flow system transients are considered emergency conditions but are not in LRA Table 4.3-2. By letter dated September 22, 2011, the staff issued RAI 4.3-9, asking the applicant to clarify whether emergency conditions are included into the fatigue analyses of RVI components. If so, justify whether or not the Metal Fatigue of Reactor Coolant Pressure Boundary Program monitors emergency transients. RAI 4.3-9 also requested the same information for ASME Code Section III Class 1 piping and nozzles; the evaluation for these components is documented in SER Section 4.3.2.7.2.

In its response dated November 21, 2011, the applicant stated that an editorial error was made in LRA Section 4.3.3 and LRA Appendix A3.3.2. The applicant revised these two sections to remove the discussion of emergency transients for the RVIs. The staff noted that the exclusion of emergency and faulted conditions from the calculation of CUFs is consistent with ASME Code Section III, Subsection NG, for the design of core support structures. The staff finds the applicant’s response acceptable because the applicant clarified that its design of the core support structures did not include emergency conditions, consistent with ASME Code Section III, Subsection NG. The staff’s concern described in RAI 4.3-9 related to RVIs is resolved.

In the staff’s safety evaluation (SE) dated April 12, 2002 (ADAMS Accession No. ML021130083), which approved a 1.4 percent increase in the reactor core thermal power level from 3,800 MWt to 3,853 MWt for Units 1 and 2, the staff concluded that the resulting stresses and fatigue factors from the 1.4 percent uprating upon the RVIs are within the allowable range (or limits) of the original analysis of record. The staff noted that the SE’s approval of the 1.4 percent power uprate was effective after the replacement of the Model 94 steam generators, which occurred in 2000 and 2002, for Units 1 and 2, respectively. The staff finds it appropriate that the applicant has considered the 1.4 percent uprated conditions and replacement steam generators and their effects on the stresses and fatigue factors for the RVI components.

The staff noted that as long as the number of transients that occurs for each unit remains bounded by the 40-year number of cycles assumed by the analysis, the design-basis fatigue evaluation remains valid. The staff noted that the applicant’s Metal Fatigue of Reactor Coolant Pressure Boundary Program ensures that the number of transients actually experienced during the period of extended operation will remain below the assumed number or that corrective actions will be taken. The staff’s evaluation of the Metal Fatigue of Reactor Coolant Pressure Boundary Program is documented in SER Section 3.0.3.2.28.

The staff finds that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the RVI components will be adequately managed for the period of extended operation. The staff also finds that the TLAA meets the acceptance criteria in SRP-LR Section 4.3.2.1.1.3 because the applicant’s Metal Fatigue of Reactor Coolant Pressure Boundary Program monitors and tracks the number of design basis transients that will occur through the period of extended operation and includes action limits and corrective actions that will ensure that the Code design limit of 1.0 will not be exceeded during the period of extended operation. Additionally, the use of the applicant’s program is consistent with the recommendations of GALL Report AMP X.M1.

4.3.3.2 UFSAR Supplement

LRA Section A3.2.2, as amended by letter dated November 21, 2011, provides the UFSAR supplement summarizing the metal fatigue TLAA for the RVI components. The staff reviewed LRA Section A3.2.2, consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the reviewer confirms that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the metal fatigue TLAA for the RVI components, as required by 10 CFR 54.21(d).

4.3.3.3 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the RVI components will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the metal fatigue TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.4 Effects of Reactor Coolant System Environment on Fatigue Life of Piping and Components (Generic Safety Issue 190)

4.3.4.1 Summary of Technical Information in the Application

LRA Section 4.3.4 describes the applicant's evaluation of the effects of reactor coolant environment on component fatigue life for the period of extended operation. The applicant assessed the environmental effects on fatigue at the six sample locations identified by NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," for newer vintage Westinghouse plants.

Three of the NUREG/CR-6260 sample locations in Table 4.3-8 have a 60-year EAF CUF below 1.0, when multiplied by the maximum applicable environmental adjustment factor (F_{en}) for the material, 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. The remaining NUREG/CR-6260 locations have been evaluated using ASME Code Section III, NB-3200, methods to reduce the EAF CUF values. The methods used to reduce the EAF CUF values include the following:

- recalculating the CUF with a more accurate fatigue analysis
- using projected values of the accumulated number of transient events, instead of using the 40-year number of events
- calculating an average F_{en} using strain-rate dependent F_{en} values for load set pairs significant to fatigue; and using the maximum F_{en} for load set pairs not significant to fatigue

The removal of conservatism resulted in the accumulator safety injection nozzle and RHR inlet nozzle 60-year EAF CUFs reducing to below 1.0.

The applicant stated that the EAF CUFs for the hot leg surge nozzle and charging nozzles are projected to exceed 1.0 within 60 years of operation. Corrective action for these locations will be required under the Metal Fatigue of Reactor Pressure Boundary Program in LRA Section B3.1 when the cycle-based fatigue (CBF) results, including the effects of the reactor coolant environment, indicate that a fatigue based action limit has been reached.

The applicant dispositioned the EAF evaluations for all NUREG/CR-6260 locations in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of reactor coolant environment on fatigue usage will be adequately managed for the period of extended operation.

4.3.4.2 Staff Evaluation

The staff noted that the applicant addressed the effects of the reactor coolant environment on component fatigue life, consistent with the guidance in the SRP-LR and the staff's recommendations for resolving Generic Safety Issue No. 190 (GSI-190), dated December 26, 1999. The staff also noted that, consistent with Commission Order No. CLI-10-17, dated July 8, 2010 (ADAMS Accession No. ML101890775), the evaluations associated with the effects of the reactor coolant environment on component fatigue life are not TLAAs in accordance with the definition of 10 CFR 54.3(a) because these evaluations are not in the applicant's CLB. Nevertheless, the applicant has credited its Metal Fatigue of Reactor Coolant Pressure Boundary Program to manage the effects of reactor coolant environment on component fatigue life. Therefore, the staff reviewed LRA Section 4.3.4 and the evaluations for EAF to confirm, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of reactor coolant environment on component fatigue life will be adequately managed for the period of extended operation.

The staff reviewed the applicant's EAF evaluations, as presented in the LRA and the corresponding disposition, consistent with the review procedures in SRP-LR Section 4.3.3.1.3, which state that the reviewer should confirm that the applicant has addressed the effects of the coolant environment on component fatigue life as AMPs are formulated in support of license renewal. This sample of critical components with high-fatigue usage locations should include the locations identified in NUREG/CR-6260, as a minimum, as well as any other alternatives based on plant configuration.

The staff noted that the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program includes an enhancement to develop fatigue usage calculations that consider the effects of the reactor water environment for a set of sample RCS components. This sample set will include the locations identified in NUREG/CR-6260 and additional plant-specific component locations in the RCPB if they are found to be more limiting than those considered in NUREG/CR-6260. The staff's review of this enhancement is documented in SER Section 3.0.3.2.28.

The staff noted that LRA Table 4.3-8 contains 10 plant-specific locations, which are based on the six generic components identified in NUREG/CR-6260. LRA Table 4.3-8 also contains the 40-year CUF, the 40-year EAF CUF, and the 60-year EAF CUF for these 10 plant-specific locations. During its audit, the staff noted in documentation onsite that the CUF and EAF CUF values for charging system nozzles (normal line and alternate line) and hot leg surge nozzle were different from those in LRA Table 4.3-8. By letter dated September 22, 2011, the staff issued RAI 4.3-6, requesting that the applicant revise LRA Table 4.3-8 to provide the correct CUF and EAF CUF values for the hot leg surge nozzle and charging system nozzles. The applicant was also asked to confirm that the remaining information in LRA Table 4.3-8 is accurate.

In its response dated November 21, 2011, the applicant stated that LRA Table 4.3-8 was revised to provide correct values for the hot leg surge nozzle and charging system nozzles that are consistent with the basis documents. The applicant confirmed that no other changes were identified after reviewing LRA Table 4.3-8. The staff noted that the 60-year design EAF values for these components are currently calculated to exceed 1.0; however, the applicant is managing the environmental effects on fatigue life with its Metal Fatigue of Reactor Coolant Pressure Boundary Program. Therefore, the applicant's program would manage the accumulated fatigue usage of these components to ensure that the actual fatigue usage for the component remains less than the ASME Code design limit of 1.0 during the period of extended operation; otherwise, corrective actions would be taken in accordance with its AMP.

The staff finds the applicant's response acceptable because the applicant revised values in LRA Table 4.3-8 to be consistent with its basis documents, and it is managing the effects of reactor coolant environment on fatigue life for all components in LRA Table 4.3-8 with its Metal Fatigue of Reactor Coolant Pressure Boundary Program during the period of extended operation. The staff's concern described in RAI 4.3-6 is resolved.

The staff noted that LRA Section 4.3.4 describes three methods that were used to reduce the EAF CUF values: (1) recalculating the CUF with a more accurate fatigue analysis; (2) using projected values of the accumulated number of transient events; and (3) calculating an average F_{en} using a strain-rate dependent method for load set pairs significant to fatigue and using the maximum F_{en} for load set pairs not significant to fatigue. Based on the information in the LRA, the staff was not able to determine what constituted a "more accurate fatigue analysis," how it was performed, and what conservatism was removed to obtain the reduced EAF CUF values. The staff also could not identify the locations in LRA Table 4.3-8 that used these three methods to reduce EAF CUF values.

By letter dated September 22, 2011, the staff issued RAI 4.3-7, requesting that the applicant identify the components and the associated methods described above that were used to reduce the EAF CUF values. Furthermore, the applicant was also asked to describe and justify the techniques used in performing the "more accurate fatigue analysis" and explain how any conservatism was removed to reduce the EAF CUF.

In its response dated November 21, 2011, the applicant stated that the hot leg surge nozzle, the normal and alternate charging nozzles, the RHR inlet nozzle, and the accumulator safety injection nozzle locations in LRA Table 4.3-8 were evaluated with "more accurate fatigue analyses." The applicant clarified that these evaluations were performed using the ASME Code Section III, NB-3200, methods versus the NB-3600 methods from the original Code calculations. The staff noted that typically the use of NB-3200 methods results in a lower CUF value when compared to the use of the NB-3600 methods that is simpler but more conservative. The staff also noted that these analyses were re-evaluated by using the guidance from Section 4.3 of NUREG/CR-6260, which provided an example of changes to fatigue requirements from the ASME Code edition of record for the design basis calculations to later Code editions. The staff also noted that 10 CFR 50.55a provides the requirements of ASME Code Section III and the endorsement of the Code editions that are acceptable to use.

The applicant also stated that EAF CUFs of the hot leg surge nozzle and the normal and alternate charging nozzles were calculated using the 60-year cycle projections. The staff finds the use of 60-year projections to re-evaluate the EAF CUF reasonable because it provides a more realistic CUF for 60-years of operation, including environmental effects, based on the actual plant operating practices at the applicant's site. The staff noted that there is not an issue with the use of 60-year projections for EAF CUFs because the Metal Fatigue of Reactor Coolant Pressure Boundary Program manages accumulated fatigue usage of these components to ensure that the design limit of 1.0 is not exceeded during the period of extended operation. Furthermore, the program includes corrective actions if this design limit is approached. In addition, the applicant stated that NUREG-5704, "Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels," was used calculate the F_{en} factor for stainless steel for the hot leg surge nozzle; the normal and alternate charging nozzles; and the accumulator safety injection nozzles. The staff finds the use of the formulae in NUREG-5704 to calculate the F_{en} factor, which is based on the plant-specific information of the dissolved oxygen level, strain-rate, and temperature for stainless steel components, acceptable because it is consistent with recommendations of GALL Report AMP X.M1 for methods to address the effects of reactor coolant environment on component fatigue life.

The staff finds the applicant's response acceptable because the refined analyses were performed with staff-accepted methodology in the ASME Code, Section III, as endorsed by 10 CFR 50.55a; with the 60-year projections that are based on actual plant operating practices; and in accordance with staff-accepted guidance in NUREG/CR-6260 and NUREG/CR-5704. The staff's concern described in RAI 4.3-7 is resolved.

The staff noted that LRA Table 4.3-8 provides the 60-year EAF CUF of 11.3856 for the hot leg surge nozzle (safe end) and 2.3378 for the charging system nozzles (normal and alternate line). LRA Table 4.3-1 indicates that the stainless steel hot leg surge nozzle and charging system nozzles will be monitored by the Metal Fatigue of Reactor Coolant Pressure Boundary Program with the CBF monitoring method. In the closure of GSI-190, the staff determined that the risk from fatigue failure of the primary coolant pressure boundary components is very small for a plant life of 40 years. It was not clear to the staff how the applicant will manage metal fatigue with its Metal Fatigue of Reactor Coolant Pressure Boundary Program during the period of extended operation since conservatism has already been removed to calculate the 60-year EAF CUF for these locations in which the values still exceed the ASME Code design limit of 1.0.

By letter dated September 22, 2011, the staff issued RAI 4.3-10, requesting that the applicant describe how the Metal Fatigue of Reactor Coolant Pressure Boundary Program will manage metal fatigue and consider environmental effects for these components for the period of extended operation, considering that conservatism has already been removed to obtain 60-year EAF CUF values

In its response dated November 21, 2011, the applicant stated that the normal and alternate charging nozzles' EAF CUF is based on the transient severity and the number projected for 60 years. The applicant stated that, by using the current cycle count, the CBF algorithm results in a current EAF CUF of 0.79. Therefore, the charging nozzles will continue to be managed using CBF, and additional corrective actions can be taken when the actual EAF CUF usage approaches 1.0. The applicant also stated that such corrective actions include additional analyses, repair, replacement or implementation of stress based fatigue monitoring consistent with Regulatory Issue Summary 2008-30, "Fatigue Analysis of Nuclear Power Plant Components."

In addition, the applicant stated that the design EAF CUF value is greater than 1.0 using the current cycle count for the hot leg surge nozzle. The staff noted that corrective actions, which include reanalysis, repair, or replacement, will be taken, consistent with the applicant's Metal Fatigue for Reactor Pressure Boundary Program and UFSAR supplement in LRA Appendix A. The staff reviewed SECY-95-245, "Completion of the Fatigue Action Plan," September 25, 1995, (ADAMS Accession No. ML031480210) and noted that the basis in the Office of Nuclear Regulatory Research study did not support and justify the action of requiring a backfit of the environmental fatigue data to operating plants and concluded that the EAF issues in the Fatigue Action Plan should be evaluated for any proposed extended period of operation for license renewal. Based on the conclusions documented in SECY-95-245, the staff finds it appropriate that the applicant will take corrective actions in accordance with its Metal Fatigue for Reactor Pressure Boundary Program. The staff finds the applicant's response acceptable because the applicant is managing EAF during the period of extended operation, as recommended in

SECY-95-245, the applicant is using its Metal Fatigue for Reactor Pressure Boundary Program consistent with the recommendations in GALL Report AMP X.M1. This program will take corrective actions prior to entering the period of extended operation, consistent with SECY-95-245, to repair, replace, or reanalyze the EAF CUF such that the Code design limit of 1.0 will not be exceeded. The staff's concern described in RAI 4.3-10 is resolved.

LRA Section 4.3.4 states that the RPV wall transition, RPV inlet nozzle, and RPV outlet nozzle have a 60-year EAF CUF less than 1.0 when multiplied by the maximum applicable F_{en} value for low-alloy steels. For these low-alloy steel components, LRA Table 4.3-8 provides a F_{en} value of 2.455, which was determined based on NUREG/CR6583. The staff noted that based on the formulation in NUREG/CR-6583, the F_{en} value depends on sulfur content, temperature, dissolved oxygen, and strain-rate at the applicant's site. It was not clear to the staff what assumptions were used by the applicant in determining the F_{en} values for the low-alloy steel components.

By letter dated September 22, 2011, the staff issued RAI 4.3-19 requesting that the applicant clarify how the F_{en} values for the low-alloy steel components were determined and justify any assumptions on the parameters, such as sulfur content, temperature, dissolved oxygen, and strain rate, which were used. Furthermore, the applicant was asked to confirm that the dissolved oxygen remained less than 0.05 parts per million (ppm) since initial plant operation. The applicant was also asked to justify that the dissolved oxygen content will remain less than 0.05 ppm during the period of extended operation, such that the F_{en} values would remain bounding for the conditions at the plant for the low-alloy steel components.

In its response dated November 21, 2011, the applicant stated strain-rate and sulfur content were assumed to be worst case for the F_{en} value for low-alloy steel components, which the staff finds to be a conservative assumption. The applicant also stated that the dissolved oxygen level was assumed to be less than 0.05 ppm, which corresponds to a low-oxygen environment. The staff noted that based on equations in NUREG/CR-6583, the dissolved oxygen level only affects the F_{en} calculation when the RCS temperature is greater than 150 °C (302 °F). The applicant stated that the assumption for dissolved oxygen is consistent with its Primary Water Chemistry Program that maintains the dissolved oxygen at less than 0.005 ppm when the temperature is greater than 121 °C (250 °F). The applicant reviewed its primary water chemistry history identified only one occurrence of short duration (approximately 2 hours) where the RCS dissolved oxygen exceeded 0.05 ppm while RCS temperature was greater than 121 °C (250 °F). The staff found that the 2-hour period of time when the dissolved oxygen levels exceeded 0.05 ppm while RCS temperature was greater than 121 °C (250 °F) does not have a significant impact on the overall F_{en} value because the time duration is negligible in comparison to the total amount of time the plant has operated. The applicant also stated that its Primary Chemistry Program maintains the dissolved oxygen at less than 0.005 ppm when the RCS temperature is greater than 121 °C (250 °F), and this program will be continued through the extended period of operation.

The staff finds the applicant's response acceptable for the following reasons:

- The applicant provided adequate justification for the assumptions made in determining F_{en} factors, for low-alloy steel components, which the staff confirmed was bounding based on the operating parameters of these components.
- The applicant confirmed that it has historically maintained dissolved oxygen content to less than 0.05 ppm, except as justified above.

- The applicant will continue to maintain its primary water chemistry and dissolved oxygen content less than 0.05 ppm during the period of extended operation.

The staff's concern described in RAI 4.3-19 is resolved.

Based on its review, the staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of reactor coolant environment on component fatigue life will be adequately managed for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.3.2.1.3 because the applicant has demonstrated that the impact of the reactor coolant environment on critical components has been adequately addressed and will be managed by the Metal Fatigue for Reactor Pressure Boundary Program. Therefore, the applicant's EAF evaluations will remain valid, and the ASME Code limit of 1.0 will not be exceeded during the period of extended operation or corrective actions will be taken.

4.3.4.3 UFSAR Supplement

LRA Section A3.2.3 provides the UFSAR supplement summarizing the effects of the reactor coolant environment on fatigue life of piping and components. The staff reviewed LRA Section A3.2.3, consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that reviewer confirms that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the effects of reactor coolant environment on fatigue life.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the effects of reactor coolant environment on component fatigue life, as required by 10 CFR 54.21(d).

4.3.4.4 Conclusion

On the basis of its review, the staff concludes that, consistent with Commission Order No. CLI-10-17, the applicant's evaluations on the effects of the reactor coolant environment on component fatigue life is not a TLAA, as defined by 10 CFR 54.3(a). However, the staff also concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of reactor coolant environment on component fatigue life will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the evaluation, as required by 10 CFR 54.21(d).

4.3.5 Assumed Thermal Cycle Count for Allowable Secondary Stress Range Reduction Factor in ANSI B31.1 and ASME Code Section III Class 2 and 3 Piping

4.3.5.1 Summary of Technical Information in the Application

LRA Section 4.3.5 describes the applicant's allowable secondary stress range reduction factor TLAAs for ANSI B31.1 and ASME Code Section III Class 2 and 3 piping. The applicant stated that its non-Class 1 piping was based on the design codes of the 1974 edition, including winter 1975 addenda, of the ASME Code Section III Class 2 and Class 3 and the 1973 edition, including winter 1975 addenda, of the ANSI B31.1. Both codes require a stress range reduction factor to the allowable stress range if the number of equivalent full temperature cycles exceeds 7,000. The applicant compared the 7,000-cycle limit against its 60-year projections for its thermal transients, listed in the LRA Table 4.3-2, as applicable to these non-Class 1 components and determined that the 7,000-cycles limit will not be exceeded. The applicant dispositioned the piping analyses with allowable secondary stress range reduction factor in accordance with 10 CFR 54.21(c)(1)(i), that the analyses (stress range reduction factor) for ANSI B31.1 and ASME Code Section III Class 2 and 3 piping remain valid for the period of extended operation.

4.3.5.2 Staff Evaluation

The staff reviewed LRA Section 4.3.5 to confirm, pursuant to TLAA disposition criteria of 10 CFR 54.21(c)(1)(i), that the fatigue analyses for ANSI B31.1 and ASME Code Section III Class 2 and 3 piping remain valid for the period of extended operation.

The staff reviewed the applicant’s TLAA and its corresponding disposition, consistent with the review procedures in SRP-LR Section 4.3.3.1.2.1. The SRP-LR states that the staff reviews the relevant information in the TLAA, operating plant transient history, design basis, and CLB (including TS cycle counting requirements) to confirm that the maximum allowable stress range values for the existing fatigue analysis remain valid for the period of extended operation. It also confirms that the allowable limit for full thermal range transients will not be exceeded during the period of extended operation.

The staff reviewed the applicable design code requirements in UFSAR Tables 3.2.A-1 and 3.2.B-1 for components that are within the scope of license renewal and noted that the TLAAs for non-Class 1 components are based on the criteria in the ANSI B31.1 and in ASME Code Section III. These design codes required an allowable stress range reduction only if the number of full thermal cycles exceeds the limit of 7,000.

The staff reviewed the applicant’s AMR results in the associated LRA Table 2s in LRA Sections 3.2, 3.3 and 3.4, and noted that the applicant did not include applicable AMR items for the TLAAs associated with fatigue of non-Class 1 piping. It is not clear to the staff why the components analyzed for cumulative fatigue damage, as discussed in LRA Section 4.3.5, are not included as AMR line items in LRA Sections 3.2, 3.3, and 3.4.

By letter dated September 22, 2011, the staff issued RAI 4.3-18, requesting that the applicant revise the applicable LRA Table 2s in LRA Sections 3.2, 3.3, and 3.4 to include the AMR items that address cumulative fatigue damage for non-Class 1 piping. In its response dated November 21, 2011, the applicant stated that AMR items were inadvertently omitted from the LRA. Therefore, the following LRA tables will be revised to include the omitted AMR items:

- LRA Table 3.3.2-8, Primary Process Sampling
- LRA Table 3.3.2-19, Chemical and Volume Control
- LRA Table 3.3.2-20, Standby Diesel Generator
- LRA Table 3.3.2-21, Nonsafety-related Diesel Generator
- LRA Table 3.3.2-22, Liquid Waste Processing
- LRA Table 3.4.2-1, Main Steam
- LRA Table 3.4.2-2, Auxiliary Steam System and Boilers
- LRA Table 3.4.2-5, Steam Generator Blowdown
- LRA Table 3.4.2-6, Auxiliary Feedwater System

The staff confirmed that the applicant amended the aforementioned LRA tables to include additional AMR items with an aging effect of cumulative fatigue damage. The staff's review of these additional AMR items are documented in SER Sections 3.3.2.2.1 and 3.4.2.2.1.

The staff finds the applicant's response acceptable because the LRA was amended to include those systems, structures, and components subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff's concern described in RAI 4.3-18 is resolved.

The staff also reviewed the projected number of occurrences for plant transients for 60-years of operation, as given in LRA Table 4.3-2, to ensure the full thermal range transient cycle limit of 7,000 will not be exceeded. The staff's review of the applicant's 60-year projection methodology is documented in SER Section 4.3.1.2.

Based on its review, the staff confirmed that the full thermal range transient cycle limit of 7,000—used in the applicant's design basis fatigue evaluations associated with the ANSI B31.1 and ASME Code Section III Class 2 and 3 piping—will not be exceeded during the extended period of operation. Therefore, the maximum allowable stress range values for the existing analyses remain valid.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the TLAAs of ANSI B31.1 and ASME Code Section III Class 2 and 3 piping fatigue analyses remain valid for the period of extended operation. Additionally, the applicant meets the acceptance criteria in SRP-LR Section 4.3.2.1.2.1 because the projected total number of full thermal range transients over the period of extended operation for ANSI B31.1 and ASME Code Section III Class 2 and 3 piping does not exceed the 7,000-cycle limit.

4.3.5.3 UFSAR Supplement

LRA Section A3.2.4 provides the UFSAR supplement summarizing the TLAA for ANSI B31.1 and ASME Code Section III Class 2 and 3 piping fatigue analyses. The staff reviewed LRA Section A3.2.4, consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the reviewer confirms that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the TLAA.

Based on its review of the UFSAR supplement, the staff finds that the supplement meets the acceptance criteria in SRP-LR Section 4.3.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA of ANSI B31.1 and ASME Code Section III Class 2 and 3 piping fatigue analyses, as required by 10 CFR 54.21(d).

4.3.5.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the fatigue analyses of ANSI B31.1 and ASME Code Section III Class 2 and 3 piping remain valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an adequate summary description of the evaluated TLAAs, as required by 10 CFR 54.21(d).

4.3.6 ASME Code Section III Fatigue Analysis of Metal Bellows and Expansion Joints

4.3.6.1 Summary of Technical Information in the Application

LRA Section 4.3.6 describes the applicant's TLAAs for the metal bellows and expansion joints, except for the fuel transfer bellows that are discussed in LRA Section 4.6.2. The applicant stated that a search of its CLB discovered design requirements of the diesel generator cooling water bellows. UFSAR Section 9.5.5, "Diesel Generator Cooling Water System," identifies the design of the diesel generator cooling water bellows as ASME Code Section III, Class 3. In addition, the metal expansion joints design specification requires that these expansion joints be designed in accordance with Section ND of the ASME Code Section III 1977 edition, including summer 1977 addenda, and have a minimum design life of 40 years. The applicant stated that the fatigue analyses for the metal expansion joints confirm the 40-year design requirement for the diesel generator cooling water expansion joints by satisfying ASME Code Section III, Subsection ND-3649.4(d), which limits the component's lifetime cyclical loading.

The applicant dispositioned the TLAA for all but seven of the diesel generator cooling water expansion joints in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation. The applicant also dispositioned the TLAA for the seven diesel generator cooling water expansion joints that are projected to exceed the analyzed number of cycles during the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii) and committed (Commitment No. 32) to replace these expansion joints prior to the period of extended operation. The applicant stated that the analyses for the replacement expansion joints will include the period of extended operation.

4.3.6.2 Staff Evaluation

The staff reviewed LRA Section 4.3.6 and the TLAAs for the diesel generator cooling water expansion joints to confirm, pursuant to 10 CFR 54.21(c)(1)(i), that the analysis remains valid for the period of extended operation and pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging will be adequately managed for the period of extended operation.

The staff reviewed the applicant's TLAA for all but seven of the diesel generator cooling water expansion joints and the corresponding disposition of 10 CFR 54.21(c)(1)(i), consistent with the review procedures in SRP-LR Section 4.7.3.1.1. These procedures state that justification provided by the applicant is reviewed to confirm that the existing analyses are valid and are bounding for the period of extended operation.

The staff also reviewed the applicant's TLAA for the seven diesel generator cooling water expansion joints that are projected to exceed the analyzed number of cycles during the period of extended operation and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with the review procedures in SRP-LR Section 4.7.3.1.3. These procedures state that the reviewer confirms that the effects of aging on the intended function(s) are adequately managed consistent with the CLB for the period of extended operation.

The applicant stated that the analyzed numbers of cycles for all but seven of the diesel generator cooling water expansion joints are greater than the specified numbers of cycles extrapolated to 60 years; therefore, the analyses are valid for these bellows through the period of extended operation. However, the staff noted that the applicant did not provide the number of analyzed cycles and the specified numbers of cycles extrapolated to 60 years to justify the disposition in accordance with 10 CFR 54.21(c)(1)(i) for all but seven of the diesel generator cooling water expansion joints. Also, during its review the staff noted that LRA Table 3.3.2-4 provides an AMR item for nickel-alloy expansion joints exposed to raw water and subject to cumulative fatigue damage in the essential cooling water system and essential cooling water wash system, which are managed by a TLAA. However, it was not clear which specific TLAA is being credited to manage cumulative fatigue damage for this particular AMR item. By letter dated September 22, 2011, the staff issued RAI 4.3-4, requesting that the applicant provide the analyzed cycles and the “specified number of cycles” extrapolated to 60 years for these diesel generator cooling water expansion joints and justify the associated disposition of this TLAA. In addition, the staff asked the applicant to clarify the fatigue TLAA that is being credited to manage cumulative fatigue damage for the nickel-alloy expansion joints identified by the AMR item in LRA Table 3.3.2-4.

In its response dated November 21, 2011, the applicant provided a table that lists the design analyzed and the design specified numbers of cycles for its metal bellows and expansion joints with an ASME Code Section III fatigue analysis. The staff noted that the applicant extrapolated the specified cycles to 60 years by multiplying it by 1.5, and if the number of design analyzed cycles is greater than the design specified number of cycles projected to 60 years, then the analysis is valid for the period of extended operation. The staff finds the use of this 1.5 factor reasonable for the specified cycles because it provides the ratio of 60 years to 40 years, and the resulting estimated 60-year cycles provides a gauge of how much margin is available before the analyzed cycles are reached. The staff noted that for the seven diesel generator expansion joints in which the design specified cycles exceeded the design analyzed cycles, the applicant will replace them prior to the period of extended operation, as discussed below. Other than these seven expansion joints, the design analyzed number of cycles is greater than the number of cycles specified for 40 years and expected for 60 years of operation.

In addition, the applicant clarified that the nickel-alloy expansion joints identified in LRA Table 3.3.2-4 are the ECW pump expansion joints, 3R281(2)NJX101(201)A/B/C. The applicant revised LRA Section 4.3.6 and Appendix A3.2.5 to include the ECW pump expansion joints identified by the AMR item in LRA Table 3.3.2-4.

Based on its review, the staff finds the applicant’s response acceptable because the applicant demonstrated that its specified cycles for 60 years does not exceed the number of analyzed cycles for the analysis of the expansion joints and metal bellows that were dispositioned in accordance with 10 CFR 54.21(c)(1)(i). The staff’s concern described in RAI 4.3-4 is resolved.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses for all but seven of the diesel generator cooling water expansion joints, including the ECW pump expansion joints, remain valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.7.2.1 because the applicant demonstrated that the analyzed number of cycles for 40 years will not be exceeded during the period of extended operation.

The applicant committed (Commitment No. 32) to replace the seven diesel generator cooling water expansion joints that are projected to exceed the analyzed number of cycles during the period of extended operation. Commitment No. 32 also states that the analyses for the replacement expansion joints will include the period of extended operation. The staff noted the current expansion joints are designed in accordance with Section ND of the ASME Code Section III 1977 Code, including summer 1977 addenda, and have a minimum design life of 40 years. The staff noted that the regulations at 10 CFR 50.55a specify the ASME Code requirements. Specifically, IWA-4000 of the ASME Code, Section XI provides the requirements for repair and replacement activities for ASME Code Classes 1, 2, and 3 pressure-retaining components. The staff noted that in order for the applicant to comply with its CLB, the number of cycles for these seven expansion joints cannot exceed the design limit. Furthermore, any repair or replacement activities of these seven expansion joints will be performed in accordance with the ASME Code, Section XI, which is required by 10 CFR 50.55a. The staff also confirmed in LRA Table 3.3.2-20 that the expansion joints, subject to a TLAA, have a pressure boundary intended function. Since the replacement expansion joints will be installed prior to the period of extended operation and the fatigue analysis for these replacement components will have a minimum design life of 40 years, the staff determined that the fatigue analysis for these seven replacement diesel generator cooling water expansion joints will be beyond the period of extended operation.

The staff finds that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the seven diesel generator cooling water expansion joints that are projected to exceed the analyzed number of cycles during the period of extended operation will be adequately managed for the period of extended operation. The applicant’s approach meets the acceptance criteria in SRP-LR Section 4.7.2.1 because the applicant’s compliance with its CLB for these seven diesel generator cooling water expansion joints is governed by the ASME Code, Section XI and 10 CFR 50.55a. In addition, the applicant’s Commitment No. 32—to replace these seven diesel generator cooling water expansion joints prior to the period of extended operation—provides a process for the applicant to track the completion of replacing these seven diesel generator cooling water expansion joints.

4.3.6.3 UFSAR Supplement

LRA Section A3.2.5 provides the UFSAR supplement summarizing the TLAA for the ASME Code Section III metal bellows and expansion joints. The staff reviewed LRA Section A3.2.5, consistent with the review procedures in SRP-LR Section 4.7.3.2, which state that the reviewer confirms that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the UFSAR supplement, the staff finds that it meets the acceptance criteria in SRP-LR Section 4.7.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA for the ASME Code Section III metal bellows and expansion joints, as required by 10 CFR 54.21(d).

4.3.6.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses for all but seven of the diesel generator cooling water expansion joints remain valid for the period of extended operation. The staff also concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the seven diesel generator cooling water expansion joints projected to exceed the analyzed number of cycles during the period of extended operation will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.4 <u>Environmental Qualification of Electrical Equipment</u>

The EQ requirements established by 10 CFR Part 50, Appendix A, Criterion 4, and 10 CFR 50.49 specifically require each applicant to establish a program to qualify electrical equipment so that such equipment, in its end of life, will meet its performance specifications during and following design-basis accidents. The 10 CFR 50.49 EQ Program is a TLAA for purposes of license renewal. Electrical equipment with a qualified life equal to or greater than the duration of the current operating term is covered by TLAAs. The TLAA of the EQ of electrical components includes all long-lived, passive, and active electrical and instrumentation and control (I&C) components that are important to safety and are located in a harsh environment. The harsh environment includes those areas subject to environmental effects caused by LOCAs, HELBs, and post-LOCA radiation.

As required by 10 CFR 54.21(c)(1), the applicant must provide a list of TLAAs. In addition, 10 CFR 54.21(c)(1) requires that the applicant demonstrate, for each TLAA, that the analyses remain valid for the period of extended operation, the analyses have been projected to the end of the period of extended operation, or the effects of aging on the intended functions will be adequately managed for the period of extended operation.

4.4.1 Summary of Technical Information in the Application

LRA Section 4.4 describes the applicant's TLAA for EQ of electrical equipment. The applicant stated that the scope of equipment requiring qualification is those which automatically perform, are used by operator action to perform, or whose failure could prevent the performance of:

- emergency reactor shutdown
- containment isolation
- reactor core cooling
- containment and reactor heat removal
- prevention of a significant release of radioactivity to the environment
- certain post-accident monitoring equipment

The applicant also stated that the EQ Program is consistent with the guidance of NUREG-0588, Category I, and the requirements of 10 CFR 50.49, with exemption from the EQ scope for certain low-safety significance (LSS) and non-risk significant (NRS) components.

The applicant dispositioned the EQ of Electric Equipment TLAA in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed for the period of extended operation.

4.4.2 Staff Evaluation

The staff reviewed LRA Sections 4.4 and B.3.2, EQ of Electric Equipment TLAA to confirm, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed for the period of extended operation.

The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with the review procedures in SRP-LR Section 4.4.3.1.3, which state that the applicant may reference the GALL Report in its LRA, as appropriate. The SRP-LR also states that the reviewer should confirm that the applicant has stated that the report is applicable to its plant with respect to its EQ Program.

In LRA Section 4.4, "Environmental Qualification (EQ) of Electric Components," the applicant stated that the program is consistent with the guidance of NUREG-588, Category I, and the requirements of 10 CFR 50.49, with exemption from environmental scope for certain LSS and NRS components

Part 49 of 10 CFR, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants," establishes a program for qualifying the electric equipment (e.g., safety-related electric equipment, nonsafety-related electric equipment, and certain post-accident monitoring equipment). By letters dated July 13, 1999, as supplemented October 14 and 22, 1999, January 26 and August 31, 2000, and January 15, 18, 23, March 19, May 8 and 21, 2001, (hereinafter, the submittal, Adams Accession No. ML011430090), the applicant requested an exemption from 10 CFR Part 49(b), to exclude LSS and NRS components from the scope of electrical equipment important to safety under 10 CFR 50.49(b).

The staff noted that 10 CFR 54.21(c)(2) states that a list must be provided of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based on TLAAs, as defined in 10 CFR 54.3. The applicant shall provide an evaluation that justifies the continuation of these exemptions for the period of extended operation.

The staff also noted that 10 CFR 54.4(a)(1) states:

> Plant systems, structures, and components within the scope of this part are safety-related systems, structures, and components which are those relied upon to remain functional during and following design-basis events (as defined in 10 CFR 50.49(b)(1)) to ensure the integrity of the reactor coolant pressure boundary; (and) the capability to shut down the reactor and maintain it in a safe shutdown condition; or the capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in § 50.34(a)(1), § 50.67(b)(2), or § 100.11 of this chapter, as applicable.

The applicant did not provide the plant-specific exemptions granted pursuant to 10 CFR 50.12 and, in effect, that are based on TLAAs, as defined in 10 CFR 54.3 and as applied to 10 CFR 50.49(b). Furthermore, the applicant did not provide any evaluation that justifies the continuation of this exemption for the period of extended operation. The staff is concerned that an exemption to 10 CFR 50.49(b) for electric equipment important to safety based on probabilistic risk assessment is inconsistent with the license renewal rule statement of considerations and 10 CFR Part 54.4 scoping, which uses deterministic criteria. Further, the staff is concerned that these exempted electric components are not included in the scope of license renewal; therefore, they are not subject to a TLAA or an associated AMP and, therefore, may not be capable of performing their intended function for the period of extended operation.

By letter dated September 22, 2011, the staff issued RAI 4.4-1, requesting the following from the applicant:

- provide a list of electrical and I&C system SSCs that were excluded from the scope of license renewal (10 CFR 54.4 (a)(1), (a)(2), and (a)(3)) as a result of special treatment requirements exemption of SSCs
- provide a list of electrical and I&C system SSCs that have been exempted from 10 CFR 50.49(b), including SSC replacements, subject to 10 CFR 54.4

- indicate whether the electrical and I&C system components, for which the exemption for 10 CFR 50.49 was granted, are within the scope of license renewal and, if not, provide justification for their exclusion and justify the continuation of these exemptions into period of extended operation
- describe any subsequent modifications or changes to either plant design or LSS/NRS components that revised LSS/NRS electrical and instrumentation and control component environmental conditions or qualification and, if so, describe the modifications or changes incorporated into the aging management of the LSS/NRS electrical and I&C components
- discuss how the specific management program/controls (inspection, tests, and surveillances) are adequate to provide aging management during the period of extended operation such that LSS/NRS electrical and I&C components are capable of performing their intended function under design basis conditions throughout the service life of the component

In its response dated November 21, 2011, the applicant stated the following:

- No components were excluded from the scope of license renewal as a result of special treatment requirements exemption of SSCs (10 CFR 50.69).
- There are no electrical and I&C system SSCs, including SSC replacements that have been exempted from 10 CFR 50.49 qualification requirements. The LSS and NRS EQ components are treated the same way as non-LSS and NRS EQ components with the exception that the documentation requirements for LSS and NRS components are not as stringent to that of non LSS and NRS EQ components. UFSAR Section 13.7 allows LSS and NRS components to not be qualified per 10 CFR 50.49, but, as stated above, STP has opted to maintain the qualification of the LSS and NRS components.
- The EQ electrical and I&C system components classified as LSS or NRS are within the scope of license renewal. No EQ components were excluded from the scope of license renewal as a result of special treatment requirements exemption of SSCs (10 CFR 50.69).
- Data loggers were installed in containment at selected locations to determine actual temperatures. This data was then used to determine the qualified life of EQ transmitters at those selected locations. The actual temperatures were lower than the design temperature, which provided margin for extending the qualified life. The data gathered was for extending the qualified life of selected transmitters but did not change the design criteria. Design change packages were prepared with the new qualified lives.
- The special exemption components are part of the STP EQ Program. They are treated the same way as any other EQ component with the exception that the documentation requirement is not as stringent as that of a normal EQ component. These components would still follow the replacement dates (start of qualified life (SOQL) and replacement due date (RDD)), as designated under its qualification maintenance database (QMDB).

The staff found the applicant response acceptable because the applicant will maintain the qualified life of EQ electrical components in accordance to 10 CFR 54.4 requirements, and no EQ component will be excluded from the scope of license renewal.

The staff reviewed LRA Sections 4.4 and B.3.2 and plant basis documents, and interviewed plant personnel to confirm whether the applicant provided adequate information to meet the requirement of 10 CFR 54.21(c)(1). For the electrical equipment, the applicant uses 10 CFR 54.21(c)(1)(iii) in its TLAA evaluation to demonstrate that the aging effects of EQ equipment will be adequately managed during the period of extended operation. The staff reviewed the applicant's EQ program to determine whether it will assure that the electrical and I&C components covered under this program will continue to perform their intended functions, consistent with the CLB, for the period of extended operation. Per the GALL Report, plant EQ programs that implement the requirements of 10 CFR 50.49 are considered acceptable AMPs under license renewal (10 CFR 54.21(c)(1)(iii)). GALL Report AMP X.E1, "Environmental Qualification (EQ) of Electric Components," provides a means to meet the requirements of 10 CFR 54.21(c)(1)(iii).

The staff's evaluation of the components' qualification focused on how the EQ Program manages the aging effects to meet the requirements pursuant to 10 CFR 50.49. The staff conducted an audit of the information provided in LRA Sections 4.4 and B.3.2 and program basis documents. LRA Section 4.4 discusses the component reanalysis attributes, including analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions. On the basis of its audit, the staff finds that the EQ Program, which the applicant claimed to be consistent with GALL Report AMP X.E1, "Environmental Qualification of (EQ) Electric Components," is consistent with the GALL Report. The staff further concludes that the applicant's EQ of Electrical Equipment TLAA is implemented per the requirements of 10 CFR 54.21(c)(1)(iii).

Therefore, the staff finds that the applicant's EQ Program demonstrates, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed for the period of extended operation. The applicant's EQ Program is, therefore, capable of programmatically managing the qualified life of components within the scope of the program for license renewal. The continued implementation of the EQ Program provides assurance that the aging effects will be managed and that components within the scope of the EQ Program will continue to perform their intended functions for the period of extended operation.

4.4.3 UFSAR Supplement

LRA Section A.4.4.1 provides the UFSAR supplement summarizing the EQ of Electric Equipment Program, which manages component thermal, radiation, and cyclical aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components not qualified for the current license term are to be refurbished or replaced or have their qualification extended prior to reaching the aging limits established in the evaluation. The staff reviewed LRA Section A.4.4.1, consistent with the review procedures in SRP-LR Section 4.4.3.2, which state that the reviewer confirms that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the TLAA evaluation of the environmental qualification of electric equipment. The SRP-LR also states that the reviewer confirms that the applicant has provided a UFSAR supplement with information equivalent to that in SRP-LR Table 4.4-2.

Based on its review, the staff finds that the UFSAR supplement meets the acceptance criteria in SRP-LR Section 4.4.3.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the EQ of Electric Equipment Program, which manages component thermal, radiation, and cyclical aging through the use of aging evaluation based on 10 CFR 50.49(f) qualification methods, as required by 10 CFR 54.21(d).

4.4.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions of the EQ of Electric Equipment TLAA will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the EQ of electric equipment TLAA evaluation of the period of extended operation, as required by 10 CFR 54.21(d).

4.5 Concrete Containment Tendon Prestress Analysis

4.5.1 Summary of Technical Information in the Application

LRA Section 4.5 describes the applicant's TLAA for concrete containment tendon prestress analysis. The LRA states that the containment for each unit is a prestressed concrete, hemispherical, dome-on-a-cylinder structure with steel membrane liners and a flat basemat. Post-tensioned tendons compress the concrete and permit the structure to withstand design-basis accident internal pressures. The LRA states that the Tendon Surveillance Program is used to ensure that tendons continue to maintain adequate prestress for the period of extended operation. The applicant's Tendon Surveillance Program periodically measures the prestress load on a defined sample of tendons and examines the condition of the tendons and supporting structures, materials, and components. The data collected from the program reconfirm that the expected tendon prestress loads will remain within design limits to at least the next inspection, or, if the relaxation is not acceptable, the program prescribes retensioning or other corrective measures to ensure that at no time will the average prestress in a tendon group fall below the minimum required prestress.

The LRA describes the post-tensioning system of each unit as consisting of two tendon groups. There are 96 vertical, inverted-U-shaped tendons that extend up through the basemat through the full height of the cylindrical walls and over the dome. The vertical tendons are anchored through the bottom of the basemat. There are 133 horizontal circumferential (hoop) tendons located at intervals from the basemat up to approximately the 45-degree elevation of the dome. They are anchored at three exterior buttresses, 120 degrees apart. The total tendon load is carried by a shim stack to steel bearing plates embedded in the structure.

LRA, Appendix B, Section B3.3 summarizes the TLAA AMP, "Concrete Containment Tendon Prestress" Program. The inspection program is governed by ASME Code Section XI, Subsection IWL. In accordance with 10 CFR 50.55a(g)(4)(ii), the third inservice inspection (ISI) program for ASME Code Section XI, Subsection IWL will be conducted in accordance with the requirements of the 2004 edition (no addenda). The LRA states that the program calculates current trend values for each tendon on an individual basis by regression of the full set of individual tendon lift-off data for each tendon group, consistent with the methodology presented in NRC Information Notice (IN) 99-10, "Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments," attachment 3. The LRA further states that the calculations of predicted force are consistent with NRC RG 1.35.1, "Determining Prestressing Forces for Inspection of Prestressed Concrete Containments." The current Tendon Surveillance Program uses the ASME Code Section XI, Subsection IWL acceptance criteria of 95 percent of the predicted force, in lieu of the RG 1.35.1 lower bound.

The LRA states that the surveillance calculation estimates the 40-year loss of prestressing force and lists the predicted and measured lift-off forces for individual tendons selected for surveillance. The LRA further states that the measured force trend lines, when projected past 60 years, remain above the minimum required design prestress values. The most recent regression analysis is included in the 2009, 20-year tendon surveillance report. The LRA states that the recent surveillance data for individual tendons have all fallen above the first action limit at 95 percent of the predicted force line, and the regression analysis of surveillance lift-off data has extended the trend lines for both the vertical and horizontal tendons of each unit to 100 years. Finally, the LRA states that the trend lines for horizontal and vertical tendons will remain well above their minimum required values through the period of extended operation.

The applicant dispositioned the concrete containment tendon prestress TLAA in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed for the period of extended operation.

4.5.2 Staff Evaluation

The staff reviewed LRA Section 4.5 and the concrete containment tendon prestress TLAA to confirm, pursuant to 10 CFR 54.21(c)(1)(ii), that the analyses have been projected to the end of the period of extended operation.

The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with the review procedures in SRP-LR Section 4.5.3.1.2. The staff reviewed SRP-LR Section 4.5.2.1.2 to confirm that the trend lines of the measured prestressing forces are projected to stay above the design minimum required value (MRV) for each group of post-tensioned tendons during the period of extended operation, as required by the design basis of the containment building and its post-tensioning system. The staff reviewed LRA Section 4.5 and the tendon regression analysis input data of the measured lift-off forces (LRA Table 4.5-1) to confirm that the lift-off trend lines for each tendon group are based on individual tendon lift-off forces and not average lift-off forces for the entire group, as discussed in IN 99-10. Figures 4.5-1 through 4.5-4 of LRA Section 4.5 show the trend lines for the regression analysis of the Unit 1 and Unit 2 vertical and horizontal tendon lift-off data. For all tendon groups, projected prestressing force trend lines remain above their respective MRVs through the period of extended operation.

LRA Section 4.5 states that, in accordance with 10 CFR 54.21(c)(1)(iii), the applicant credits the Concrete Containment Tendon Prestress Program to manage the loss of tendon prestress for the period of extended operation. The LRA states that the program will confirm that the average lift-off forces of the prestressing tendons remain above their MRVs through the period of extended operation. The Concrete Containment Tendon Prestress Program is described in LRA Section B3.3. The staff reviewed LRA Section B3.3 in accordance with the review procedures of SRP-LR Section 4.5.3.1.3 to confirm the applicant identified the appropriate program as described and evaluated in the GALL Report. LRA Section B3.3 states that the Concrete Containment Tendon Prestress Program is within the ASME Code Section XI Subsection IWL Program, which manages the loss of tendon prestress aging effect in the post-tensioning system. The staff's review of the Concrete Containment Tendon Prestress Program is discussed in Section 3.0.3.1.9 of this SER.

The LRA states that the containment tendon ISI program was originally in accordance with RG 1.35, "Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containment Structures," and that beginning in year 15, inspections have been in accordance with ASME Code, Section IWL. RG 1.35 states that the ISI should be performed at 1, 3 and 5 years after the initial structural integrity test (ISIT) and every 5 years thereafter. ASME Code Section IWL-2421, "Sites With Multiple Plants," states that for the containment with the first structural integrity test, examinations be performed at 1, 3, and 10 years and every 10 years thereafter. For each subsequent containment, examinations should be performed at 1, 5, and 15 years and every 10 years thereafter. The staff noted that there were no data provided in LRA Table 4.5-1 for a 3-year tendon inspection of either containment; therefore, in Part 2 of RAI B3.3-2 (by letter dated August 15, 2011), the staff requested that the applicant describe the tendon surveillance intervals for both containments. In its response dated October 10, 2011, the applicant stated that the plant was originally licensed for a containment inspection program that was in accordance with RG 1.35 (April 1979, proposed revision 3). The applicant stated that the schedule in the proposed RG 1.35 did not call for inspection at year 3, rather at year 5, and that the actual liftoff testing for Unit 1 was performed at year 5 in accordance with that schedule. The staff determined this to be inconsistent with the applicant's program basis documentation, specifically CC-5207, Revision 8, "RCB Tendon Surveillance," approved on August 12, 2004, which contains a list of tendons examined in year 3 surveillances for both units, as well as the methodology for determining the year 3 sample population. In a teleconference on January 4, 2012, the staff requested that the applicant further explain the basis for the schedule of tendon inspections and the year-3 surveillance activities found in the Tendon Surveillance Program basis documents. The applicant explained that their inspection program takes credit for Regulatory Position 1.5 in RG 1.35. Regulatory Position 1.5 states:

> [T]he liftoff force comparison [may be modified from the 1, 3 and 5 year schedule stated in Regulatory Position 1.3 to perform the second tendon surveillance lift-off test at year 5 instead of year 3] if any two containments at the same site are shown to satisfy all three of the following conditions: (a) the containments are identical in all aspects such as size, tendon system, design, materials of construction, and method of construction; (b) their ISITs were performed within two years of each other; and (c) there is no unique situation that may subject either containment to a different potential for structural or tendon deterioration.

The applicant further explained that the information regarding a year 3 surveillance referred to visual examination only, and no lift-off testing was scheduled or performed then. The staff finds the applicant's response acceptable because it is applying the provisions of Regulatory Position 1.5 of RG 1.35. Additionally, the applicant stated that its containments are identical in all aspects, that the initial structural integrity test for Unit 2 was performed in 1988 (prior to two years after the ISIT for Unit 1), and that there is no unique situation that would subject the containments to a different potential for structural or tendon deterioration.

RG 1.35, Section 2.4, states that the tendons to be inspected should be randomly selected from each tendon group, with the groups defined in Section 2.1 as vertical, hoop, dome, and inverted U, as applicable. Table IWL-2521-1 of the ASME Code requires that a defined minimum number of tendons of each type are to be examined and states that a tendon type is defined by its geometry and position in the containment (e.g., hoop, vertical, dome, helical, and inverted U). Both RG 1.35 and the ASME Code require examination of each type of tendon in every inspection interval. LRA Section 4.5 provides acceptance criteria for minimum lift-off force for three groups of tendons—inverted U-shaped vertical tendons, horizontal dome tendons, and horizontal wall tendons. Table 4.5-1 uses the same grouping. The staff noted that, in Table 4.5-1, there are no data for the examination of horizontal dome tendons for Unit 1 year 20 or Unit 2 years 5 or 15. The staff is unclear as to whether the applicant considers the horizontal dome tendons as a separate tendon group from the horizontal cylinder tendons and, if so, why dome tendons are not consistently inspected at each interval. The staff also noted that four Unit 2 horizontal dome tendons were surveyed in year 10 even though the inspection schedule for Unit 2 is for year 5 and year 15 (not year 10).

In a teleconference on January 4, 2012, the staff requested that the applicant explain, given the requirements to examine a minimum number of tendons of each type, why there are no surveillance data for horizontal dome tendons for the inspection intervals listed above. The applicant responded that the horizontal tendons in the dome are grouped with the horizontal tendons in the cylinder wall. For both the horizontal and vertical tendons, the tendons scheduled to be inspected during each interval are selected at random. There is one control tendon in each group that is inspected at each interval; otherwise, the sample of tendons inspected is always different. Since the horizontal tendons are considered one group and randomly selected for inspection, it is possible that a dome tendon will not be selected. The staff finds the applicant's response acceptable because the applicant clarified that although LRA Section 4.5 and Table 4.5-1 separately consider dome tendon acceptance criteria and inspection results, the applicant's post-tensioned containment is designed with horizontal tendons considered as one group. It follows that since the tendons to be inspected are randomly selected, dome tendons may not be included in the inspection sample at every interval.

In response to the staff's request to explain why there was a year-10 surveillance done outside of the originally defined inspection schedule, the applicant stated that the inspection was done as a result of the discovery that errors had been made in the methodology for determining the prescribed lower limit of the tendon prestressing forces. One tendon in each unit and the adjacent tendons were retested during the year-10 interval. This issue is discussed further in Section 3.0.3.1.9, "Concrete Containment Prestress," of this SER.

The staff noted that in the applicant's Concrete Containment Tendon Prestress Program one tendon of each type is designated as the control tendon, to be examined during every inspection interval, in accordance with RG 1.35 and ASME Code Section IWL. The expectation is that prestressing tendons will lose their prestressing forces with time due to creep and shrinkage of concrete and relaxation of the prestressing steel. In its review of the tendon regression analysis input data (Table 4.5-1) of the LRA, the staff noted that in Unit 1, the lift-off force for the vertical U-shaped control tendon V126 increased from 1,340 kips (shop end) and 1,380 kips (field end) at the year-10 inspection to 1,363.16 kips (shop end) and 1,389 kips (field end) at the year-20 inspection. There was also an increase in prestressing force between the year-10 and year-20 interval inspection of the Unit 1 horizontal cylinder (wall) control tendon 1H091. Examinations of vertical and horizontal control tendon lift-off measurement results for Unit 2 did not result in any increases in lift-off forces. In a January 4, 2012, teleconference, the staff requested that the applicant explain these anomalies. The applicant responded that it used a different vendor for the testing machinery used in the year-10 and year-20 inspection intervals, and that there may have been slight inaccuracies in calibration. The applicant stated that there is no other reason why larger forces were measured in the two tendons. The applicant justified the results by citing the provisions of ASME Code Section IWL-2522(b), which states that "equipment used to measure tendon force shall be calibrated prior to the first tendon force measurement and following the final tendon force measurement of the inspection period." ASME Code Section IWL-2522(b) also states that the "accuracy of the calibration shall be within 1.5 [percent] of the specified minimum ultimate strength of the tendon." The applicant stated that for all instances in which the year-20 lift-off force was larger than the year-10 lift-off force, the largest discrepancy is for the shop end of tendon V126, where the tendon was measured to gain 23.16 kips of prestressing force rather than the predicted loss of 10 kips. The applicant stated that the delta of 33 kips is within the acceptance criteria of 1.5 percent ASME Code Section IWL-2522. The staff was unclear as to how the applicant applied provisions of IWL-2522(b) to tendon liftoff forces over successive intervals, when IWL-2522(b) applies to calibration of the hydraulic lift-off jack over the same inspection interval. The staff determined that it needed more information to complete its review.

By letter dated February 15, 2012, the staff issued RAI 4.5-1, requesting that the applicant explain how it applied the provisions of IWL-2522(b) to the condition of the surveillance measuring an increase in lift-off force when the tendon was predicted to relax. The staff requested that the applicant explain its basis for applying IWL-2522(b) to the lift-off results for individual tendons and provide details of the calibration measurements of the jacking equipment used to perform the tendon surveillance. In its letter dated March 12, 2012, the applicant responded stating that surveillances performed 10 years apart by different vendors using different equipment cannot be assumed to produce results that are more accurate than the calibration tolerance specified in the ASME Code. ASME Code Section IWL-2522(b) allows accuracy of the tendon calibration to be within 1.5 percent of the specified minimum ultimate strength of the tendon. The applicant stated that its tendons each have 186 wires of one-quarter inch diameter, for a total cross section of 9.13 square inches. The material ultimate strength is 240 ksi. Therefore, 1.5 percent of the specified minimum ultimate strength of one tendon is 33 kips. The largest discrepancy between the measured and predicted tendon forces was in tendon V126 (shop end), where between the 10-year and 20-year inspection interval, the tendon was predicted to lose 10 kips of prestressing force but measured an increase in prestress by 23 kips instead, for a total difference of 33 kips (which is the upper limit allowed by the ASME Code). The staff finds the applicant's response acceptable because the apparent increase in the three noted tendon liftoff forces between years 10 and 20 can be attributed to measurement and equipment errors, and that the error remains within the ASME Code allowable 1.5 percent calibration tolerance of tendon liftoff forces. The staff's concern discussed in RAI 4.5-1 is resolved.

The applicant's program meets the acceptance criteria in SRP-LR Section 4.5.2.1.3 because it assesses the concrete containment tendon prestressing forces, and the staff has determined that the AMP is acceptable to address concrete containment tendon prestress in accordance with 10 CFR 54.21(c)(1)(iii), except for operating experience. The staff reviewed the applicant's operating experience related to the containment tendon prestressing surveillances. The results of the review are documented in the staff evaluation of the Concrete Containment Tendon Prestress Program in SER Section 3.0.3.1.9. The results show that the applicant's program has adequately considered plant-specific operating experience.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions of the concrete containment prestressed tendons will be adequately managed for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.5.2.1.3 because the Containment Tendon Prestress Program assesses the concrete containment tendon prestressing forces, and the staff has determined that the program is an acceptable way to manage aging of the containment tendon prestressing system.

4.5.3 UFSAR Supplement

LRA Section A3.4 provides the UFSAR supplement summarizing the Containment Tendon Prestress TLAA. The staff reviewed LRA Section A3.4, consistent with the review procedures in SRP-LR Section 4.5.3.2, which state that a summary description of the evaluation of tendon prestress TLAA should be included in the UFSAR supplement. Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.5.3.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the Concrete Containment Prestress TLAA, as required by 10 CFR 54.21(d).

4.5.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions of the containment prestressing system will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.6 Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis

4.6.1 Containment Liner Plate, Containment Equipment Hatches, and Containment Polar Crane Brackets

4.6.1.1 Summary of Technical Information in the Application

LRA Section 4.6 describes the applicant's TLAA for the containment structure liner, which is a leak-tight membrane made of welded carbon steel plates attached to the inside face of the concrete shell. The LRA states that the containment structure including the liner is designed in accordance with the proposed ACI 359-ASME Code, Section III, Division 2, issued for trial use and comments in 1973, including subsequent addenda 1-6, Bechtel Topical Report BC-TOP-1, "Containment Building Liner Plate Design Report," and Bechtel Topical Report BC-TOP-5A, "Prestressed Concrete Nuclear Reactor Containment Structures."

The applicant stated that a review of the penetration specification, liner specification, containment building design report, and design calculations found the application of cyclic limits to the design to be time-dependent only for design of the personnel and emergency airlocks and some of the process penetrations.

Design Criteria and Design Codes. The applicant stated that the post-tensioned concrete containment vessels were poured against steel membrane liners. The applicant also stated that no credit is taken for the liner for the pressure design of the containment vessel, but the liner and penetrations ensure the vessel is leak-tight, and its electrical, process, personnel airlock, and equipment hatch penetrations are part of the containment pressure boundary.

The LRA states that the liner fatigue evaluation was performed in accordance with the design and construction specifications of Subsections NE-3222.4 and NE-3131(d) of the ASME Code Section III, Division 1, 1974 or later. The LRA also states that subparagraph NE-3222.4 of the ASME Code provides rules for fatigue analysis of MC components subject to operating condition cyclic loads and thermal conditions, where part NE-3222.4(d) specifically addresses waivers to such an analysis. The LRA further states that the reference is to ASME Code Subsection NE; any TLAAs arising from its use would apply only to the containment liner, penetrations, airlocks, and hatches.

Containment Liner Plate. The LRA states that the containment liner and penetrations were designed to BC-TOP-1 and ASME Code Section III, Division 2, issued for trial comment in 1973, including addenda 1-6. The applicant stated that it performed a thorough search of the CLB, including the liner specification and the containment building design report and found no indication of any fatigue analysis or design reference for a stated number of cyclic loads for the containment liner plate.

The applicant stated that the containment liner plate fatigue TLAA acceptance, as assigned by Section 4.6 of SRP-LR, Revision 2, does not meet the requirements of Criterion 6 of 10 CFR 54.3(a). This criterion states that TLAAs for the purposes of this part are those applicant calculations and analyses that “are contained or incorporated by reference in the CLB.”

Equipment Hatches. The applicant stated that the Unit 1 and 2 equipment hatches were designed to ASME Code Section, 1971 edition, winter 1973 addenda. The applicant further stated that the design report exhibits no design for a stated number of load cycles or any other evidence of a TLAA.

The applicant stated that the equipment hatches TLAA acceptance, assigned by Section 4.6 of the SRP-LR, is not in accordance with Criterion 3 of 10 CFR 54.3(a). This criterion states that TLAAs for the purposes of this part “involve time-limited assumptions defined by the current operating term, for example, 40 years.”

Personnel and Emergency (Auxiliary) Airlocks. The applicant stated that the personnel and emergency (auxiliary) airlocks were specified to ASME Code Section III Division 1, Subsection NE, Class MC components, 1974 edition, winter 1974 addenda, but were analyzed to the winter 1975 addenda. The applicant also stated that an NB-3222.4(d) fatigue waiver for each depends, in part, on the assumed number of load cycles and is, therefore, a TLAA.

The applicant dispositioned the personnel and the emergency (auxiliary) airlocks TLAA in accordance with 10 CFR 54.21(c)(1)(ii), that the analysis has been projected to the end of the period of extended operation.

Polar Crane Brackets. The applicant stated that the polar crane is supported on a system of girders, which are supported by a series of brackets that are attached to the containment shell. The applicant also stated that the design of the polar crane brackets neither reports nor specifies a fatigue analysis. The applicant further stated that the current steel code specifies that no evaluation of fatigue resistance is required if the number of cycles of application of live load is less than 20,000, which is greater than the expected 3,542 lifts for the polar crane.

The LRA states that the polar crane brackets TLAA acceptance, as assigned by Section 4.6 of the SRP-LR does not meet the requirements of Criterion 3 of 10 CFR 54.3(a). This criterion states that TLAAs for the purposes of this part “involve time-limited assumptions defined by the current operating term, for example, 40 years.”

Penetrations. The applicant stated that the design of some containment penetrations includes a fatigue analysis. The applicant dispositioned the penetrations TLAA in accordance with 10 CFR 54.21(c)(1)(i), which states that the analysis remains valid during the period of extended operation, and 10 CFR 54.21(c)(1)(iii), which states that the effects of aging on the intended functions will be adequately managed for the period of extended operation.

4.6.1.2 Staff Evaluation

The staff reviewed LRA Section 4.6 and the containment liner, equipment hatches, and polar crane brackets TLAA to confirm, pursuant to 10 CFR 54.21(c)(1), that the analyses either remain valid during the period of extended operation, have been projected to the end of the period of extended operation, or that the effects of aging on the intended functions will be adequately managed for the period of extended operation. The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with the review procedures in SRP-LR Section 4.6.3.1.1.

The staff reviewed the UFSAR and verified that the proposed ACI 359-ASME Code, Section III, Division 2 and BC-TOP-5A are referenced. The applicability of these codes are reviewed and discussed in the appropriate sections for each of the staff's evaluations below.

Design Criteria and Design Codes. The staff reviewed the UFSAR and determined that it contains the referenced ASME Codes. The applicability of these codes are reviewed and discussed in the appropriate sections for each of the staff's evaluations below.

Containment Liner Plate. The staff reviewed the applicant's claim that the lack of any CLB information related to containment liner plate cyclic loading or any fatigue analysis excludes the liner plate from TLAA consideration, per TLAA Criterion 6 in 10 CFR 54.3(a). The staff also noted that UFSAR Section 3.1.2.5.5.1 and Table 3.2.A-1 state that the liner plate was specified not to require N-stamping.

The staff examined the UFSAR for a specific entry on fatigue or cycles of loading to fulfill the review in accordance with the SRP-LR. The staff noted that UFSAR Section 3.8.1.5.9 states that "[t]he effect of cycled stresses and strains in the liner is considered by performing a fatigue analysis, in accordance with Section 3.8.1.5.6, which includes the reactor shutdown-startup cycles." The staff also reviewed UFSAR Sections 3.8.1.2 and 3.8.1.5.6 which state that the allowable stresses and strains in the liner plate should be in accordance with the Proposed ACI 359-ASME Code, Section III, Division 2, Concrete Reactor Vessels and Containments. Section CC-3760 of the Proposed ACI 359-ASME Code states that the design of liners is not considered to be fatigue-controlled because the stress and strain changes would occur only a small number of times and produce minor stress-strain fluctuations. Furthermore, for strains due to earthquakes and design basis accidents, the Code states that these are too infrequent and with too few cycles to be controlling. Nevertheless, the staff noted that the Code holds the designer responsible to meet the Design Specifications for cyclic loading and thermal conditions.

The staff also noted that the requirements for cyclic loading are stated in UFSAR Section 3.8.2.5.5.3, which references the ASME Code Section III, Division 1, Sections NE-3131(d) and NE-3222.4(d). The ASME Code NE-3131(d) (1974 editions or later) rules out consideration for earthquake transients unless they impact designated liner locations recognized in the specifications. ASME Code NE-3222.4(d), "Analysis for Cyclic Operations, Vessels Not Requiring Analysis for Cyclic Operation," provides for a relief from fatigue analysis when certain cyclic loading criteria are met. The staff further reviewed the UFSAR and Bechtel Topical Report BC-TOP-1, "Containment Building Liner Plate Design Report, Part I: Liner Plate and Anchorage System," and other available topical reports and specifications for applicable cyclic loads or calculations that consider the number of cycles satisfying the exclusion criteria of NE-3222.4(d). The staff noted that the aforementioned documents had no entries for cyclic loading calculations and did not consider fatigue analysis of the liner plate.

The staff noted that there was an apparent inconsistency or gap with regard to the information that was provided by the applicant on the design requirements for the containment liners. Therefore, by letter dated September 22, 2011, the staff issued RAI 4.1-2, requesting that the applicant clarify if subparagraph NE-3222.4 in the 1974 edition of the ASME Code was used for the containment liners. The staff also asked the applicant to justify why fatigue analyses for the containment liner plate were not performed in accordance with subparagraph NE-3222.4 of the 1974 ASME Code or to clarify if the liner had been exempted (waived) from fatigue analysis under provisions of NE-3222.4(d). If the liner plate was waived from fatigue analysis under NE-3222.4(d), the staff requested clarification on why the fatigue waiver analysis would not need to be identified as a TLAA for the LRA in the manner that the fatigue waiver analysis for the personnel and emergency (auxiliary) air locks was identified as a TLAA in the LRA.

The applicant responded to RAI 4.1-2 by letter dated November 21, 2011. In its response, the applicant stated that the containment liner was not designed to the ASME Code, Section III, subarticle NE-3000, design requirements. The applicant stated that UFSAR Section 3.8.1.2 identifies that the containment liner was designed to the 1973 edition of the ASME Code, Section III, Division 2, including addenda 1-6. The applicant also stated that the NRC approved Bechtel Specification BC-TOP-5-A as an acceptable means of meeting the ASME Code design criteria for the liner plate and that specification BC-TOP-5-A references the methodology in Bechtel Specification BC-TOP-1. The applicant further stated that this design method compares the stresses in BC-TOP-1, which are independent of the number of load cycles and have no fatigue analyses.

The staff confirmed the accuracy of the information in the applicant's RAI response through an audit of the applicant's design specification for the containment liner, penetrations, airlocks, and equipment hatches, with the exception of one matter that needed clarification by the applicant. Specifically, the staff noted that the design specification states that the "requirements for an 'analysis of cyclical loading' will be investigated in accordance with Section NE-3222.4 and NE-3121 of the ASME Code Section III." However, the staff noted that the design specification did not identify which of the containment components in the design specification were within the scope of the design specification's fatigue analysis statement. Thus, the staff found that additional information was needed to clarify whether the fatigue analysis statement in the design specification was only applicable to those containment components designed to ASME Code, Section III, Division 1, requirements (e.g., the containment penetrations) or whether the fatigue analysis statement in the design specification was also applied to the containment liner that was designed to ASME Code, Section III, Division 2, requirements.

By letter dated February 15, 2012, the staff issued RAI 4.1-2a, requesting additional clarification on whether the fatigue analysis statement in the containment liner design specification was only applicable to those components in the specification that were designed to ASME Code, Section III, Division 1, requirements (e.g., the containment penetrations) or if it also applied to the containment liner plate, which was designed to ASME Code, Section III, Division 2, requirements.

The applicant responded to RAI 4.1-2a by letter dated March 29, 2012. In its response, the applicant stated that, upon review of the design specification for the containment structures, it confirmed that the design specification did not require the containment liners to be analyzed to ASME Code, Section III, Division 1, requirements because they were not qualified as pressure-retaining components for the containment structures. The applicant stated that the containment liners were only analyzed to ASME Code, Section III, Division 2, requirements, which did not require the liners to be the subject of a CUF-based fatigue analysis. Based on this review, the staff finds that the applicant has resolved the issue on whether the design specification for the containment liners required the liners to be analyzed with a fatigue analysis. Additionally, based on the response to RAI 4.1-2a, the staff finds that the LRA does not need to include a fatigue analysis-based TLAA for the containment liners because the containment liners are containment pressure boundary components that do not need to be analyzed to

ASME Code, Section III, Division 1, requirements. The staff's concerns in RAI 4.1-2a are resolved.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.3(a), that the liner plate does not meet Criterion 6, Section 4.1 of the SRP-LR. Therefore, the liner plate is not a TLAA.

Equipment Hatches. The staff reviewed the applicant's claim that the design of the equipment hatches is not a TLAA and verified that the lack of any CLB material related to "Containment Equipment Hatches" cyclic loading or its fatigue analysis excludes the equipment hatches from TLAA consideration, pursuant to the review procedure delineated in SRP-LR, Revision 2, Section 4.1.3, which states that "[t]he defined operating term should be explicit in the analysis. Simply asserting that a component is designed for a service life or plant life is not sufficient. The assertion is supported by calculations or other analyses that explicitly include a time limit."

The staff reviewed UFSAR Section 3.8.1.5.9, "Effect of Repeated Reactor Shutdowns and Startups During the Plant's Life," and verified that thermal cycling and startups and shutdowns are considered over a 40-year plant life. The staff also reviewed applicant topical and vendor reports to locate calculations and analyses that could demonstrate the fatigue life of equipment hatches to be limited by reactor startup and shutdown cyclic loading of 40 years and did not locate any calculations. The staff noted that Section 3.8.2, "Steel Containment System (ASME [Code] Class MC Components)," of the UFSAR indicates that the equipment hatches are designed, fabricated, and installed in accordance with ASME Code Section III, Class MC components and that the equipment hatches are not stamped because they are an integral part of an unstamped containment vessel. The staff noted that BC-TOP-5A, which addresses the design of the reactor building containment, includes the equipment hatch openings as part of the structure. Through review of the referenced topical reports in the LRA, resolution of RAI 4.1-2 discussed above and in Section 4.1.2 of this SER, and review of other applicant-supplied vendor technical information, the staff confirmed that the equipment hatches have no cyclic loading requirements.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.3(a), that the equipment hatches are not TLAAs because they do not satisfy Criterion 3, Section 4.1 of NUREG-1800, Revision 2, "Standard Review Plant for Review of License Renewal Applications for Nuclear Power Plants."

Personnel and Emergency (Auxiliary) Airlocks. The staff's evaluation of personnel and emergency (auxiliary) airlocks is in SER Section 4.6.2.

Polar Crane Brackets. The staff reviewed the applicant's claim that the polar crane brackets are not TLAAs and verified that the lack of any CLB material related to polar crane brackets cyclic loading or its fatigue analysis excludes the polar crane brackets from TLAA consideration, pursuant to the review procedure delineated in SRP-LR Section 4.1.3. This section states that "[t]he defined operating term should be explicit in the analysis. Simply asserting that a component is designed for a service life or plant life is not sufficient. The assertion is supported by calculations or other analyses that explicitly include a time limit."

The staff reviewed Bechtel Topical Report BC-TOP-1, the UFSAR Section 3.8.1.2.1-referenced "American Institute of Steel Construction (AISC) Specifications—AISC Specification for Structural Steel Buildings, 1969," supplements 1, 2, and 3, and other vendor topical reports to identify any calculations that involve time-limited assumptions defined by the current operating term of 40 years. The staff noted that, in accordance with UFSAR Section 3.8.3.2, "Applicable Codes, Standards and Specifications," the code of record for cranes is the Crane Manufacturers

Association of America (CMAA) Specification 70. The staff also noted that the Bechtel Topical Reports, BC-TOP-1 and BC-TOP-5A, do not contain cyclic loadings or report fatigue analyses calculations for the polar crane brackets. The staff further reviewed the latest AISC Load and Resistance Factor Design Specifications and confirmed the applicant's claim that the specifications do not consider fatigue to be applicable when the number of cycles of live loads for the life of the crane is less than 20,000.

The staff finds that the applicant has demonstrated, pursuant to 10 CFR 54.3(a), that the polar crane brackets are not TLAAs because they do not satisfy Criterion 3, Section 4.1 of NUREG-1800, Revision 2, "Standard Review Plant for Review of License Renewal Applications for Nuclear Power Plants."

4.6.1.3 UFSAR Supplement

The staff concludes that no UFSAR supplement is required for the containment liner plate, equipment hatches, and polar crane brackets because these components do not require TLAAs.

4.6.1.4 Conclusion

On the basis of its review, the staff concludes that containment liner plate, equipment hatches, and polar crane brackets do not require TLAAs.

4.6.2 Fatigue Waivers for the Personnel Airlocks and Emergency (Auxiliary) Airlocks

4.6.2.1 Summary of Technical Information in the Application

LRA Section 4.6.1 describes the applicant's fatigue waiver analysis for the personnel and emergency (auxiliary) airlocks. It states that the design of the personnel and emergency airlocks included an ASME Code Section III NE-3222.4(d) fatigue waiver analysis, which confirmed that a fatigue analysis was not required. The LRA also states that the fatigue waiver analyses themselves depend on the number of assumed load cycles, and are therefore TLAAs.

<u>Analysis of Fatigue Waiver for the Personnel Airlocks</u>. The applicant stated that the fatigue waiver for the personnel airlocks applied values from the reactor containment structures specification to determine if the six criteria of ASME Code Section III NE-3222.4(d) are met. The applicant also stated that the fatigue waiver analysis demonstrated that the specified maximum allowable 1,900 startup and shutdown cycles satisfies the ASME Code NE-3222.4(d) criteria. This allowable number of cycles, however, is much higher than the assumed 120 cycles.

The applicant dispositioned the personnel airlocks TLAA in accordance with 10 CFR 54.21(c)(1)(ii), that the analyses have been projected to the end of the period of extended operation.

<u>Analysis of Fatigue Waiver for the Emergency (Auxiliary) Airlocks</u>. The applicant stated that the fatigue waiver for the emergency (auxiliary) airlocks assumed three values not supplied by the reactor containment structures specification to determine if the six criteria of ASME Code Section III NE-3222.4(d) are met. The applicant reported the following loading cycles: test temperature and pressure (10 cycles), operating temperature (300 cycles), and operating basis earthquake (OBE) (500 cycles).

The applicant also stated that for this fatigue waiver, analyses of the emergency (auxiliary) airlocks Criteria 4 and 6 of Section NE-3222.4(d) of the ASME Code are time-dependent. The fatigue waiver analysis demonstrated that the assumed conservative operating temperature range was within the limit determined for the assumed number of cycles by ASME Code NE-3222.4(d), Criterion 4, and will remain so even if the assumed number of cycles is increased from 300 to 450 to account for the period of extended operation. The analysis also demonstrated that the stress range allowed by Criterion 6 for the expected number of mechanical cycles would not be exceeded if the assumed number of cycles were increased from 500 to 750 to account for the period of extended operation.

The applicant dispositioned the emergency (auxiliary) airlocks TLAA in accordance with 10 CFR 54.21(c)(1)(ii), that the analyses have been projected to the end of the period of extended operation.

4.6.2.2 Staff Evaluation

Fatigue Waiver for Personnel Airlocks. The staff reviewed LRA Section 4.6.1 regarding the fatigue waiver of personnel airlocks TLAA to confirm pursuant to 10 CFR 54.21(c)(1)(ii), that the analysis has been projected to the end of the period of extended operation.

The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with the review procedures in SRP-LR Section 4.6.3.1.1.2, which states that the operating transient experience and the increased number of assumed cyclic loads projected to the end of the period of extended operation are to be reviewed to ensure that the cyclic load projection is adequate. The SRP-LR also states that for the re-evaluation, the code of record either remains the same or the applicant may update it to a later edition pursuant to the requirements of 10 CFR 50.55a.

For the personnel airlocks, the staff reviewed the LRA, the applicant's UFSAR, and the applicant-provided vendor information. The staff verified in UFSAR Section 3.8.2.2.2, "Applicable, Codes, Standards, and Specifications," that applicant's code of record is the ASME Code Section III, Division I, 1974 edition, including winter 1975 addenda. The staff also reviewed UFSAR Section 3.8.2.1, "Design Basis," item 3, which states that the personnel airlocks' penetrations are designed to accommodate thermal and mechanical stresses encountered in normal and other modes of operation and testing. The staff verified the applicant's claim that temperature, pressure, and OBE are the loading conditions for which the personnel airlocks need to be evaluated. The staff noted that UFSAR Section 3.8.1.1.6, "Containment Penetrations and Attachments," and Section 3.8.1.6.4.1, "Liner and Attachments: Materials," state that personnel airlocks' penetrations are part of the containment pressure boundary and are double door welded-steel assemblies made of SA-516 Grade 70 or SA-537 Class 1 steel per ASME Code Section III, Division 1, Subsection NE, Class MC component criteria. The staff also noted that UFSAR Section 3.8.2, "Steel Containment System ([ASME Code] Class MC Components)," states that the personnel airlocks are tested and receive a nameplate with an N symbol stamp, which indicates their conformance to the ASME Code.

The staff considered the applicant's claim of fatigue waiver per the applicable code of record. The staff reviewed UFSAR Section 3.8.2.2.2, "Other Applicable Codes, Standards and Specifications" and Section 3.8.2.4, "Design and Analysis Procedures," and confirmed that the Class MC items and components (i.e., airlocks) are analyzed and designed in accordance with the applicable requirements of Section NE-3131(d) of the ASME Code Section III, Division I, 1974 edition. Section NE-3131(d) requires further evaluation per Section NE-3222.4(d), of the code. The staff reviewed the requirements of ASME Code Section NE-3222.4(d), "Analysis for Cyclic Operation, (d) Vessels Not Requiring Analysis for Cyclic Operation" and noted that the following operating conditions must be analyzed for a fatigue waiver:

- atmospheric-to-operating pressure cycles
- normal operation pressure fluctuation
- temperature difference—startup and shutdown
- temperature difference—normal operation
- temperature difference—dissimilar materials
- mechanical loads

The staff also noted that UFSAR Section 3.8.2.4 discusses the analysis and design of the personnel airlocks performed by a selected vendor, using appropriate conventional engineering methods. The referenced calculations are not included in the applicant's UFSAR. However, per 10 CFR 54.3, Criterion 6, and Section 4.1 of the SRP-LR, these calculations and analyses are part of the TLAA acceptance criteria, hence the analyses are incorporated by reference in the CLB. The staff audited applicant-provided code of record reference (vendor) calculations and noted that the TLAA has been addressed. The staff noted that UFSAR Section 3.9.1.1.6.10, "Refueling," addresses the applicant's assumed atmospheric-to-operating pressure cycles to be 80, for the life of the plant initially set at 40 years. The staff noted that LRA Section 4.6.2, "Fuel Transfer Bellows," states that that one thermal cycle occurs during each refueling operation; hence, there are 80 thermal cycles for 40 years or 120 for 60 years, which includes the period of extended operation. The staff independently performed confirmatory calculations for SA-516 Grade 70 steel (note: SA-537 Class 1 steel has higher minimum tensile and yield strengths) used in the fabrication of the personnel airlocks per Section 3.8.1.1.3, "Steel Liner," of the UFSAR. This section states that "[a]n increased plate thickness up to 2 in. is provided around all penetrations." The staff confirmed the validity of the applicant's claim for the maximum code allowable 1,900 startup and shutdown cycles. The airlock meets the following applicable conditions identified by the NE-3222.4(d) of the ASME Code:

- Atmospheric-to-Operating Pressure Cycle—Three times the design stress intensity (S_m) value for a ferrous material (SA-516 Grade 70) at operating temperatures corresponds to an allowable stress value (Sa) of 69.9 ksi, which yields 1,900 cycles from the fatigue curve of Figure I-9.0 of the ASME Code.

- Normal Operation Pressure Fluctuation—Maintaining the limit of 1,900 cycles corresponds to an allowable stress intensity of 69.9 ksi, which yields the calculated design pressure of 56.5 psig discussed in Section 2.5.4.10.4.1.5, "Internal Pressure Condition," and Table 6.2.1.1-3, "Containment Data Used in P/T Analysis," of the UFSAR.

- Temperature Difference—Startup and Shutdown—The temperature difference between any two adjacent points of the containment boundary for the limit 1,900 cycles is below the roughly 190 °F temperature difference at which fatigue would become noteworthy. In accordance with Table 6.2.1.1-3, "Containment Data Used in P/T Analysis," of the UFSAR, temperature during operation does not exceed 114 °F.

- Temperature Difference—Normal Operation—It remains within bounds of difference between design temperature of 286 °F and the operating temperature of 114 °F per Table 6.2.1.1-3, "Containment Data Used in P/T Analysis," of the UFSAR. Specifically, Section 3.9.1.1.6.1 of the UFSAR specifies 400 heatup-cooldown operations over 40 years. The LRA redefines these in Table 4.3-2, "STP Units 1 and 2 Transient Cycle

Count 60-year Projections," for 60 years to be 171 and 154 cycles for Unit 1 and Unit 2, respectively. Considering the average of the operating and design temperatures to be about 200 °F, this condition yields for about 171 cycles an allowable stress intensity of 175 ksi and an allowable temperature difference for normal operation of about 450 °F, which is above the 172 °F temperature difference of operating and design temperatures.

- Temperature Difference—Dissimilar Materials—The staff further reviewed the UFSAR for dissimilar materials that may have been used in the fabrication of the personnel airlocks and found none. The staff also noted that this evaluation is in accordance with the audited applicant's vendor provided calculations.
- Mechanical loads—These were determined to be not applicable per staff review of applicant-provided vendor information called for by the code of record referenced calculations.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the analyses for the personnel airlocks have been projected to the end of the period of extended operation.

<u>Fatigue Waiver for Emergency (Auxiliary) Airlocks</u>. The staff reviewed LRA Section 4.6.1 regarding the fatigue waiver of the emergency (auxiliary) airlocks TLAA to confirm pursuant to 10 CFR 54.21(c)(1)(ii), that the analysis has been projected to the end of the period of extended operation.

The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with the review procedures in SRP-LR Section 4.6.3.1.1.2, which states that the operating transients experienced and the increased number of assumed cyclic loads projected to the end of the period of extended operation are to be reviewed to ensure that the cyclic load projection is adequate. The SRP-LR also states that for the re-evaluation, the code of record either remains the same or the applicant may update it to a later edition pursuant to the requirements of 10 CFR 50.55a.

For the emergency (auxiliary) airlocks, the staff reviewed the LRA, the applicant's UFSAR, and vendor information provided by the applicant. The staff noted in UFSAR Section 3.8.1.6.4.1 "Liner and Attachments: Materials," that the emergency (auxiliary) airlocks are also made of SA-516 Grade 70 steel or SA-537, ASME Code Section III, Division 1, Class 1 steel. The staff independently performed confirmatory calculations for a plate thickness of 2 in. made with the lower tensile and yield strength SA-516 Grade 70 steel.

The staff noted that conditions 1, 2 and 3 of NE-3222.4(d) of the ASME Code, as discussed in the section above, "Fatigue Waiver for the Personnel Airlocks," are equally applicable to the emergency (auxiliary) airlocks because the two airlock types (personnel and the emergency/auxiliary) are addressed and referenced within the same UFSAR sections. Therefore, the calculations for the atmospheric-to-operating pressure cycle, normal operation pressure fluctuation, and temperature difference—startup and shutdown are the same for the emergency (auxiliary) airlocks. The staff further noted that the design cycles for test transients are limited to 10 cycles and are independent of any other transients (e.g., see UFSAR 3.9.1.1.10.1, "Primary Side Hydrostatic Test," and 3.9.1.1.10.2 "Secondary Side Hydrostatic Test"). The staff also noted that LRA Table 4.3-2, "STP Units 1 and 2 Transient Cycle Count 60-year Projections," for test conditions, limits the transients to one for each unit.

The emergency (auxiliary) airlock meets the remaining conditions identified by the NE-3222.4(d) of the ASME Code, as follows:

- Temperature Difference—Normal Operation—An assumed number of 300 cycles, when increased by 1.5 times to 450 cycles and considering the average of the operating and design temperatures to be about 200 °F, yields an allowable stress intensity of 110 ksi and an allowable temperature difference of about 285 °F, which is greater than the 172 °F difference of operating and design temperatures.
- Temperature Difference—Dissimilar Materials—The staff reviewed the UFSAR for dissimilar materials that may have been used in the fabrication of the emergency (auxiliary) airlocks and found none.
- Mechanical Loads—The LRA Section 4.6.1 lists 500 cycles for OBE, which is far in excess of those reported in UFSAR 3.7.3A.2, “Determination of Number of Earthquake Cycles.” The UFSAR defines the total number of earthquake cycles for the design of seismic Category 1 SSCs to be 10 for SSEs (one event) and 50 for OBEs (five events). These values are in accordance with Table 4.3-2 of the LRA. The staff audited the applicant-provided code of record referenced (vendor) calculations and noted that the TLAA has been addressed and that the 500 cycles listed in the LRA are due for a range of mechanical loads that include earthquake loading. The staff then independently performed confirmatory calculations increasing the 500 cycles by 1.5 times to 750 cycles, which yielded an allowable stress intensity (Sa) range of 95 ksi. This is higher than the maximum allowable factored overload stress (38 ksi times 1.33) if indeed all the stresses and all the cycles were due to seismic loads, and there were no potential crack initiators. The staff also noted that the applicant-provided vendor information called for by the code of record has a calculated stress intensity of 60 ksi.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the analyses for the emergency (auxiliary) airlock have been projected to the end of the period of extended operation.

4.6.2.3 UFSAR Supplement

LRA Section A3.5.1, “Fatigue Waivers for the Personnel Airlocks and Emergency (Auxiliary) Airlocks,” provides the UFSAR supplement summarizing the personnel and emergency airlock fatigue waiver analysis per code of record and design calculations and documents called for by that code of record. The staff reviewed LRA Section A3.5.1, consistent with the review procedures in SRP-LR. Section 4.1.3 of the SRP-LR states that if a code of record is in the UFSAR for particular group of structures or components, reference material includes all calculations called for by that code of record for those structures and components. Section 4.6.3.1.1.2 of the SRP-LR states that the operating transients experienced and the increased number of assumed cyclic loads projected to the end of the period of extended operation are to be reviewed to ensure that the cyclic load projection is adequate and that the fatigue waiver will remain valid for the period of extended operation.

Based on its review of the UFSAR supplement, the staff finds that it meets the acceptance criteria in SRP-LR Sections 4.1.3 and 4.6.3.1.1.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the fatigue waivers for the personnel airlocks and emergency (auxiliary) airlocks, as required by 10 CFR 54.21(d).

4.6.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(ii), that the analyses for the fatigue waivers for the personnel airlocks and emergency airlocks have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.6.3 Fatigue of Containment Penetrations

4.6.3.1 Summary of technical Information in the Application

LRA Section 4.6.2 states that a thorough search of the licensing basis and design documents identified all containment penetrations whose design is supported by a fatigue or cyclic load analysis. The LRA further states that these analyses are TLAAs.

The LRA states that the applicant evaluated the criteria in ASME Code Section III NC-3219.2(a) to determine whether fatigue analyses of penetrations are required. The calculation determined that fatigue analyses are necessary for main steam (M-1 through M-4), feedwater (M-5 through M-8), auxiliary feedwater (M-83, M-84, M-94, and M-95), and steam generator blowdown (M-62 through M-65) penetrations. Further examination of the design reports and calculations for each penetration type identified an additional fatigue analysis for sample line penetrations M-85 and M-86. Table 4.6-1 summarizes the result of this document review. The penetration fatigue analyses were calculated in accordance with ASME Code Section NC-3200.

The applicant dispositioned the Containment Penetrations TLAA in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed for the period of extended operation.

<u>Fuel Transfer Tube Bellows</u>. The applicant stated that the fuel transfer tube penetration connects the refueling canal (inside the reactor containment building) to the spent fuel pool (inside the fuel handling building) and consists of a stainless steel pipe inside of a carbon steel sleeve. The applicant also stated that the stainless steel casing pipes with expansion bellows are welded to both ends of the sleeve. These bellows allow differential movement between the buildings on the outside of the containment wall and between the containment liner and the refueling cavity concrete on the inside. The casing pipe and the bellows in the fuel handling building perform a leakage boundary intended function and are within the scope of license renewal. The applicant further stated that the casing pipe and the bellows inside the containment building are part of the containment pressure boundary and are within the scope of license renewal with a structural pressure boundary intended function. Each of these bellows is designed for 1,000 cycles of expansion and contraction; therefore, these design analyses are TLAAs requiring evaluation for the period of extended operation.

Furthermore, the applicant stated that in order to determine if the design analyses remain valid for 60 years of operation, it conservatively projected the number of cycles for 60 years. For each of these components, one thermal cycle occurs during each refueling operation. The applicant then stated that the design number of refueling operations is 80 cycles (120 cycles when multiplied by 1.5 for 60 years). In addition to these cycles, the fuel transfer canal penetration assembly is exposed to pressurization cycles during integrated leak rate tests, conservatively projected to occur once every 5 years. This contributes 12 cycles in 60 years. These penetrations would also be exposed to up to one safe shutdown earthquake cycle.

Therefore, the total cycles projected for 60 years are a fraction of the design cycles analyzed for these bellows.

The applicant dispositioned the fuel transfer tube bellows as a TLAA in accordance with 10 CFR 10 CFR 54.21(c)(1)(i), that the analysis remains valid during the period of extended operation.

4.6.3.2 Staff Evaluation

The staff reviewed LRA Section 4.6.2 regarding the fatigue design of the containment penetrations TLAA to confirm, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed for the period of extended operation.

The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with the review procedures in SRP-LR Section 4.6.3.1.1.3, which states that the applicant's proposed AMP to ensure that the effects of aging on the intended function(s) of the penetrations are adequately managed for the period of extended operation, is reviewed.

For the containment penetrations, the staff reviewed the applicant's disposition of the TLAA in the LRA, which states that the fatigue analyses of the containment penetration pressure boundaries are dependent on the assumed 40-year number of transient cycles and are based on the existing Metal Fatigue of Reactor Coolant Pressure Boundary Program. This program, when enhanced, will be consistent with GALL Report AMP X.M1. The staff noted that the program, as amended by the applicant in letter dated January 26, 2012, is an existing program. This program ensures the numbers of transients experienced during the period of extended operation either remain below their design cycles or that appropriate corrective actions are taken that may include repair, replacement, or more rigorous analyses of the pressure boundary containment components. The staff also noted that for the containment penetration assemblies, the program manages fatigue based on one of its two available methods—the cycle counting (CC) or the Cycle Based Fatigue (CBF) management method. All penetrations are monitored using the CC method, except Containment Penetrations M-62 through M-65, listed in LRA Table 4.3-1, "Summary of CBF Monitored Locations in the STP Fatigue Management." These are CBF-monitored and managed to ensure that the CUF remains below the ASME Code allowable fatigue limit of 1.0. UFSAR Table 3.9-8, "Summary of Reactor Coolant System Design Transients," contains transients that are also tabulated in LRA Table 4.3-2, "STP Units 1 and 2 Transient Cycle Count 60-year Projections." The LRA states that the most limiting number of cycles for each transient is used as the limiting values for the program.

The staff's evaluation of the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program is documented in SER Section 3.0.3.2.28. The staff reviewed LRA Table 4.6-1, "Containment Penetration Assemblies," and noted that the 40-year CUFs for M-1 through M-8, M-62 through M-65, M-83 through M-86, and M-94 and M-95 are all less than 1.0. The staff also reviewed LRA Table 4.3-2 and noted the conservatism involved when comparing for each specific transient the design cycles (UFSAR design), the actual cycles to the year 2008 (baseline events), and the 60-years of operation cycles projected (projected events). The projections provided in LRA Table 4.3-2, "demonstrate that the 40-year design basis numbers of events are sufficient for 60 years." The staff multiplied the 40-year CUF based on the assumed number of transients by 1.5 to obtain a 60-year projected CUF. The 1.5 multiplier is based on the linear increase of the total projected number of cycles from 40 to 60-years divided by the alternating stress intensity corresponding total allowable cycles. The calculated CUF for all listed penetrations were less than 1.0. For the feedwater penetrations M-5 through M-8, seismic anchor movement, Condition A of ASME Code Section III, Division 1, NC-3219.2, states that fatigue analysis is not mandatory for materials having a specified minimum tensile strength not exceeding 80 ksi, when the total expected number of cycles is less than 1,000. The staff further noted that UFSAR Section 3.7.3A.2, “Determination of Number of Earthquake Cycles,” defines the total number of earthquake cycles for the design of seismic Category 1 SSCs to be 10 for SSEs (one event) and 50 for OBEs (five events).

The staff then reviewed the applicant’s response to RAI 4.3.2.4-2 that further describes the methodology the applicant’s procedures will follow daily in screening the experienced transients. The applicant’s procedures require the control room to complete daily screening data sheets and identify if there were any transients. If a transient occurs, a transient-specific datasheet is completed to record the plant’s conditions during the event. The applicant will assess these by interpreting the collected data, and identifying the transients of importance through a software application for the period of extended operation. At least once per refueling cycle, the information will be validated to ensure that an accurate transient count exists and that the actual transient severity remains within the design basis. The cycle counts are compared to action limits, and corrective actions are initiated when a transient exceeds 80 percent of its design limit.

The staff finds that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions of the containment penetrations will be adequately managed for the period of extended operation.

Additionally, the analysis meets the acceptance criteria in SRP-LR Section 4.6.3.1.1.3. The program will be enhanced prior to the period of extended operation, as indicated in the amended AMP with its UFSAR supplement A2.1 “Metal Fatigue of Reactor Coolant Pressure Boundary.” This supplement was updated by the applicant in letter dated November 21, 2011, which states that “[t]he program ensures that actual plant experience remains bounded by the transients assumed in the design calculations, or that appropriate corrective actions maintain the design and licensing basis by other acceptable means. If a cycle count or CUF value increases to a program action limit, corrective actions include fatigue reanalysis, repair, or replacement… Action limits permit completion of corrective actions before the design basis number of events is exceeded.” Based on this information, the program will ensure that the effects of aging on the containment penetrations intended function(s) will be adequately managed for the period of extended operation.

Fuel Transfer Tube Bellows. The staff reviewed LRA Section 4.6.2, “Fuel Transfer Tube Bellows,” regarding the fatigue design of the containment penetrations TLAA to confirm, pursuant to 10 CFR 54.21(c)(1)(i), that the analysis remains valid during the period of extended operation.

The staff reviewed the applicant’s TLAA and the corresponding disposition, consistent with the review procedures in SRP-LR Section 4.6.3.1.1.1, which states that the number of assumed transients used in the existing CUF calculations for the current operating term is compared to the extrapolation to 60 years of operation of the number of operating transients experienced to date. The comparison confirms that the number of transients in the existing analyses will not be exceeded during the period of extended operation.

The staff reviewed LRA Section 4.6.2 for the fuel transfer tube bellows and noted that the bellows were designed for 1,000 cycles of expansion and contraction. The applicant also stated that a thermal cycle occurs during each refueling operation. The design number of refueling operations is 80 cycles for 40 years or 120 cycles for 60 years of operation. In addition to these cycles, the fuel transfer canal penetration assembly is exposed to pressurization cycles during integrated leak rate tests (ILRTs), very conservatively projected to occur once every 5 years. This contributes 12 cycles in 60 years. These penetrations would also be exposed to up to one safe shutdown earthquake cycle.

The staff confirmed that the fuel transfer tube bellows were designed for 1,000 cycles when it audited the applicant's vendor records. For those cycles, the bellows combined stress to failure was extracted from a best-fit curve of meridional stress value versus cycle life based on fatigue test data of series of bellows. The staff noted that the total number of cycles to be experienced by the bellows are far less than their design cycles. The staff also noted that Section 3.8.1.1.6, "Containment Penetrations and Attachments," of the UFSAR identifies the assembly of transfer tube and bellows to consist of a stainless steel pipe inside a carbon steel sleeve, where the inner pipe acts as a transfer tube with the outer tube welded to the containment liner. Bellows expansion joints are provided to permit differential movement. The staff further noted that NUREG/CR-6726, "Aging Management and Performance of Stainless Steel Bellows in Nuclear Power Plants," in its "Operating Experience from Nuclear Plant Reliability Data System Data" subchapter, notes that fuel transfer tube bellows failures to have occurred not in the bellows but on their gasket subcomponents. Because of such recorded failures, and even though the bellows are designed in excess of the anticipated thermal, refueling, pressurization, and earthquake based cycles, the applicant, in its response to RAI 3.5.2.2.1.7-1 by letter dated November 21, 2011, revised the LRA (this is discussed in SER Section 3.5.2.2.1, item 7). It instituted a bellows inspection, based on its ASME Code Section XI, Subsection IWE Program and on its 10 CFR Part 50, Appendix J Program to assure the absence of any potential aging effects.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the analysis for the fuel transfer tube bellows remains valid for the period of extended operation.

Additionally, it meets the acceptance criteria in SRP-LR Section 4.6.3.1.1.1 because the bellows have been designed based on actual tests to sustain far more cycles of operation than a projected number; hence, the analysis is valid for the period of extended operation.

4.6.3.3 UFSAR Supplement

LRA Section A3.5.2 provides the UFSAR supplement summarizing the fatigue design of containment penetrations that includes the fuel transfer tube bellows. The staff reviewed LRA Section A3.5.2, "Fatigue Design of Containment Penetrations," consistent with the review procedures in SRP-LR Section 4.6.3.1.1.3. These procedures state that, for the fatigue of the containment penetrations (other than the fuel transfer bellows), the applicant's proposed AMP needs to be reviewed on a case-by-case basis to ensure that the effects of aging on the intended function(s) of the components are adequately managed for the period of extended operation. For the case of the fuel transfer tubes fatigue, SRP-LR Section 4.6.3.1.1.1 states that the number of assumed transients used in the existing CUF calculations for the current operating term has been compared to the extrapolation to 60 years of operation of the number of operating transients experienced to date. The comparison confirmed that the number of transients in the existing analyses would not be exceeded during the period of extended operation.

Based on its review of the UFSAR supplement, the staff finds that it meets the acceptance criteria in SRP-LR Section 4.6.2.1.1.1 and SRP-LR Section 4.6.2.1.1.3. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA of the fatigue design of the containment penetrations, as required by 10 CFR 54.21(d).

4.6.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the TLAA for the fuel transfer tube bellows remains valid during the period of extended operation. The staff also finds, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions of the containment penetrations will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7 Other Plant-Specific Time-Limited Aging Analyses

4.7.1 Load Cycle Limits of Cranes, Lifts, and Fuel Handling Equipment Designed to CMAA-70

4.7.1.1 Summary of Technical Information in the Application

LRA Section 4.7.1 describes the applicant's TLAA for load cycle limits of cranes, lifts, and fuel handling equipment designed to CMAA-70. LRA Table 4.7-1 summarizes the estimated maximum number of significant crane lifts for each machine. The applicant stated that the number of significant lifts for each machine per refueling outage is estimated from the UFSAR Section 9.1.4.2.2 description of refueling operations. In addition, the estimated number of lifts is multiplied by a factor of 1.5 to account for non-refueling lifts. The applicant further stated that based on an 18-month refuel cycle, approximately 27 refuel cycles are expected over a 40-year plant design life, or about 40 refuel cycles in a 60-year design life.

<u>New Fuel Handling Area Overhead Crane</u>. The applicant stated that the new fuel handling area overhead crane is designed to handle fuel assemblies and their shipping containers in the new fuel handling area.

<u>Cask Handling Overhead Crane</u>. The applicant stated that the cask handling overhead crane is designed to three primary operations: (1) transfer the fuel cask from the bed of the transport vehicle to the cask decontamination area, (2) lower the cask into the dry cask handling system transporter tank following inspection or walkdown, and (3) return the cask to the transport vehicle following fuel loading operations.

<u>Fuel Handling Building Overhead Crane</u>. The applicant stated that the fuel handling building overhead crane is designed to five primary operations: (1) transfer the new fuel shipping containers from the transport vehicle to the new fuel handling area, (2) transfer the new fuel assemblies from the new fuel handling area to the new fuel storage area or to the new fuel elevator, (3) transfer the spent fuel shipping cask head from the cask to its storage shelf in the cask loading pool, and to lower the head onto the cask, (4) replace the safety injection and containment spray pumps, and (5) perform general service and maintenance operations as required.

<u>Containment Polar Crane</u>. The applicant stated that the containment polar crane is evaluated to refueling and fuel handing operations. It is also used for construction, maintenance, and repair

operations as needed. The applicant also stated that this crane is classified as non-nuclear safety (NNS) class since it neither provides nor supports any system safety function.

Refueling Machine. The applicant stated that the refueling machine is designed to transfer fuel from one location to another.

Fuel Handling Machine. The applicant stated that the fuel handling machine is designed to handle fuel assemblies and core components in the spent fuel pool by means of handling tools suspended from the hoist. The applicant also stated that the fuel handling machine has a two-step magnetic control for the bridge and hoist.

New Fuel Elevator. The applicant stated that the new fuel elevator is designed to lower a new fuel assembly into the fuel transfer canal and can be used to raise a new or spent fuel assembly.

Fuel Transfer System. The applicant stated that the fuel transfer system is designed to transfer fuel between the reactor containment building and the fuel handling building. The applicant also stated that a hydraulically actuated lifting arm (upender) at each end of the transfer tube is used to take the fuel from a vertical position to a horizontal position to pass through the transfer tube and then back into the vertical position for placement.

Disposition. The applicant dispositioned the load cycle limits of cranes, lifts, and fuel handling equipment designed to CMAA-70 TLAA in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid during the period of extended operation.

4.7.1.2 Staff Evaluation

The staff reviewed LRA Section 4.7.1 and the load cycle limits of cranes, lifts, and fuel handling equipment designed to CMAA-70 TLAA to confirm, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses remain valid during the period of extended operation.

The staff reviewed the applicant’s TLAA and the corresponding disposition, consistent with the review procedures in SRP-LR Section 4.7.3.1.1, which states that the existing analyses should be shown to be bounding even during the period of extended operation. The SRP-LR also states that the applicant describes the TLAA with respect to the objectives of the analysis; assumptions used in the analysis; and conditions, acceptance criteria, relevant aging effects, and intended functions. The applicant shows that conditions and assumptions used in the analysis already address the relevant aging effects for the period of extended operation, and acceptance criteria are maintained to provide assurance that the intended functions are maintained for renewal.

New Fuel Handling Area Overhead Crane. The staff reviewed LRA Section 4.7.1 and UFSAR Section 9.1.4.2 and found that the new fuel handling area overhead crane is a 5-ton crane designed to CMAA-70, Class A1. LRA Table 4.7-1 indicates that the new fuel handling area overhead crane is designed to 100,000 cycles.

The estimated maximum number of significant crane lifts for the new fuel handling area overhead crane projected for 40 years, based on 27 refueling outages, was 5,346. The estimated maximum number of significant crane lifts projected for 60 years, based on 40 refueling outages, is 8,019. This is significantly less than the 100,000 permissible cycles and, therefore, is acceptable.

Cask Handling Overhead Crane. The staff reviewed LRA Section 4.7.1 and UFSAR Section 9.1.4.2 and found that the cask handling overhead crane is a 150-ton crane designed to CMAA-70, Class A1. LRA Table 4.7-1 indicates that the cask handling overhead crane is designed to 100,000 cycles.

LRA Table 4.7-1 shows the estimated maximum number of significant crane lifts for the cask handling overhead crane to be 420 for 40 years based on 10 refuels and 740 for 60 years based on 20 refuels. It is unclear to the staff how these numbers were calculated and why the calculations were based on 10 refuels and 20 refuels for the 40-year and 60-year cycles, respectively. Therefore, in a letter dated August 15, 2011, the staff issued RAI 4.7.1-1, requesting that the applicant provide the basis for the estimated number of significant crane lifts for both a 40 and 60-year design life. The staff also asked the applicant to explain why the number of refuel cycles being used in this calculation differs from 27 refuel cycles expected over a 40-year design life and 40 refuel cycles expected over a 60-year design life based on an 18-month refuel cycle, as stated in LRA Section 4.7.1.

In its response dated October 10, 2011, the applicant stated that the number of lifts for the cask handling overhead crane is based on three lifts per cask and seven casks per refueling outage, which equals 21 lifts per unit per refueling outage. In addition to the refueling outage lifts, the 40-year and 60-year cycles include an estimated 100 construction lifts.

In the applicant’s response regarding the number of refuels used in the cask handling overhead crane calculation, the applicant stated that the number of refueling outages differs because cask loading is assumed to begin in year 30 of plant operation. The staff determined that additional clarification was needed; therefore, the staff participated in a teleconference with the applicant on November 17, 2011, to discuss the response. Based on the discussion, the applicant agreed to revise their response to RAI 4.7.1-1.

It its revised response dated December 7, 2011, the applicant clarified that once cask loading is commenced, the number of fuel assemblies moved to dry cask storage is equal to the number of new fuel assemblies received each refueling outage. Therefore, the number of casks loaded—and, hence, the number of cask handling crane lifts—is dependent on the number of refueling outages. The applicant stated that the calculated number for each outage was multiplied by 1.5 for conservatism, resulting in the estimated 32 significant lifts per refueling outage.

The applicant further clarified that the number of refueling outages assumed in the lift estimate for the cask handling overhead crane differs from the 27 refueling cycles expected over a 40-year design life and the 40 refueling cycles expected over a 60-year design life assumed in the estimate for the other cranes because cask loading is assumed to begin in year 30 of plant operation. The applicant also clarified that the 40-year estimate was based on a rounded up number of 10 refueling outages, from the actual 6.67 refueling outages, to simplify the calculation.

The staff finds the applicant’s response acceptable because the estimated maximum number of significant crane lifts for the cask handling overhead crane does not exceed the design lifts for the crane. The estimated maximum number of significant crane lifts for the cask handling overhead crane projected for 40 years, based on 10 refueling outages, was 420. The estimated maximum number of significant crane lifts projected for 60 years, based on 20 refueling outages, is 740. This is significantly less than the 100,000 permissible cycles; therefore, it is acceptable.

Fuel Handling Building Overhead Crane. The staff reviewed LRA Section 4.7.1 and UFSAR Section 9.1.4.2 and found that the fuel handling building overhead crane is a 15/2-ton (15-ton main hook and 2-ton auxiliary hook) crane designed to CMAA-70, Class A1. LRA Table 4.7-1 indicates that the fuel handling building overhead crane is designed to 100,000 cycles.

The estimated maximum number of significant crane lifts for the fuel handling building overhead crane projected for 40 years, based on 27 refueling outages, was 12,636. The estimated maximum number of significant crane lifts projected for 60 years, based on 40 refueling outages, is 18,954. This is significantly less than the 100,000 permissible cycles; therefore, it is acceptable.

Containment Polar Crane. The staff reviewed LRA Section 4.7.1 and UFSAR Section 9.1.4.2 and found that the containment polar crane is a 310/15-ton (310-ton main hook and 15-ton auxiliary hook) crane designed to CMAA-70, Class A1. LRA Table 4.7-1 indicates that the containment polar crane is designed to 200,000 cycles.

LRA Table 4.7-1 shows the estimated maximum number of significant crane lifts for the containment polar crane to be 2,411 for 40 years, and 3,542 for 60 years based on an 18-month refuel cycle. It is unclear to the staff how these numbers were calculated; therefore, by letter dated August 15, 2011, the staff issued RAI 4.7.1-2, requesting that the applicant show how the estimated maximum number of significant crane lifts for the 40-year and 60-year cycles were calculated, based on the estimated 54 lifts per refuel.

In its response dated October 10, 2011, the applicant stated that the number of lifts for the polar crane is based on the following refueling lifts: reactor head (2 lifts per refueling); reactor upper internals (2 lifts per refueling); and maintenance and repair operations (50 lifts per refueling). The 40-year and 60-year estimates also include 9 and 13 lower internals lifts, respectively (once every three refueling), and an additional 150 construction lifts. The applicant further stated that, while reviewing this RAI, a calculation error was found in LRA Table 4.7-1 for the number of polar crane lifts. This correction does not change the disposition of the crane TLAA evaluation.

The staff finds the applicant’s response acceptable because the estimated maximum number of significant crane lifts for the polar crane does not exceed the design lifts for the crane. The estimated maximum number of significant crane lifts projected for 40 years, based on 27 refueling outages, was 2,355, and the estimated maximum number of significant crane lifts projected for 60 years, based on 40 refueling outages, is 3,416. This is significantly less than the 200,000 permissible cycles; therefore, it is acceptable.

Refueling Machine. The staff reviewed LRA Section 4.7.1 and UFSAR Section 9.1.4.2 and found that the refueling machine is a rectilinear bridge and trolley crane with a vertical mast extending down into the refueling cavity. In general, the crane structure is considered in the Class A1, “Standby Service,” as defined by CMAA-70. LRA Table 4.7-1 indicates that the refueling machine is designed to 100,000 cycles.

The estimated maximum number of significant crane lifts for the new fuel handling area overhead crane projected for 40 years, based on 27 refueling outages, was 17,658. The estimated maximum number of significant crane lifts projected for 60 years, based on 40 refueling outages, is 26,487. This is significantly less than the 100,000 permissible cycles; therefore, it is acceptable.

Fuel Handling Machine. The staff reviewed LRA Section 4.7.1 and UFSAR Section 9.1.4.2 and found that the fuel handling machine consists of an electric monorail hoist carried on a wheel-mounted bridge. In general, the crane structure is considered in the Class A1, “Standby Service,” as defined by CMAA-70. LRA Table 4.7-1 indicates that the fuel handling machine is designed to 100,000 cycles.

The estimated maximum number of significant crane lifts for the new fuel handling area overhead crane projected for 40 years, based on 27 refueling outages, was 30,186. The estimated maximum number of significant crane lifts projected for 60 years, based on 40 refueling outages, is 45,279. This is less than the 100,000 permissible cycles; therefore, it is acceptable.

New Fuel Elevator. The staff reviewed LRA Section 4.7.1 and UFSAR Section 9.1.4.2 and found that the new fuel elevator consists of a box-shaped elevator assembly with its top end open designed to meet the requirements of CMAA-70. LRA Table 4.7-1 indicates that the new fuel elevator is designed to 100,000 cycles.

The estimated maximum number of significant crane lifts for the new fuel handling area overhead crane projected for 40 years, based on 27 refueling outages, was 2,673. The estimated maximum number of significant crane lifts projected for 60 years, based on 40 refueling outages, is 4,010. This is less than the 100,000 permissible cycles; therefore, it is acceptable.

Fuel Transfer System. The staff reviewed LRA Section 4.7.1 and UFSAR Section 9.1.4.2 and found that the fuel transfer system designed to CMAA-70 includes an underwater, electric-motor-driven transfer car that runs on tracks extending from the refueling canal in the RCB, through the fuel transfer tube, and into the fuel transfer canal in the FHB. LRA Table 4.7-1 indicates that the fuel handling machine is designed to 100,000 cycles.

The estimated maximum number of significant crane lifts for the fuel transfer system projected for 40 years, based on 27 refueling outages, was 17,658. The estimated maximum number of significant crane lifts projected for 60 years, based on 40 refueling outages, is 26,487. This is less than the 100,000 permissible cycles; therefore, it is acceptable.

Summary. The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses for the load cycle limits of cranes, lifts, and fuel handling equipment designed to CMAA-70 remain valid during the period of extended operation.

Additionally, it meets the acceptance criteria in SRP-LR Section 4.7.2 because the applicant has demonstrated that the analyses for load cycle limits of cranes, lifts, and fuel handling equipment designed to CMAA-70 remain valid for the period of extended operation pursuant to 10 CFR 54.21(c)(i). Additionally, the applicant’s UFSAR supplement meets the requirements of 10 CFR 54.21(d).

4.7.1.3 UFSAR Supplement

LRA Section A3.6.1 provides the UFSAR supplement summarizing the load cycle limits of cranes, lifts, and fuel handling equipment designed to CMAA-70. The staff reviewed LRA Section A3.6.1, consistent with the review procedures in SRP-LR Section 4.7.3.2, which states that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of each TLAA. SRP-LR Section 4.7.3.2 also states that each summary description is reviewed to confirm that it is appropriate, such that later changes can be controlled by 10 CFR 50.59 and that the description should contain information that the TLAAs have been dispositioned for the period of extended operation.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.7.3.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address load cycle limits of cranes, lifts, and fuel handling equipment designed to CMAA-70, as required by 10 CFR 54.21(d).

4.7.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses for the load cycle limits of cranes, lifts, and fuel handling equipment designed to CMAA-70 remain valid during the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.2 Inservice Flaw Growth Analyses that Demonstrate Structural Stability for 40 years

4.7.2.1 Summary of Technical Information in the Application

LRA Section 4.7.2 states that inservice flaw growth is identified in NUREG-1800 as a potential TLAA. The applicant searched the CLB and did not identify any flaws evaluated for the remaining life of the plant other than those discussed elsewhere in the LRA such as the flaw growth analysis of the half-nozzle repair on the Unit 1 BMI nozzles (this is a TLAA, which will remain valid for the period of extended operation and is dispositioned in accordance with 10 CFR 54.21(c)(1)(i), as discussed in LRA Section 4.3.2.1) and the pressurizer structural weld overlay repairs and mitigations performed on Unit 1 and 2 pressurizer nozzles. The flaw growth analysis does not qualify cracks for the life of the plant but only the 10-year inspection interval. Therefore, this analysis is not a TLAA in accordance with 10 CFR 54.3(a), Criterion 3, as discussed in LRA Section 4.3.2.4.

4.7.2.2 Staff Evaluation

The staff reviewed LRA Section 4.7.2 to confirm that the TLAA of inservice flaw growth analysis of piping in scope for the LRA will meet 10 CFR 54.21(c)(1). The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with the review procedures in SRP-LR Section 4.7.3, which states that the review of the TLAA provides assurance that the aging effect is properly addressed through the period of extended operation. The staff's review on the flaw growth analysis of the half-nozzle repair for the Unit 1 BMI nozzle is discussed in Section 4.3.2.1 of this safety evaluation. The staff's review on the flaw growth analysis of the overlaid Alloy 82/182 welds at the pressurizer surge line nozzles is discussed in Section 4.3.2.4 of this safety evaluation.

In RAI 4.7.2-1, the staff asked the applicant to discuss the sources that have been searched to obtain the information on the flaw growth analyses. The staff also asked the applicant to discuss whether there are recordable indications or flaws that have remained inservice in the piping without a flaw evaluation for pipes within the scope of LRA and discuss how these flaws will be monitored to the end of 60 years. By letter dated May 12, 2011, the applicant responded that, to identify flaws in the components, it searched the UFSAR, TSs, the NRC SERs for the original operating licenses, subsequent NRC SEs, and STPNOC and NRC docketed licensing correspondence.

Based on its search, the applicant stated that besides the flaws discussed above, it identified a flaw of a small active leak at the top of the shell to base plate weld in the Unit 1 refueling water storage tank (RWST). The applicant submitted for NRC review and approval Relief Request RR-ENG-33 to allow the flaw to remain in service for one fuel cycle in a letter dated February 22, 2000 (ADAMS Accession No. ML003686976.) The applicant determined that the fatigue flaw growth was insignificant (growth of 1 in. for 100,000 fill/drain cycles). The NRC authorized Relief Request RR-ENG-33, in letter dated June 22, 2000, to allow Unit 1 to operate with the flaw in place for one fuel cycle until the tank could be inspected (ADAMS Accession No. ML003725735).

Subsequently, the applicant inspected the RWST and found no evidence of base plate or sidewall cracking inside the tank. Based on those inspection results and a large allowable flaw length of 63.6 in., the NRC staff concluded that Unit 1 can continue to be operated, subject to future inspections as required by ASME Code, Section XI, which will monitor the leak to the end of 60 years. The NRC's safety evaluation is documented in a letter dated December 14, 2001 (ADAMS Accession No. ML013460299).

The applicant stated that the safety evaluation of RR-ENG-33 found that the fatigue crack growth analysis is not required to be considered in the final safety determination; thus, it is not a TLAA in accordance with 10 CFR 54.3(a) Criterion 4. The staff finds that the RWST and associated flaw will be periodically inspected in accordance with the ASME Code, Section XI. As such, the staff determines that the flaw in the RWST does not have to be considered in TLAA, in accordance with 10 CFR 54.3(a), because any potential aging effect on the RWST will be monitored by the periodic inspections.

4.7.2.3 UFSAR Supplement

LRA Section A3.6.2 provides the UFSAR supplement summarizing description of its TLAA of the flaw growth analyses of piping in the scope of the LRA. The staff reviewed LRA Section A3.6.2, consistent with the review procedures in SRP-LR Section 4.7.3.2, which states that the staff confirms that the UFSAR supplement includes a summary description of the evaluation of each TLAA. Based on its review of the UFSAR supplement, the staff finds that it meets the acceptance criteria in SRP-LR Section 4.7.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA of the flaw growth analyses of piping in the scope of the LRA, as required by 10 CFR 54.21(d).

4.7.2.4 Conclusion

The staff's conclusion on the flaw growth analysis of the half nozzle repair on the Unit 1 BMI nozzle is discussed in Section 4.3.2.1 of this safety evaluation. The staff's conclusion on the flaw growth analysis of the overlaid Alloy 82/182 welds at the pressurizer surge line nozzles is discussed in Section 4.3.2.4 of this safety evaluation. The staff concludes that the flaw in the RWST is not a TLAA, in accordance with 10 CFR 54.3(a), because the RWST will be inspected periodically in accordance with the ASME Code, Section XI. The inspection will monitor the flaw growth and monitor the aging effects on the RWST. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation of the flaw growth calculations of piping in the scope of the LRA, as required by 10 CFR 54.21(d).

4.7.3 TLAA for the Corrosion Effects in the Essential Cooling Water (ECW) System

4.7.3.1 Summary of Technical Information in the Application

LRA Section 4.7.3 describes the applicant's analyses of corrosion rate in the ECW system. The applicant's revised response to NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," dated June 23, 1992, stated that the corrosion rate in the ECW system was 0.6 mil/year, which would result in a wall thickness loss less than the design limit of 40 mils during the 40 years of plant operation.

The applicant dispositioned the corrosion effects in the ECW System TLAA in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed for the period of extended operation.

4.7.3.2 Staff Evaluation

The staff reviewed LRA Section 4.7.3 and the corrosion effects in the ECW system TLAA to confirm, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed for the period of extended operation.

The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with the review procedures in SRP-LR Section 4.7.3.1.3, which states that the applicant is to adequately manage the effects of aging on the intended functions with an AMP, consistent with the CLB for the period of extended operation.

The staff noted that corrosion in the ECW system was to be managed with the Open-Cycle Cooling Water System Program. The staff also noted that this program, as originally described in the LRA, consisted of visual inspections to detect loss of material in the ECW system. It was unclear to the staff how the visual inspection techniques in the Open-Cycle Cooling Water System Program would be capable of monitoring component wall thickness. By letter dated September 21, 2011, the staff issued RAI 4.7.3-1 requesting that the applicant state how the visual inspections would be capable of ensuring that the corrosion in the ECW system will not exceed the 40 mil design limit in the period of extended operation or propose an alternate methodology for ensuring the design limit is not exceeded.

In its response dated November 21, 2011, the applicant stated that when visual inspections identify corrosion, thickness measurements are taken as part of the Corrective Action Program. The staff found the response unacceptable because it lacked sufficient information to conclude that visual inspections alone would be capable of prompting followup thickness measurements. By letter dated December 14, 2011, the staff issued followup RAI 4.7.3-2 requesting that the applicant state how visual inspections would be capable of detecting a 40-mil corrosion loss, or alternatively, state what augmented inspection techniques will be used to detect loss of material. A teleconference was held with the applicant on January 4, 2012, to clarify the staff's concerns in the followup RAI.

In its response dated February 6, 2012, the applicant stated that the 0.6 mil/year corrosion rate was not used in a plant analysis for making a safety determination for the ECW system; thus, the corrosion effects in the ECW system were incorrectly identified as a TLAA in the LRA. The applicant also stated that Section 4.7.3 would be deleted from the LRA. A teleconference was held with the applicant on February 9, 2012, to discuss how the applicant concluded that the corrosion rate analysis was not used in a safety determination, given that the analysis was included in the applicant's revised response to NRC Generic Letter 89-13 to provide justification for discontinuing the use of corrosion inhibitors in the ECW system. In response to the discussion, the applicant stated that it would provide a revised response to RAI 4.7.3-2.

In its response dated March 5, 2012, the applicant re-evaluated the TLAA and determined that it remains valid for the period of extended operation. The applicant stated that the aging effects would be managed using volumetric inspections in the Open-Cycle Cooling Water System Program, dispositioning the TLAA in accordance with 10 CFR 54.21(c)(1)(iii). The applicant also stated that wall thinning would be monitored for a minimum of 25 locations, in areas considered to have the highest corrosion rate, prior to the period of extended operation. The applicant further stated that subsequent inspections would be scheduled prior to the piping reaching minimum wall thickness, at which point an engineering analysis would be performed to determine if acceptable safety margin exists for continued operation. If an acceptable safety margin does not exist, the pipe would be isolated, repaired, or replaced. The applicant revised LRA Section A1.9, Section B2.1.9, and Commitment No. 4 to account for the changes in the Open-Cycle Cooling Water System Program. The applicant also added an item to LRA Table 3.3.2-4 for the disposition of the TLAA.

The staff finds the applicant response acceptable because the volumetric wall thickness measurements in the Open-Cycle Cooling Water System Program, performed for a minimum of 25 locations in areas considered to have the highest corrosion rate, are capable of detecting wall thinning prior to reaching the minimum wall thickness. The staff noted that, as described in the applicant's RAI response dated February 6, 2012, the 40-mil design limit was originally added to the minimum pipe wall thickness to account for potential reductions in wall thickness due to factors such as erosion and corrosion. The staff also noted that the proposed volumetric inspections will be capable of directly monitoring such wall thickness reductions as the minimum wall thickness is approached; thus, the inspections are capable of detecting degradation prior to loss of intended function. The staff's concerns described in RAIs 4.7.3-1 and 4.7.3-2 are resolved.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions of the corrosion effects in the ECW system TLAA will be adequately managed for the period of extended operation.

4.7.3.3 UFSAR Supplement

LRA Section A3.6.3 provides the UFSAR supplement summarizing the ECW system corrosion rate analysis and the disposition of this TLAA to manage corrosion with the Open-Cycle Cooling Water System Program. The staff reviewed LRA Section A3.6.3, consistent with the review procedures in SRP-LR Section 4.7.3.2, which states that the applicant should provide a summary description of each TLAA that contains information on how the TLAA was dispositioned for the period of extended operation.

Based on its review of the UFSAR supplement, as modified by RAI response dated March 5, 2012, the staff finds it meets the acceptance criteria in SRP-LR Section 4.7.3.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the corrosion effects in the ECW system TLAA, as required by 10 CFR 54.21(d).

4.7.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions of the corrosion effects in the ECW system TLAA will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.4 Reactor Vessel Underclad Cracking Analysis

4.7.4.1 Summary of Technical Information in the Application

LRA Section 4.7.4, as amended by letter dated March 29, 2012, describes the applicant’s TLAA for underclad cracking of the RPV components fabricated from SA-508, Class 2, forging materials. The applicant stated that the phenomenon of underclad cracking was originally addressed in the design basis though the implementation of welding practices that conformed to the crack-mitigation strategy and position in NRC RG 1.43, “Control of Stainless Steel Weld Cladding of Low Alloy Steel Components.”

The applicant stated that, in Topical Report No. WCAP-15338-A, Westinghouse evaluated and demonstrated that the vessel integrity is maintained in the presence of underclad cracks. The phenomenon of underclad cracking is only applicable to RPV alloy steel components that were fabricated from SA-508, Class 2, alloy steel forging materials that were manufactured to a coarse grain practice and clad by high-heat-input submerged arc welding process. The only RPV alloy steel components that are fabricated from SA-508, Class 2, forging materials are the RPV nozzles and the RPV flanges. The applicant stated that the generic fatigue flaw growth analysis in WCAP-15338-A is a time-dependent analysis that meets the definition of a TLAA.

The applicant dispositioned the TLAA for underclad cracking of RPV components in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

4.7.4.2 Staff Evaluation

The staff reviewed LRA Section 4.7.4 and the TLAA for underclad cracking of RPV components to confirm pursuant to 10 CFR 54.21(c)(1)(i), that the analysis remains valid during the period of extended operation.

The staff reviewed the applicant’s TLAAs for underclad cracking of RPV components and the corresponding disposition of 10 CFR 54.21(c)(1)(i), consistent with the review procedures in SRP-LR Section 4.3.3.1.5.1. These procedures state that the operating cyclic experiences, and a list of the assumed cycles used in the existing analyses, are reviewed to ensure that the number of assumed cycles would not be exceeded during the period of extended operation.

The staff noted that non-proprietary Westinghouse Report No. WCAP-15338 provides a fracture toughness and flaw growth analysis for underclad cracks that are postulated in the internal cladding of SA-508 Class 2 alloy steel components in Westinghouse-design RPVs. The staff noted that the flaw growth analysis is based on ASME Code Section XI, Appendix A, which involves fatigue flaw growth methods that evaluate potential RPV underclad flaws over a 60-year licensed operating period. The staff’s review of the fracture toughness and flaw growth analyses in WCAP-15338 is documented in an SE to the Westinghouse Owners Group (WOG) dated October 15, 2001.

The staff noted that WCAP-15338-A is applicable to two-loop and four-loop Westinghouse reactor designs; therefore, WCAP-15338-A is applicable to the applicant's reactor design, which is a four-loop Westinghouse Electric designed PWR. The generic safety and flaw analysis in WCAP-15338 evaluated the impact of 60 years of operation on the growth of postulated underclad cracks initiated in the internal cladding of Westinghouse designed RPV components made from SA-508 Class 2 alloy steel forged materials. In the staff's SE on WCAP-15338-A, two renewal applicant action items for PWR applicants that reference WCAP-15338-A in the LRA were identified. The first renewal action item states that for applicant's with Westinghouse two-loop and four-loop designed PWRs, the license renewal applicant should demonstrate that the transients for normal, upset, emergency, faulted, and PTS conditions assessed in WCAP-15338 are bounding for the plant-specific transients for these conditions; otherwise, the applicant will perform similar Section XI flaw evaluations using their plant-specific transients to demonstrate that the RPVs with underclad cracks are acceptable though 60 years of licensed operation. The second renewal action item states the license renewal applicants referencing WCAP-15338-A should provide a summary description of the TLAA evaluation in the UFSAR supplement. By letter dated March 29, 2012, the LRA was revised to include LRA Section A.3.6.5, which is the UFSAR supplement for the TLAA related to underclad cracking of RPV components. The staff's review of LRA Section A.3.6.5 is documented in SER Section 4.7.4.3.

The staff noted that, in Section 5.4 of WCAP-15338-A, Westinghouse evaluated the fatigue induced crack growth that would occur in postulated flaws that have 2:1, 6:1, and 100:1 length to depth aspect ratios. In addition, it was noted that Westinghouse considered the entire set of design basis transients for Westinghouse designed plants to assess the impact of each design basis transient on the postulated flaw sizes in the analysis. The staff verified that Westinghouse calculated the crack growth associated with limiting number of cycles for each Westinghouse design basis transient over 60-years of operation by adding the crack growth increment to the original postulated flaw size and then repeating the process until all transient cycles have been accounted for in the final analyzed flaw size.

The staff also verified that the design basis transients for the applicant are described in LRA Table 4.3-2 and that the number of cycles for design transients analyzed for in WCAP-15338-A are bounding for the number of cycles projected for the applicant's units through 60 years of operation. Since the Westinghouse analysis incorporates the entire set of design basis transients for a four-loop Westinghouse-designed nuclear reactor, the staff finds that the applicant has demonstrated that the generic fatigue flaw growth analysis bounds the set of design basis transients for the applicant's units through 60-years of operation.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses for underclad cracking of the RPV components remain valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.3.3.1.5.1 because the applicant and the Westinghouse flaw growth analysis for underclad cracks in RPV components made SA-508 Class 2 forging materials demonstrated that the full set of design transients for 60-years of operation were considered and will not be exceeded during the period of extended operation.

4.7.4.3 UFSAR Supplement

LRA Section A3.6.5, as amended by letter dated March 29, 2012, provides the UFSAR supplement summarizing the TLAA for underclad cracking of the RPV components. The staff reviewed LRA Section A3.6.5, consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the reviewer confirms that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA for underclad cracking of the RPV components, as required by 10 CFR 54.21(d).

4.7.4.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses for underclad cracking of the RPV components remain valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.5 Reactor Coolant Pump Flywheel Crack Growth Analysis

4.7.5.1 Summary of Technical Information in the Application

LRA Section 4.7.5 describes the applicant’s TLAA for RCP flywheel fatigue crack growth analyses. The applicant stated that UFSAR Section 5.4.1.5.2 describes RCP flywheel design and its compliance with RG 1.14 and that RCP flywheel inspections are included in the STP ISI Program and are required by STP TS 4.4.10.

To reduce the inspection frequency and scope, STP amended its initial compliance with RG 1.14 by implementing Westinghouse Topical Report WCAP-14535-A, “Reactor Coolant Pump Motor Flywheel Inspection Elimination,” which supports the relaxation of inspections required by RG 1.14, Positions C.4.b(1) and (2).

The applicant stated that the topical report, Westinghouse Topical Report WCAP-14535-A, “Reactor Coolant Pump Flywheel Inspection Elimination,” provided an engineering basis for elimination of RCP flywheel inservice inspection requirements for all operating Westinghouse plants and certain Babcock and Wilcox plants. Fatigue crack growth analyses that are included in the WCAP-14535-A report have been identified as a TLAA. The applicant stated that WCAP-14535-A performed a Monte-Carlo simulation to evaluate the probability of failure over the period of extended operation for all operating Westinghouse plants. It demonstrated that the flywheel design has a high structural reliability with a very high flaw tolerance and negligible flaw crack extension over a 60-year service life (assumed 6,000 pump starts). Therefore, any potential crack growth from an existing flaw would be minimal, and the analysis in the WCAP-14535-A report remains valid for the period of extended operation.

The applicant dispositioned the flywheel TLAA in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid during the period of extended operation.

4.7.5.2 Staff Evaluation

SRP-LR Section 4 does not list RCP flywheel fatigue crack growth analyses as TLAAs that are generic to industry LRAs. As a result, the staff reviewed LRA Section 4.7.5 against the acceptance guidance in SRP-LR Section 4.7.5.1 for disposition of a plant-specific TLAA in accordance with 10 CFR 54.21(c)(1)(i). The staff reviewed LRA Section 4.7.5 to confirm, pursuant to 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

The staff noted that RG 1.14, Revision 1, "Reactor Coolant Pump Flywheel Integrity" (August 1976) provides the staff's recommended acceptance criteria for material and minimum fracture toughness properties of SA 508, Classes 2 and 3, materials and SA 533 Grade B, Class 2, materials used in the fabrication of U.S. RCP flywheels. RG 1.14, Revision 1, also provides guidelines for performing structural integrity assessments of the RCP flywheels in U.S. light-water reactors (LWRs), including assessments for ensuring the integrity of the flywheels against unacceptable fatigue-induced crack growth failures.

The staff noted that the applicant is relying on the flaw growth analysis in the WCAP-14535-A (ADAMS Accession No. 9601290303) as the TLAA for the RCP flywheels. The staff confirmed that the NRC endorsed the methodology and results in this WCAP report in an SE dated September 12, 1996 (ADAMS Accession No. 9609230010). However, in the conclusion section of the SE (Section 4.0), the staff concluded that that the inspections of the RCP flywheels should be performed even if all of the recommendations of RG 1.14, Revision 1, were met and that the inspections of the RCP flywheels should not be eliminated.

The staff issued RAI 4.7.5-1, requesting that the applicant describe the past examinations for the RCP flywheels and explain how those results justify the use of WCAP-14535-A. The staff also asked the applicant to clarify whether the safety basis in the TLAA for the RCP flywheels is being used to justify elimination of the RCP flywheel examinations altogether or whether the applicant intends to continue the ISIs of the RCP flywheels, consistent the NRC's SE on WCAP-14535-A, dated September 12, 1996. If ISIs will be performed during the period of extended operation, the staff also asked the applicant to justify what type of examinations will be performed on the RCP flywheels during the period of extended operation and note the frequency that will be used for the examinations. Otherwise, the applicant was asked to justify its basis for discontinuing the ISIs of the RCP flywheels if ISIs will be discontinued during the period of extended operation.

The applicant's March 12, 2012, response indicated that STP Unit 1 RCP flywheels have been inspected four times, and STP Unit 2 RCP flywheels have been inspected five times. The most recent ultrasonic (UT) examinations were conducted in fall 2009 and fall 2008 for STP Units 1 and 2, respectively.

The applicant stated that no unacceptable indications have been found in any of the required inspections. In addition, the applicant stated that during the period of extended operation, STP will continue the surface and volumetric inspections of the RCP flywheels on the required interval.

In summary, the staff finds the applicant's response to RAI 4.7.5-1, and the applicant's claim that the RCP flywheels will maintain their structural integrity during the period of the extended operation, acceptable for the following reasons:

- WCAP-14535-A performed a Monte-Carlo simulation to evaluate the probability of failure over the period of extended operation for all operating Westinghouse plants, demonstrating that the RCP flywheel design has a high structural reliability with a very high flaw tolerance and negligible flaw crack extension over a 60-year service life (assumed 6,000 pump starts).
- WCAP-14535-A has been endorsed for use in the staff's SE of September 12, 1996.

- Future inspections will be performed once every 10 years.
- In accordance with 10 CFR 54.21(c)(1)(i), the current analysis has been demonstrated to remain valid for the period of extended operation.

The staff's concerns described in RAI 4.7.5-1 are resolved.

4.7.5.3 UFSAR Supplement

LRA Section A3.6.4 provides the UFSAR supplement summary description of the applicant's TLAA evaluation of the RCP flywheel fatigue crack growth analysis. The staff reviewed LRA Section A3.6.4, consistent with the review procedures in SRP-LR Section 4.7.3.2, which state that the reviewer should confirm that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of each TLAA. Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.7.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the RCP flywheel fatigue crack analysis, as required by 10 CFR 54.21(d).

4.7.5.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that for RCP flywheel fatigue crack analyses, the WCAP-14535-A analysis remains valid for the period of extended operation and applicable to STP, Units 1 and 2. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.8 <u>Conclusion for Time-Limited Aging Analyses</u>

The staff reviewed the information in LRA Section 4, "Time-Limited Aging Analyses." On the basis of its review, the staff concludes that the applicant has provided an adequate list of TLAAs, as defined in 10 CFR 54.3. Furthermore, the staff concludes that the applicant demonstrated that the TLAAs will remain valid for the period of extended operation, as required by 10 CFR 54.21(c)(1)(i); that the TLAAs have been projected to the end of the period of extended operation, as required by 10 CFR 54.21(c)(1)(ii); or that the effects of aging on the intended functions will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(c)(1)(iii). The staff also reviewed the UFSAR supplement for the TLAAs and found that the UFSAR supplement contains descriptions of the TLAAs sufficient to satisfy the requirements of 10 CFR 54.21(d). In addition, the staff concludes that one plant-specific exemption is in effect that is based on TLAAs and that the applicant has provided an adequate evaluation that justifies the continuation of this exemption for the period of extended operation, as required by 10 CFR 54.21(c)(2).

With regard to these matters, the staff concludes that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB and that any changes made to the CLB, in order to comply with 10 CFR 54.21(c), are in accordance with the Atomic Energy Act of 1954 and NRC regulations.

SECTION 5

REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

In accordance with Title 10, Part 54, of the *Code of Federal Regulations* (10 CFR Part 54), the Advisory Committee on Reactor Safeguards (ACRS) will review the license renewal application (LRA) for South Texas Project (STP), Units 1 and 2. The ACRS Subcommittee on Plant License Renewal will continue its detailed review of the LRA after this safety evaluation report (SER) is issued. STP Nuclear Operating Company (the applicant) and the staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff) will meet with the subcommittee and the full committee to discuss issues associated with the review of the LRA.

After the ACRS completes its review of the LRA and SER, the full committee will issue a report discussing the results of the review. An update to this SER will include the ACRS report and the staff's response to any issues and concerns reported.

SECTION 6

CONCLUSION

The staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff) reviewed the license renewal application (LRA) for South Texas Project, Units 1 and 2, in accordance with NRC regulations and NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," Revision 2, dated December 2010. Title 10, Section 54.29, of the *Code of Federal Regulations* (10 CFR 54.29) provides the standards for issuance of a renewed license.

On the basis of its review of the LRA, and pending satisfactory resolution of the open items, the staff determines that the requirements of 10 CFR 54.29(a) have been met.

APPENDIX A

COMMITMENTS FOR LICENSE RENEWAL OF SOUTH TEXAS PROJECT, UNITS 1 AND 2

During the review of the South Texas Project (STP), Units 1 and 2, license renewal application (LRA) by the staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff), STP Nuclear Operating Company (STPNOC) (the applicant) made commitments related to aging management programs (AMPs) and time-limited aging analyses (TLAAs) to manage the aging effects of structures and components (SCs) prior to the period of extended operation. LRA Section A0, "Appendix A Introduction," states that "[LRA] Section A4 [as revised by supplements and RAI responses] contains summary descriptions of license renewal commitments," and that the applicant will incorporate all license renewal commitments into the STP updated final safety analysis report (UFSAR) update following issuance of the renewed operating license in accordance with Title 10, Part 50.71(e) of the *U.S. Code of Federal Regulations* (10 CFR 50.71(e)). The following table lists these commitments, along with the respective implementation schedules and sources of the commitment.

No.	Commitment	Implementation Schedule	LRA Section	Reference Letter & Date
1	Enhance the Water Chemistry Program procedures by doing the following: (NOC-AE-10002607) • 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. • Explain that this increased sampling is used to verify that the desired condition has been achieved, and, when it is achieved, the sampling frequencies are returned to the Electric Power Research Institute (EPRI)-recommended frequencies.	Prior to the period of extended operation	B2.1.2	NOC-AE-10002607, October 25, 2010
2	Enhance the Boric Acid Corrosion Program procedures by doing the following: (NOC-AE-10002607) • State that susceptible components adjacent to potential leakage sources include electrical components and connectors. • State that it is applicable to other materials (such as aluminum and copper alloy) that are susceptible to boric acid corrosion.	Prior to the period of extended operation	B2.1.4	NOC-AE-10002607, October 25, 2010
3	Enhance the Bolting Integrity Program procedures by doing the following: • Conform to the guidance contained in EPRI TR-104213 (NOC-AE-11002750). • 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 (NOC-AE-10002607).	Prior to the period of extended operation	B2.1.7	NOC-AE-10002607, October 25, 2010 NOC-AE-11002750, November 4, 2011
4	Enhance the Open-Cycle Cooling Water System Program procedures by doing the following: • Include visual inspection of the strainer inlet area and the interior surfaces of the adjacent upstream and downstream piping to identify material wastage, dimensional change, discoloration, and discontinuities in surface texture. These inspections will provide visual evidence of loss of material and fouling in the essential cooling water (ECW) system and serve as an indicator of the condition of the interior of ECW system piping components otherwise inaccessible for visual inspection (NOC-AE-10002607). • Include the acceptance criteria for this visual inspection (NOC-AE-10002607). • Require that a minimum of 25 ECW piping locations be measured for wall thickness prior to the period of extended operation. Selected areas will include locations considered to have the highest corrosion rates, such as areas with stagnant flow (NOC-AE-12002809).	Prior to the period of extended operation	B2.1.9	NOC-AE-10002607, October 25, 2010 NOC-AE-12002809, March 5, 2012 NOC-AE-12002825, March 29, 2012 NOC-AE-12002874, July 5, 2012

No.	Commitment	Implementation Schedule	LRA Section	Reference Letter & Date
	• Require an engineering evaluation after each inspection of the aluminum-bronze piping inserted inside the slip-on flange downstream of the component cooling water heat exchanger: (NOC-AE-12002874) – Require that the evaluation will calculate projected wear over the next inspection interval, including a margin of 4 years of wear at the most recent actual yearly wear rate. – Require that repair or replacement, in accordance with the Corrective Action Program, be initiated if the projected wear (which includes a margin of 4 years of wear at the most recent actual yearly wear rate) indicates that the aluminum-bronze piping wall will reduce to a thickness of less than minimum wall thickness. • Require loss of material in piping and protective coating failures be documented in the Corrective Action Program (NOC-AE-12002825). • Require an engineering evaluation be performed when loss of material in piping or protective coating failures is identified (NOC-AE-12002825).			
5	Enhance the Closed-Cycle Cooling Water System Program procedures by doing the following: • Include visual inspection of representative samples of each combination of material and water treatment program at least every 10 years and opportunistically (NOC-AE-10002607) (NOC-AE-11002681) (NOC-AE-11002750). • Include acceptance criteria (NOC-AE-10002607).	Prior to the period of extended operation	B2.1.10	NOC-AE-10002607, October 25, 2010 NOC-AE-11002681, June 16, 2011 NOC-AE-11002750, November 4, 2011
6	Enhance the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program procedures by doing the following: • Inspect crane structural members for loss of material due to corrosion and rail wear. (NOC-AE-10002607).	Prior to the period of extended operation	B2.1.11	NOC-AE-10002607, October 25, 2010
7	Enhance the Fire Protection Program procedures by doing the following: (NOC-AE-10002607) • 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	Prior to the period of extended operation	B2.1.12	NOC-AE-10002607, October 25, 2010

No.	Commitment	Implementation Schedule	LRA Section	Reference Letter & Date
	NUREG-1801. • 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.			
8	Enhance the Fire Water System Program procedures by doing the following: (NOC-AE-10002607) • Include volumetric examinations or direct measurement on representative locations of the fire water system to determine pipe wall thickness. • 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. • Include trending of fire water piping flow parameters recorded during fire water flow tests.	Prior to the period of extended operation	B2.1.13	NOC-AE-10002607 October 25, 2010
9	Enhance the Fuel Oil Chemistry Program procedures by doing the following: • Extend the scope of the program to include the standby diesel generator (SDG) fuel oil drain tanks (NOC-AE-10002607). • Check and remove the accumulated water from the fuel oil drain tanks, day tanks, and storage tanks associated with the SDG, balance of plant (BOP), lighting diesel generator, and fire water pump diesel generators. Include a minimum frequency of water removal from the fuel oil tanks in the procedure (NOC-AE-10002607) (NOC-AE-11002758). • Include 10-year periodic draining, cleaning, and inspection for corrosion of the SDG fuel oil drain tanks, lighting diesel generator fuel oil tank, BOP diesel generator fuel oil day tanks, and diesel fire pump fuel oil storage tanks (NOC-AE-10002607) (NOC-AE-11002758) (NOC-AE-11002763). • Require periodic testing of the lighting diesel generator fuel oil tank and the SDG and diesel fire pump fuel oil storage tanks for microbiological organisms (NOC-AE-10002607) (NOC-AE-11002758). • Require analysis for water, biological activity, sediment, and particulate contamination of the diesel fire pump fuel oil storage tanks, lighting diesel generator fuel oil tank, and the BOP diesel generator fuel oil day tanks on a quarterly basis (NOC-AE-10002607) (NOC-AE-11002681) (NOC-AE-11002758).	Prior to the period of extended operation	B2.1.14	NOC-AE-10002607, October 25, 2010 NOC-AE-11002681, June 16, 2011 NOC-AE-11002758, November 30, 2011 NOC-AE-11002763, December 6, 2011

No.	Commitment	Implementation Schedule	LRA Section	Reference Letter & Date
	• Conduct ultrasonic testing or pulsed eddy current thickness examination to detect corrosion-related wall thinning once on the tank bottoms for the SDG and diesel fire pump and the BOP diesel generator fuel oil day tanks (NOC-AE-10002607). • Incorporate the sampling and testing of the diesel fire pump fuel oil storage tanks for particulate contamination and water and to incorporate the trending of water, particulate contamination, and microbiological activity in the SDG and diesel fire pump fuel oil storage tanks, lighting diesel generator fuel oil tank, and the BOP diesel generator fuel oil day tanks (NOC-AE-10002607) (NOC-AE-11002758).			
10	Enhance the Reactor Vessel Surveillance Program procedures by doing the following: (NOC-AE-10002607) • Include the withdrawal schedule and analysis of the ex-vessel dosimetry chain. • Demonstrate that the reactor vessel inlet and outlet nozzles are exposed to a fluence of less than 10^{17} n/cm^2, or incorporate the adjusted reference temperature (ART) for the inlet and outlet nozzles with bounding chemistry and fluence values into the pressure-temperature (P-T) limit curves. • Enhance the program to include the Unit 2 bottom head torus in the Reactor Vessel Surveillance Program.	Prior to the period of extended operation	B2.1.15	NOC-AE-10002607 October 25, 2010
11	Implement the One-Time Inspection Program, as described in LRA Section B2.1.16 (NOC-AE-10002607)	During the 10 years prior to the period of extended operation	B2.1.16	NOC-AE-10002607, October 25, 2010
12	Implement the Selective Leaching of Materials Program, as described in LRA Section B2.1.17 (NOC-AE-10002607) (NOC-AE-12002789)	During the 5 years prior to the period of extended operation	B2.1.17	NOC-AE-10002607, October 25, 2010 NOC-AE-12002789, January 26, 2012
13	Enhance the Buried Piping and Tanks Inspection Program specifications by doing the following: (NOC-AE-11002681) • Lower coated piping carefully into a trench to avoid external coating damage. • Use proper storage and handling practices to prevent damage to pipe coating prior to installation; practices include padded storage, use of proper slings for installation, and ultraviolet light resistant topcoats. • Over excavate trenches, use qualified backfill for bedding piping, and take care during backfilling to prevent rocks and debris from striking and damaging the pipe	Prior to the period of extended operation	B2.1.18	NOC-AE-11002681, June 16, 2011

No.	Commitment	Implementation Schedule	LRA Section	Reference Letter & Date
	coating. • Include the coating used for copper-alloy buried piping in the coating database; the coating system shall be in accordance with National Association of Corrosion Engineers (NACE) SP0169-2007and will be used for repair or for new coatings of the buried copper-alloy piping in the ECW system. • Coat the portion of the ECW system copper-alloy piping directly embedded in backfill or directly encased in concrete, extending the coating 2 feet or more above grade. Enhance the Buried Piping and Tanks Inspection Program procedures to include the following: (NOC-AE-11002681). • Consider backfill located within 6 inches of the pipe, and consistent with American Society for Testing and Materials (ASTM) D 448-08 size number 67, acceptable. Backfill quality is determined through examination during the inspections conducted by the program. Backfill that does not meet the ASTM criteria, during the initial and subsequent inspections of the program, is considered acceptable if the inspections of buried piping do not reveal evidence of mechanical damage to the pipe coatings due to the backfill. • Ensure the cathodic protection system survey is performed annually. • Monitor the output of the cathodic protection system rectifiers every 2 months. Record the measured current at each rectifier and compare it against a target value. Following the completion of the plant yard cathodic protection system annual survey, record the current of the rectifier used to achieve an acceptable pipe/soil potential. That current will be the target current for the rectifier until the next annual survey. If the current measured at the rectifier during the bimonthly monitoring deviates significantly from the target value, create a condition report. The rectifier current should be adjusted to an acceptable value. The results of the survey will be documented and trended to identify degrading conditions. When degraded rectifier performance is identified, documentation is required in accordance with the Corrective Action Program. The system should not be operated outside of established acceptable limits for longer than 90 days. • Recommend increased monitoring of the cathodic protection system or additional inspections, or both, if adverse indications are discovered during the monitoring of the cathodic protection system. • Evaluate the effectiveness of isolating fittings, continuity bonds, and casing isolation during the plant yard cathodic protection system annual survey. This may be accomplished through electrical measurements. • Visually inspect buried piping and, if significant indications of degradation are			

No.	Commitment	Implementation Schedule	LRA Section	Reference Letter & Date
	observed, supplement the visual inspections by surface or volumetric (or both) non-destructive testing. • Define the inspection interval for the program-directed inspections as every 10 years, beginning the 10-year interval prior to the beginning of the period of extended operation. • Select the buried and underground piping inspection locations based on risk, considering susceptibility to degradation and consequences of failure. • Consider the External Corrosion Direct Assessment, as described in NACE Standard Practice SP0502-2010, for use in identifying inspection locations. • Credit opportunistic examinations of non-leaking pipes toward required examinations only if they meet the risk ranking selection criteria. • Use guided wave ultrasonic or other advanced inspection techniques, if practical, for the purpose of determining piping locations that should be inspected. These inspections may not be used as substitutes for inspections required by the program. • Credit an inspection of piping shared between Units 1 and 2 toward the required inspections of only one unit. • Examine any piping, valves, and closure bolting exposed during inspections. • Examine bolting for loss of material and loose or missing fasteners. • Include two alternatives to directed inspections of the buried or underground piping that is safety-related, hazmat, or both. – The first alternative is to hydrostatically test 25 percent of the subject piping on an interval not to exceed 5 years. – The second alternative is an internal inspection of 25 percent of the subject piping by a method capable of accurately determining pipe wall thickness. • Flow testing of the fire mains, as described in National Fire Protection Act (NFPA) 25, to detect degradation of the buried pipe in lieu of visual inspections of the fire protection system buried and underground piping. • Define “hazmat pipe” as pipe that, during normal operation, contains fluids that, if released, would be detrimental to the environment. • Include examples of adverse indications discovered during piping inspections. • Repair or replace the affected component when adverse indications failing to meet			

No.	Commitment	Implementation Schedule	LRA Section	Reference Letter & Date
	the acceptance criteria described in the program are discovered. • Indicate that an analysis may be conducted to determine the potential extent of the degradation, when it is observed. • Double inspection sample sizes within the affected piping categories when adverse indications are detected during inspection of safety-related or hazmat buried pipe. If adverse indications are found in the expanded sample, double the inspection sample size again. Continue the doubling of the inspection sample size until no more adverse conditions are found. If adverse conditions are extensive, inspections may be halted in an area of concern that is planned for replacement, provided continued operation does not pose a significant hazard. Expansion of sample size may be limited to the piping subject to the observed degradation mechanism. • Define the scope of inspection for buried piping using the criteria in the GALL Report. Base the scope of inspection on the condition of cathodic protection, backfill, and coating of the piping. Ensure the scope of inspection increases when the cathodic protection system does not meet operability requirements or when backfill is examined and does not meet the backfill acceptance criteria. • Examine at least 10 feet of piping during each inspection of buried piping. If the entire length piping is less than 10 feet, inspect the entire length of piping. • Indicate that the inspections may be limited to 10 percent of the piping under consideration, per inspection interval, regardless of the inspection scope prescribed in the GALL Report guidance. • Perform one inspection of all buried stainless steel safety-related piping per inspection interval. • Examine at least 10 feet of piping during each inspection of underground piping. If the entire length of piping is less than 10 feet, inspect the entire length. • Inspect the underground stainless steel pipe in the auxiliary feedwater system once each inspection interval. • Observe for brittle failure at flanges, connections, and joints due to frost heaving, soil stresses, or groundwater effects during inspection of buried piping. • For coated piping, indicate that there should be no evidence of coating degradation. If coating degradation is present, it may be considered acceptable if it is determined to be insignificant by an individual possessing a NACE operator qualification, or otherwise meeting the qualifications to evaluate coatings as described in 49 CFR Parts 192 and 195.			

No.	Commitment	Implementation Schedule	LRA Section	Reference Letter & Date
	• Indicate that for any hydrostatic tests credited by the program, the condition "without leakage" may be met by demonstrating that the test pressure does not change significantly during the test.			
14	Implement the One-Time Inspection of American Society of Mechanical Engineers (ASME) Code Class 1 Small-Bore Piping Program, as described in LRA Section B2.1.19 (NOC-AE-10002607) (NOC-AE-11002681).	During the 6 years prior to the period of extended operation	B2.1.19	NOC-AE-10002607, October 25, 2010 NOC-AE-11002681, June 16, 2011
15	Implement the External Surfaces Monitoring Program, as described in LRA Section B2.1.20 (NOC-AE-10002607).	Prior to the period of extended operation	B2.1.20	NOC-AE-10002607, October 25, 2010
16	Enhance the Flux Thimble Tube Inspection Program by generating a new procedure that includes the following provisions: (NOC-AE-10002607) • Perform a wall thickness eddy current inspection of all flux thimble tubes that form part of the reactor coolant system pressure boundary. Schedule the inspections for each outage. An inspection may be deferred by using an evaluation that considers the actual wear rate. • Design engineering personnel will evaluate flux thimble tube wear. Perform corrective actions based on evaluation results after each inspection. • Design engineering personnel will trend wall thickness measurements and calculate wear rates after each inspection. • 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 a description of the testing and analysis methodology and percent through-wall acceptance criteria of a maximum of 80 percent through-wall loss. • Remove flux thimbles from service to ensure the integrity of the reactor coolant system pressure boundary for flux thimble tubes that cannot be inspected over the tube length, that are subject to wear due to restriction or other defect, and that cannot be shown by analysis to be satisfactory for continued service.	Prior to the period of extended operation	B2.1.21	NOC-AE-10002607,October 25, 2010
17	Implement the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, as described in LRA Section B2.1.22. (NOC-AE-10002607) (NOC-AE-11002764)	During the 5 year period prior to the period of extended operation	B2.1.22	NOC-AE-10002607,October 25, 2010 NOC-AE-11002764, December 15, 2011

No.	Commitment	Implementation Schedule	LRA Section	Reference Letter & Date
18	Enhance the Lubricating Oil Analysis Program procedures by doing the following: (NOC-AE-10002607) • Require analysis for particle count of the lubricating oil for the centrifugal charging pump. • 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.	Prior to the period of extended operation	B2.1.23	NOC-AE-10002607, October 25, 2010
19	Implement the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program as described in LRA Section B2.1.24. (NOC-AE-10002607)	Prior to the period of extended operation	B2.1.24	NOC-AE-10002607, October 25, 2010
20	Enhance the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program procedures by doing the following: • Identify the cables, manholes, and trenches that are within the scope of the program (NOC-AE-11002607) (NOC-AE-11002732). • Require all in-scope non-EQ inaccessible medium and low voltage power cables (>400 volts) exposed to significant moisture be tested at least once every 6 years, with the first test being completed prior to period of extended operation. (NOC-AE-10002607) (NOC-AE-11002681) (NOC-AE-11002732) (NOC-AE-12002789) • Require that the acceptance criteria be defined prior to each test for the specific type of test performed and the specific cable tested. (NOC-AE-10002607) • 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 engineering evaluation shall consider the significance of the 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. (NOC-AE-10002607) (NOC-AE-11002732) • Inspect in-scope manholes and trenches based on plant-specific operating experience with water accumulation. (NOC-AE-11002732) • Require inspections be conducted at least annually. (NOC-AE-11002732) • Include performance of event-driven inspections of in-scope manholes as an on-demand activity based on actual plant experience. (NOC-AE-11002769)	Prior to the period of extended operation	B2.1.25	NOC-AE-10002607, October 25, 2010 NOC-AE-11002681, June 16, 2011 NOC-AE-11002732,October 10, 2011 NOC-AE-11002769, Dec 7, 2011 NOC-AE-11002772, January 5, 2012 NOC-AE-12002789, January 26, 2012

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	• Perform direct observation that cables are not wetted or submerged. (NOC-AE-11002732) • Remove collected water and confirm sump pump operability. (NOC-AE-11002732) • Initiate a corrective action if wetted cables or inoperable sump pumps are found. (NOC-AE-11002732) • Inspect cables/splices and cable support structures if wetted cables are found. (NOC-AE-11002732) • Take corrective actions to keep cables dry (NOC-AE-11002732) • Evaluate manhole inspection results based on actual plant experience, with the inspection frequency increased based on experience with water accumulation. (NOC-AE-11002732) (NOC-AE-11002772) • Test in-scope inaccessible medium and low voltage (>400 volts) power cables exposed to significant moisture using a test capable of detecting reduced insulation resistance. (NOC-AE-11002732) • Trend inspection and test results to provide additional information on the rate of cable insulation degradation. (NOC-AE-11002732) • Test frequency may be adjusted based on test results or operating experience. (NOC-AE-11002772) • Require that the acceptance criterion for manhole and trench be cables/splices and support structures is that they are not submerged or immersed in water. (NOC-AE-11002732 • Require an extent of condition when an unacceptable condition or situation is identified. (NOC-AE-11002732)			
21	Enhance the Metal-Enclosed Bus Program procedures by doing the following: (NOC-AE-11002732) • Identify the metal enclosed buses (MEBs) that are within the scope of the program. • Inspect internal portions of all MEBs for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion every 10 years. • Inspect non-segregated phase bus insulation and isolated phase bus insulators for signs of embrittlement, cracking, melting, swelling, or discoloration every 10 years. • Inspect internal bus supports for structural integrity and signs of cracks every	Prior to the period of extended operation	B2.1.26	NOC-AE-11002732, October 10, 2011

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	10 years. • Inspect bus enclosure assemblies for loss of material due to corrosion and hardening of boots and gaskets every 10 years. • Inspect 20 percent of the population of non-segregated phase bus accessible bolted connections insulation material (with a maximum sample size of 25) for surface anomalies every 5 years. • Perform the first inspection of all portions of in-scope MEBs prior to the period of extended operation. • Identify acceptance criteria for non-segregated phase bus insulation and isolated phase bus insulators as no unacceptable visual indications of surface anomalies. • Identify acceptance criteria for non-segregated phase bus sections and internal portions of isolated phase bus as no unacceptable indications of corrosion, cracks, foreign debris, excessive dust buildup, loss of material, hardening, or evidence of water intrusion. • Identify acceptance criteria for the exterior of MEBs as no unacceptable indications of general corrosion. • Identify acceptance criteria for boots and gaskets as no unacceptable indications of cracking, checkering, or discoloration. • Identify acceptance criteria for accessible bolted connection insulation material as no unacceptable evidence of embrittlement, cracking, melting, discoloration, swelling, or surface contamination. • Require an engineering evaluation when acceptance criteria are not met, to include a determination of corrective actions. • Require an engineering evaluation to determine whether the unacceptable conditions may be applicable to other accessible or inaccessible MEBs.			
22	Enhance the ASME Code, Section XI, Subsection IWL Program procedures by doing the following: (NOC-AE-10002607) • Incorporate the 2004 Edition of ASME Code, Section XI, Subsection IWL (no addenda), supplemented with the applicable requirements of 10 CFR 50.55a(b)(2).	Prior to the period of extended operation	B2.1.28	NOC-AE-10002607, October 25, 2010
23	Enhance the ASME Code, Section XI, Subsection IWF Program procedures by doing the following: • Incorporate the 2004 Edition of ASME Code, Section XI, Subsection IWF (with no	Prior to the period of extended operation	B2.1.29	NOC-AE-10002607, October 25, 2010 NOC-AE-11002732,

No.	Commitment	Implementation Schedule	LRA Section	Reference Letter & Date
	addenda). (NOC-AE-10002607) • Specify the preventive actions for storage, protection, and lubricants recommended in Section 2 of Research Council for Structural Connections publication, “Specification for Structural Joints Using ASTM A325 or A490 Bolts,” for ASTM A325, ASTM F1852 or ASTM 490 bolts. (NOC-AE-11002732) • Specify that visual examinations are augmented with volumetric examinations, in accordance with ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1, to detect stress corrosion cracking (SCC) for 20 percent (25 bolts maximum per unit) of high strength bolts greater than 1-inch nominal diameter and with an actual yield strength greater than or equal to 150 ksi. (NOC-AE-11002772)			October 10, 2011 NOC-AE-11002772, January 5, 2012
24	Enhance the 10 CFR Part 50 Appendix J Program procedures by doing the following: (NOC-AE-10002607) • Specify a surveillance frequency of 10 years following a successful Type A test.	Prior to the period of extended operation	B2.1.30	NOC-AE-10002607, October 25, 2010
25	Enhance the Structures Monitoring Program procedures by doing the following: • Include the switchyard control building into the scope of the Structures Monitoring Program. (NOC-AE-11002759) • 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/enclosures and associated anchorage. (NOC-AE-10002607) • Monitor at least two groundwater samples every 5 years for pH, sulfates, and chloride concentrations. (NOC-AE-10002607) • Specify that the inspection frequency for structures within the scope of license renewal will be in accordance with American Concrete Institute (ACI) 349.3R, Table 6.1, as follows: (NOC-AE-11002732) – For below-grade structures and structures in controlled interior environment (except inside primary containment), all accessible areas of both units will be inspected every 10 years. – For all other structures (including inside primary containment), all accessible areas of both units will be inspected every 5 years. • Specify inspector qualifications in accordance with ACI 349.3R-96. (NOC-AE-10002607) • Perform periodic visual inspection of the accessible sections of the spent fuel pool	Prior to the period of extended operation	B2.1.32	NOC-AE-10002607, October 25, 2010 NOC-AE-11002732, October 10, 2011 NOC-AE-11002737, October 18, 2011 NOC-AE-11002759, November 21, 2011 NOC-AE-11002772, January 5, 2012 NOC-AE-12002789, January 26, 2012

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	and transfer canal tell-tale drain lines for blockage every 5 years. The first inspection will be performed within the 5 years before entering the period of extended operation. (NOC-AE-11002732) (NOC-AE-11002772) (NOC-AE-12002789) • Specify ACI 349.3R-96 and ACI 201.1R-68 as the basis for defining quantitative acceptance criteria. (NOC-AE-11002732) • Specify the preventive actions for storage, protection, and lubricants recommended in Section 2 of Research Council for Structural Connections publication “Specification for Structural Joints Using ASTM A325 or A490 Bolts” for ASTM A325, ASTM F1852, or ASTM 490 bolts. (NOC-AE-1102732) • Enhance procedures to perform opportunistic inspections of exposed portions of the below-grade concrete when excavated for any reason. (NOC-AE-11002737) • Enhance procedures to require an evaluation in cases where groundwater is determined to be aggressive or inspections of accessible concrete structural elements identify degradation. The evaluation will include determination of the appropriate actions necessary to assure that the affected structures will continue to perform their intended functions. These actions may include increased visual inspections or other examination techniques. (NOC-AE-11002737) • Specify that visual examinations will be augmented with volumetric examinations, in accordance with ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1, to detect SCC for 20 percent (25 bolts maximum) of high-strength bolts greater than 1-inch nominal diameter and with an actual yield strength greater than or equal to 150 ksi. (NOC-AE-11002772)			
26	Enhance Regulatory Guide (RG) 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program procedures by doing the following: • Specify inspections at intervals not to exceed 5 years or to immediately follow significant natural phenomena except sediment monitoring, which is performed every 10 years. (NOC-AE-10002607) (NOC-AE-11002758) • Specify the preventive actions for storage, protection, and lubricants recommended in Section 2 of Research Council for Structural Connections publication, “Specification for Structural Joints Using ASTM A325 or A490 Bolts” for ASTM A325, ASTM F1852, or ASTM 490 bolts. (NOC-AE-11002732) • Specify ACI 349.3R-96 and ACI 201.1R-68 as the basis for defining quantitative acceptance criteria. (NOC-AE-11002732)	Prior to the period of extended operation	B2.1.33	NOC-AE-10002607, October 25, 2010 NOC-AE-1002732, October 10, 2011 NOC-AE-11002758, November 30, 2011
27	Implement the PWR Reactor Internals Program as described in LRA Section B2.1.35.	Within 24 months after the issuance of	B2.1.35	NOC-AE-10002607,

No.	Commitment	Implementation Schedule	LRA Section	Reference Letter & Date
	(NOC-AE-10002607) (NOC-AE-12002797)	EPRI 1022863, "PWR Internals Inspection and Evaluation Guideline MRP-227-A"		October 25, 2010 NOC-AE-12002797, February 27, 2012
28	Implement the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program as described in LRA Section B2.1.36. (NOC-AE-10002607)	Prior to the period of extended operation	B2.1.36	NOC-AE-10002607, October 25, 2010
29	As additional industry and plant-specific aging-related operating experience becomes available, evaluate and incorporate it into applicable AMPs or develop new AMPs, as necessary, to provide assurance that the effects of aging will be managed during the period of extended operation. (NOC-AE-11002683)	Within 10 years prior to entering the period of extended operation	B2.1.16 B2.1.17 B2.1.19 B2.1.20 B2.1.22 B2.1.24 B2.1.35 B2.1.36 B1.4	NOC-AE-11002683, June 23, 2011
30	Enhance the Metal Fatigue of Reactor Coolant Pressure Boundary Program procedures by doing the following: • Include additional locations necessary to ensure accurate calculations of fatigue. (NOC-AE-10002607) • Include additional transients that contribute significantly to fatigue usage. (NOC-AE-10002607) • Include counting of the transients used in the fatigue crack growth analyses, which support the leak-before-break analyses and ASME Code, Section XI evaluations, to ensure the analyses remain valid. (NOC-AE-11002672) • 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. (NOC-AE-10002607) • 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. (NOC-AE-10002607) • Include appropriate corrective actions to be invoked if a component approaches a	Prior to the period of extended operation	B3.1	NOC-AE-10002607, October 25, 2010 NOC-AE-11002672, May 12, 2011 NOC-AE-11002759, November 21, 2011

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	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. (NOC-AE-10002607) (NOC-AE-11002672) (NOC-AE-11002759)			
31	STPNOC commits to the following: (NOC-AE-10002607) • for reactor coolant system nickel-alloy pressure boundary components: – Implement applicable NRC orders, bulletins, and generic letters associated with nickel-alloys. – Implement staff-accepted industry guidelines. – Participate in the industry initiatives, such as owners group programs and the EPRI Materials Reliability Program, for managing aging effects associated with nickel-alloys. – Submit an inspection plan for reactor coolant system nickel-alloy pressure boundary components to the NRC for review and approval upon completion of these programs, but not less than 24 months before entering the period of extended operation. • for reactor vessel internals: – 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. – Submit an inspection plan for reactor internals to the NRC for review and approval upon completion of these programs, but not less than 24 months before entering the period of extended operation.	Concurrent with industry initiatives and upon completion submit an inspection plan and not less than 24 months before entering the period of extended operation	3.1	NOC-AE-10002607, October 25, 2010
32	Replace the seven diesel generator cooling water expansion joints that are projected to exceed the analyzed number of cycles during the period of extended operation. The analyses for the replacement expansion joints will include the period of extended operation. (NOC-AE-10002607)	Prior to the period of extended operation	4.3.6	NOC-AE-10002607, October 25, 2010
33	Periodic inspection of a sample of transmission conductor connections for loose connections using thermography is currently performed as part of the preventive maintenance activities. The periodic thermography will continue into the period of extended operation. (NOC-AE-10002607)	Continued into the period of extended operation	3.6.2.2.3	NOC-AE-10002607, October 25, 2010

No.	Commitment	Implementation Schedule	LRA Section	Reference Letter & Date
34	Prior to the period of extended operation, STP 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. If more limiting components are identified, the most limiting component will be evaluated for the effects of the reactor coolant environment on fatigue usage. If the limiting location consists of nickel alloy, the methodology for nickel alloy in NUREG/CR-6909 will be used to perform the environmentally-assisted fatigue calculation. The additional evaluation will be performed through the Metal Fatigue of Reactor Coolant Pressure Boundary Program in accordance with 10 CFR 54.21(c)(1)(iii). (NOC-AE-11002731)	Prior to the period of extended operation	B3.1	NOC-AE-11002731, September 15, 2011
35	Enhance the ASME Code, Section XI, Subsection IWE Program procedures by doing the following: (NOC-AE-11002732) • Specify the preventive actions for storage, protection, and lubricants recommended in Section 2 of Research Council for Structural Connections publication, “Specification for Structural Joints Using ASTM A325 or A490 Bolts,” for ASTM A325, ASTM F1852, or ASTM 490 bolts.	Prior to the period of extended operation	B2.1.27	NOC-AE-11002732, October 10, 2011
36	Enhance the Masonry Wall Program procedures by specifying that the inspection frequency for structures within the scope of license renewal will be in accordance with ACI 349.3R, Table 6.1, as follows: (NOC-AE-11002732) • For below-grade structures and structures in controlled interior environment (except inside primary containment), inspect all accessible areas of both units every 10 years. • For all other structures (including inside primary containment), inspect all accessible areas of both units every 5 years.	Prior to the period of extended operation	B2.1.31	NOC-AE-11002732, October 10, 2011
37	Take groundwater samples at multiple locations around the site every 3 months for at least 24 consecutive months. The samples will analyze for pH, sulfates, and chlorides. This sampling plan will begin no later than September 2012. (NOC-AE-11002737)	September 2012	B2.1.32	NOC-AE-11002737, October 18, 2011
38	Enhance the Reactor Head Closure Studs Program procedures by doing the following: • Preclude the future use of replacement closure stud assemblies fabricated from material with an actual measured yield strength greater than or equal to 150 ksi. The use of currently installed components and any spare components that are currently on site is allowed. (NOC-AE-11002750)	Prior to the period of extended operation	B2.1.3	NOC-AE-11002750, November 4, 2011 NOC-AE-11002764, December 15, 2011 NOC-AE-12002830, April 17, 2012
39	Enhance the Selective Leaching of Aluminum Bronze Program procedures by doing the	Prior to the period of	B2.1.37	NOC-AE-11002766,

No.	Commitment	Implementation Schedule	LRA Section	Reference Letter & Date
	following: (NOC-AE-11002766) • Examine aluminum bronze materials exposed during inspection of the buried ECW piping for evidence of selective leaching. • Perform periodic metallurgical testing of aluminum bronze material components to update the structural integrity analyses, confirm load carrying capacity, and determine degree of dealloying by testing above ground ECW system components removed from service as follows: (NOC-AE-12002853) – For each 10-year interval beginning 10 years prior to the period of extended operation, 20 percent of leaking components removed from service, but at least one, will be tested every 5 years. – Tensile test samples from a removed component will be tested to include both leaking and non-leaking portions of the component. – If at least two leaking components are not identified 2 years prior to the end of each 10-year testing interval, a risk-rank approach based on those components most susceptible to degradation will be used to identify candidate components for removal and testing so at least two components are tested during the 10-vear interval. – The samples will be tested for chemical composition including aluminum content, mechanical properties (such as yield and ultimate tensile strengths) and microstructure. – Trend ultimate tensile strength and compare to the acceptance criterion. – Determine degree of dealloying and presence of cracks by destructive examination. Trend the degree of dealloying and cracking by comparing examination results with previous examination results. – Perform an engineering evaluation at the end of each test to determine if the sample size requires adjustment based on the results of the tests. – The acceptance criterion for ultimate tensile strength value of aluminum bronze material is greater than or equal to 30 ksi. The acceptance criterion for y ield strength is equal to or greater than one-half of the ultimate strength. – A corrective action document will be initiated when the acceptance criterion is not met. • If a leak from below-grade welds is discovered by surface water monitoring or during a buried ECW piping inspection, remove a section of each leaking weld for destructive metallurgical examination.	extended operation		December 8, 2011 NOC-AE-12002853, May 31, 2012 NOC-AE-12002889, October 4, 2012

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40	Enhance the Protective Coating Monitoring and Maintenance Program procedures by doing the following: (NOC-AE-12002797) • Specify parameters monitored or inspected include any visible defects, such as blistering, cracking, flaking, peeling, rusting, and physical damage, as specified in ASTM D 5163-08. • Specify that inspection frequencies, personnel qualifications, inspection plans, inspection methods, and inspection equipment meet the requirements of ASTM D 5163-08. • Perform a pre-inspection review of the previous two monitoring reports and, based on inspection report results, prioritize repair areas as either needing repair during the same outage, needing repair during the next available outage, or needing re-evaluation in the next available outage. • Develop a standardized coating condition assessment report form that will include both the identification of coatings found intact with no defects identified, and the identification of coatings that were not inspected along with the reason why the inspection could not be conducted. • Develop a standardized coating condition assessment report that will include written or photographic documentation, or both, of coating inspection areas, failures, and defects. • Perform destructive/non-destructive tests by individuals trained in the applicable referenced standards of Guide D5498 on an as-needed basis as determined by the Nuclear Coatings Specialist.	Prior to the period of extended operation	B2.1.39	NOC-AE-12002797, February 27, 2012
41	Enhance the STP Operating Experience Program (OEP) and Corrective Action Program for managing the effects of aging by doing the following: (NOC-AE-12002797) • Add license renewal interim staff guidance and revisions to the GALL Report to the OEP procedure as sources of information within the scope of this program. • Revise the OEP procedure to include “aging effects” to the list of characteristics for determining applicability of an operating experience document that may require further evaluation. A screened-in evaluation should consider: (a) systems, structures, or components, (b) materials, (c) environments, (d) aging effects, (e) aging mechanisms, and (f) AMPs. • Review the Corrective Action Program event codes to determine if additional codes are needed to ensure age-related degradation effects are identified. • Perform a training “needs analysis” for those plant personnel, including AMP owners,	No later than the date the renewed operating licenses are issued	A1	NOC-AE-12002797, February 27, 2012 NOC-AE-12002870, June 14, 2012 NOC-AE-12002907, December 6, 2012

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	who screen, assign, evaluate, implement, and submit plant-specific and industry operating experience information for age-related effects. Include in the analysis: o A requirement that individuals complete training before performing tasks, and o A determination of the periodicity of the training • Revise the OEP procedure to provide criteria for reporting plant-specific operating experience of age-related degradation.			
42	Enhance the Reactor Head Closure Studs Program procedures by doing the following: • Perform a remote VT-1 of stud insert #30 concurrent with the volumetric examination once every 10 years to confirm no additional loss of bearing surface area.	Starting with the current (Third Interval) 10-year ASME Code Section XI inspection interval	B2.1.3	NOC-AE-12002830, April 17, 2012
43	The seal cap enclosures from Unit 2 safety injection system check valve SI0010A and from Unit 1 and Unit 2 chemical volume control system check valves CV0001, CV0002, CV0004, and CV0005 will be permanently removed. After removal of the seal cap enclosures, the component bolting will be replaced or inspected for intergranular SCC.	2012 Refueling Outage (Unit 1) 2013 Refueling Outage (Unit 2)	B2.1.7	NOC-AE-12002855, May 14, 2012
44	Structural integrity analyses will be updated and testing will be conducted to confirm that methodologies and assumptions based on past information remain valid. • Six samples from three aluminum bronze components recently removed from service will be tested. • The samples will be tested for chemical composition including aluminum content, mechanical properties {such as fracture toughness, yield and ultimate tensile strengths} and microstructure. • The acceptance criterion for ultimate tensile strength value of aluminum bronze material is greater than or equal to 30 ksi. The acceptance criterion for fracture toughness is 65 ksi in $^{1/2}$ for aluminum bronze castings and at welded joints in the heat affected zones. The acceptance criterion for yield strength is equal to or greater than one-half of the ultimate strength. • Trend ultimate tensile strength and compare to the acceptance criterion. • Determine degree of dealloying and presence of cracks by destructive examination. Trend the degree of dealloying and cracking by comparing examination results with previous examination results. • The structural integrity analyses will be updated, as required.	Prior to January 2013	B2.1.37	NOC-AE-12002853, May 31, 2012 NOC-AE-12002889, October 4, 2012

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	• The results of the testing and any required changes to the structural integrity analyses will be completed and sent to the NRC staff for review.			

45	Enhance the Selective Leaching of Aluminum Bronze procedures to:
	• Volumetrically examine aluminum bronze material components in the ECW system that demonstrate external leakage where the configuration supports this type of examination.
	• Destructively examine each aluminum bronze material component in the ECW system that demonstrates external leakage for the presence or absence of internal cracks and for the degree of dealloying. Profiling will continue until 10 percent of susceptible components are examined to validate the input parameters to the structural integrity analyses.
	  o Trend the degree of dealloying and cracking by comparing examination results with previous examination results.
	• Metallurgically test aluminum bronze material components in the ECW system that demonstrate external leakage until the following population of components is tested:
	  o At least three different size components of two samples each are tested, and
	  o At least nine total samples are tested.
	  o Perform fracture toughness testing of test samples that include a crack in the dealloyed material where sufficient sample size supports bend testing.
	  o Trend ultimate tensile strength and compare to the acceptance criterion.
	  o Test samples for chemical composition including aluminum content, mechanical properties (such as yield and ultimate tensile strengths) and microstructure.
	  o Determine the degree of dealloying by destructive examination.
	  o Trend the degree of dealloying and cracking by comparing examination results with previous examination results.
	• The acceptance criterion for ultimate tensile strength value of aluminum bronze material is greater than or equal to 30 ksi. The acceptance criterion for fracture toughness is 65 ksi in $^{1/2}$ for aluminum bronze castings and at welded joints in the heat affected zones. The acceptance criterion for yield strength is equal to or greater than one-half of the ultimate strength.
	• Perform an engineering evaluation at the end of each test to determine if the sample
		March 31, 2013	B2.1.37	NOC-AE-12002889, October 4, 2012

No.	Commitment	Implementation Schedule	LRA Section	Reference Letter & Date
	size requires adjustment based on the results of the tests. • Update the structural integrity analyses as required to validate adequate load carrying capacity.			
46	Leak rates that could occur upstream of any individual component supplied by the ECW system will be determined to validate the maximum size flaw for which piping can still perform its intended function. • A summary of the results of these leak rates will be provided to the NRC for review.	March 31, 2013	B2.1.37	NOC-AE-12002889, October 4, 2012

APPENDIX B

CHRONOLOGY

This appendix contains a chronological listing of the routine correspondence between the staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff) and the South Texas Project Nuclear Operating Company (STPNOC) (the applicant) and other correspondence regarding the staff's review of the South Texas Project (STP), Units 1 and 2, license renewal application (LRA), Docket Numbers 50-498 and 50-499.

Document Date	Title
10/25/2010	Letter from Powell, G.T., STPNOC, "South Texas Project, Units 1 and 2, Transmittal of License Renewal Application" (Agencywide Document Access and Management System (ADAMS) Accession No. ML103010257)
10/25/2010	STPNOC, "South Texas Project, Units 1 and 2, License Renewal Application" (ADAMS Accession No. ML103010262)
10/28/2010	Letter from Harrison, A.W., STPNOC, "South Texas Project, Units 1 and 2, License Renewal Application Scoping Drawings" (ADAMS Accession No. ML103270165)
11/4/2010	Press Release: "Press Release-10-202: NRC Announces Availability of License Renewal Application for South Texas Project Nuclear Power Plant" (ADAMS Accession No. ML103081029)
11/23/2010	Letter to Powell, G.T., STPNOC, "Receipt and Availability of the License Renewal Application for the South Texas Project Electric Generating Station Units One and Two (LTR)" (ADAMS Accession No. ML103020399)
11/23/2010	*Federal Register* Notice: "FRN: General Notice. Notice of Receipt and Availability of Application for Renewal of South Texas Project, Units 1 and 2" (ADAMS Accession No. ML103020406)
11/23/2010	Letter to Moore, A., Bay City, TX, Public Library, "Maintenance of Reference Materials at the Bay City Public Library Related to the Review of South Texas Project, Units 1 and 2, License Renewal Application" (ADAMS Accession No. ML103090389)
11/23/2010	*Federal Register* Notice: "FRN: General Notice. USNRC STP Nuclear Operating Co. Notice of Receipt and Availability of Application for Renewal of South Texas Project Units 1 and 2" (ADAMS Accession No. ML103360179)
12/9/2010	Letter to Powell, G.T., STPNOC, "Project Manager Change for the License Renewal of South Texas Project, Units 1 and 2 (TAC No. ME4936)" (ADAMS Accession No. ML103410524)
12/9/2010	Letter from Powell, G.T., STPNOC, "South Texas Project, Units 1 and 2, Response to Request for Additional Information for the South Texas Project License Renewal Application" (ADAMS Accession No. ML103540235)
12/21/2010	Letter from Powell, G.T., STPNOC, "South Texas Project, Units 1 and 2, Response to Request for Additional Information Related to Part 1, Administrative Information, License Renewal Application" (ADAMS Accession No. ML103570142)
1/7/2011	Letter to Powell, G.T., STPNOC, "Determination of Acceptability & Sufficiency for Docketing, Proposed Review Schedule, and Opportunity for a Hearing Regarding the Application from STP Nuclear Operating Company for Renewal of the Operating Licenses for South Texas Project Electric Gene" (ADAMS Accession No. ML103420531)

Document Date	Title
1/7/2011	*Federal Register* Notice: "Notice of Acceptance for Docketing of the Application and Notice of Opportunity for Hearing Regarding Renewal of Facility Operating License Numbers NPF-76 and NPF-80 for an Additional 20-year Period STP Nuclear Operating Company, South Texas Project" (ADAMS Accession No. ML103420650)
2/17/2011	Letter from Harrison, A.W., STPNOC, "South Texas Project, Units 1 and 2, License Renewal Application Online Reference Portal" (ADAMS Accession No. ML110610201)
3/17/2011	Letter to Powell, G.T., STPNOC, "South Texas Project, Units 1 and 2, License Renewal Application Online Reference Portal" (ADAMS Accession No. ML110620203)
4/5/2011	Letter to Powell, G.T., STPNOC, "Project Manager Change for the License Renewal of South Texas Project, Units 1 and 2 (TAC No. ME4938)" (ADAMS Accession No. ML110872079)
4/14/2011	Letter to Powell, G.T., STPNOC, "Request for Additional Information for the Review of the South Texas Project, License Renewal Application—Section 2.4, 'Structural' (TAC Nos. ME4936, ME4937)" (ADAMS Accession No. ML110820579)
4/14/2011	Letter to Powell, G.T., STPNOC, "Request for Additional Information for the Review of the South Texas Project, License Renewal Application—Electrical Branch Scoping" (ADAMS Accession No. ML110890764)
4/22/2011	Meeting Summary, Daily J.W., "03/29/11 & 03/31/11 Summary of Telephone Conference Calls Held Between NRC and STP Nuclear Operating Company, Concerning Requests for Additional Information Pertaining to the South Texas Project, Units 1 and 2, License Renewal Application" (ADAMS Accession No. ML110940477)
5/5/2011	Letter from Powell, G.T., STPNOC, "South Texas Project, Units 1 and 2, Response to Request for Additional Information for License Renewal Application" (ADAMS Accession No. ML11130A026)
5/5/2011	Letter from Powell, G.T., STPNOC, "South Texas Project, Units 1 and 2, Response to Request for Additional Information for License Renewal Application" (ADAMS Accession No. ML11130A061)
5/12/2011	Letter from Powell, G.T., STPNOC, "South Texas Project, Units 1 and 2, Response to Request for Additional Information for License Renewal Application" (ADAMS Accession No. ML11145A090)
5/24/2011	Letter to Powell, G.T., STPNOC, "Request for Additional Information for the Review of the South Texas Project, Units 1 and 2, License Renewal Application Future Consideration of Operating Experience" (ADAMS Accession No. ML11137A092)
6/6/2011	Letter to Powell, G.T., STPNOC, "Plan for the Aging Management Program Regulatory Audit Regarding the South Texas Project, Units 1 and 2, License Renewal Application Review (TAC Nos. ME4936 and ME4937)" (ADAMS Accession No. ML11140A163)
6/16/2011	Letter from Powell, G.T., STPNOC, "South Texas Project, Units 1 and 2, Amendment 2 to the License Renewal Application" (ADAMS Accession No. ML11172A096)
6/23/2011	Letter from Powell, G.T., STPNOC, "South Texas Project, Units 1 and 2, Response to Request for Additional Information for License Renewal Application (TAC Nos. ME4936 and ME4937)" (ADAMS Accession No. ML11181A037)
7/5/2011	Letter from Powell, G.T., STPNOC, "South Texas Project, Units 1 and 2, Response to Request for Additional Information for the South Texas Project License Renewal Application" (ADAMS Accession No. ML11193A016)
7/5/2011	Letter from Powell, G.T., STPNOC, "South Texas Project, Units 1 and 2, Response to Request for Additional Information for the Review of the License Renewal Application"

Document Date	Title
	(ADAMS Accession No. ML11193A074)
7/6/2011	Meeting Summary, Daily, J.W., STPNOC, "Summary of Telephone Conference Call Held on May 23, 2011, Between the NRC and STPNOC, Concerning Requests for Additional Information Pertaining to the South Texas Project, LRA—Future Consideration of Operating Experience (TAC Nos. ME4936 and ME4937)" (ADAMS Accession No. ML11154A013)
7/12/2011	Letter to Powell, G.T., STPNOC, "Letter re: Request for Additional Information for South Texas Project Electric Generating Station, Units 1 and 2 License Renewal Application—Scoping and Screening Balance of Plant (TAC Nos. ME4936 and ME4937)" (ADAMS Accession No. ML11166A239)
7/28/2011	Letter to Powell, G.T., STPNOC, "Requests for Additional Information for the Review of the South Texas Project, License Renewal Application—Scoping and Screening Audit (TAC Nos. ME4936 and ME4937)" (ADAMS Accession No. ML11201A055)
8/9/2011	Letter from Powell, G.T., STPNOC, "South Texas Project, Units 1 and 2, Response to Request for Additional Information for the South Texas Project License Renewal Application (TAC Nos. ME4936 and ME4937)" (ADAMS Accession No. ML11234A045)
8/9/2011	Letter from Powell, G.T., STPNOC, "South Texas Project, Units 1 and 2, Response to Request for Additional Information for the Review of the South Texas Project License Renewal Application" (ADAMS Accession No. ML11245A101)
8/15/2011	Letter to Powell, G.T., STPNOC, "Requests for Additional Information for the Review of the South Texas Project, Units 1 and 2 License Renewal Application—Aging Management Programs Audit, Structures/Electrical (TAC Nos. ME4936 and ME4937)" (ADAMS Accession No. ML11214A005)
8/15/2011	Letter to Powell, G.T., STPNOC, "Requests for Additional Information for the Review of the South Texas Project, Units 1 and 2 License Renewal Application—Aging Management Programs Audit, Reactor Systems (TAC Nos. ME4936 and ME4937)" (ADAMS Accession No. ML11214A027)
8/15/2011	Letter to Powell, G.T., STPNOC, "Request for Additional Information for the Review of the South Texas Project, Units 1 and 2 License Renewal Application—Aging Management Programs Audit, Plant Systems (TAC Nos. ME4936 and ME4937)" (ADAMS Accession No. ML11214A088)
8/16/2011	Meeting Summary, Daily, J.W., STPNOC, "Summary of Telephone Conference Call Held on August 8, 2011, Between the U.S. Nuclear Regulatory Commission and STP Nuclear Operating Company, Concerning Requests for Additional Information Pertaining to the South Texas Project, License Renewal Application" (ADAMS Accession No. ML11222A001)
8/16/2011	Memo to File, Daily, J.W., "Summary of Telephone Conference Call Held on August 9, 2011, Between the U.S. NRC and STP Nuclear Operating Company, Concerning Requests for Additional Information Pertaining to the South Texas Project, License Renewal Application" (ADAMS Accession No. ML11222A002)
8/18/2011	Email to Aldridge, A.J., Taplett, K., STPNOC, "South Texas Project, Units 1 and 2, License Renewal—Errata in AMP RAI Package" (ADAMS Accession No. ML112300016)
8/18/2011	Letter from Powell, G.T., STPNOC, "South Texas Project, Units 1 and 2, Response to Request for Additional Information for the South Texas Project License Renewal Application (TAC Nos. ME4936 and ME4937)" (ADAMS Accession No. ML11238A071)
8/23/2011	Letter from Powell, G.T., STPNOC, "South Texas Project, Units 1 and 2, Response to Request for Additional Information for the South Texas Project License Renewal Application (TAC Nos. ME4936 and ME4937)" (ADAMS Accession No. ML11238A072)

Document Date	Title
8/23/2011	Letter from Powell, G.T., STPNOC, “South Texas Project, Units 1 and 2, Response to Request for Additional Information for License Renewal Application” (ADAMS Accession No. ML11250A067)
8/31/2011	Letter from Harrison, A.W., STPNOC, “South Texas Project, Units 1 and 2, Transmittal of Documents to Support Review of the South Texas Project License Renewal Application” (ADAMS Accession No. ML11256A056)
8/31/2011	Letter from Harrison, A.W., STPNOC, “Documents to Support Review of the South Texas Project License Renewal Application, List of Transmitted Documents Including Copy of Each Document, Enclosure to NOC-AE-11002720” (ADAMS Accession No. ML11256A057)
9/6/2011	Letter to Powell, G.T., STPNOC, “Scoping and Screening Audit Report Regarding the South Texas Project, Units 1 and 2 (TAC Nos. ME4936 and ME4937)” (ADAMS Accession No. ML11230A003)
9/6/2011	Letter from Powell, G.T., STPNOC, “South Texas Project, Units 1 and 2, Response to Request for Additional Information for the License Renewal Application” (ADAMS Accession No. ML11255A211)
9/12/2011	Letter from Powell, G.T., STPNOC, “South Texas Project, Units 1 and 2, Response to Requests for Additional Information for the License Renewal Application” (ADAMS Accession No. ML11259A014)
9/12/2011	Letter from Powell, G.T., STPNOC, “South Texas Project, Units 1 and 2, Transmittal of Document to Support Review of the License Renewal Application” (ADAMS Accession No. ML11259A031)
9/15/2011	Letter from Powell, G.T., STPNOC, “South Texas Project, Units 1 and 2, Response to Request for Additional Information for License Renewal Application (TAC Nos. ME4936 and ME4937)” (ADAMS Accession No. ML11266A019)
9/15/2011	Letter from Powell, G.T., STPNOC, “South Texas Project, Units 1 and 2, Response to Requests for Additional Information for License Renewal Application (TAC Nos. ME4936 and ME4937)” (ADAMS Accession No. ML11266A020)
9/21/2011	Letter to Powell, G.T., STPNOC, “Request for Additional Information for the Review of the South Texas Project, Units 1 and 2 License Renewal Application—Aging Management Review, Set 2 (TAC Nos. ME4936 and ME4937)” (ADAMS Accession No. ML112440201)
9/22/2011	Letter to Powell, G.T., STPNOC, “Aging Management Programs Audit Report Regarding the South Texas Project, Units 1 and 2, Station License Renewal Application (TAC Nos. ME4936 and ME4937)” (ADAMS Accession No. ML11224A265)
9/22/2011	Letter to Powell, G.T., STPNOC, “Requests for Additional Information for the Review of the South Texas Project, Units 1 and 2, License Renewal Application—Aging Management Review, Set 1 (TAC Nos. ME4936 and ME4937)” (ADAMS Accession No. ML11250A043)
9/22/2011	Letter to Powell, G.T., STPNOC, “Request for Additional Information for the Review of the South Texas Project, Units 1 and 2, License Renewal Application—Aging Management Review, Set 3 (TAC Nos. ME4936 and ME4937)” (ADAMS Accession No. ML11258A161)
10/4/2011	Meeting Summary, Daily, J.W., “Summary of Telephone Conference Call Held on September 28, 2011, Between the NRC and STP Nuclear Operating Company, Concerning Request for Additional Information Pertaining to the South Texas Project, LRA (TAC Nos. ME4936 and ME4937)” (ADAMS Accession No. ML11272A165)
10/10/2011	Letter from Powell, G.T., STPNOC, “South Texas Project, Units 1 and 2, Response to Requests for Additional Information for the License Renewal Application” (ADAMS Accession No. ML11291A152)

Document Date	Title
10/11/2011	Letter to Powell, G.T., STPNOC, "Requests for Additional Information for the Review of the South Texas Project, Units 1 and 2, License Renewal Application—Aging Management Review, Set 4 (TAC Nos. ME4936 and ME4937)" (ADAMS Accession No. ML11273A008)
10/11/2011	Letter to Powell, G.T., STPNOC, "Requests for Additional Information for the Review of the South Texas Project, Units 1 and 2, License Renewal Application—Aging Management Review, Set 5 (TAC Nos. ME4936 and ME4937)" (ADAMS Accession No. ML11273A017)
10/14/2011	Meeting Summary, Daily, J.W., "Summary of Telephone Conference Call Held on October 11, 2011, Between the USNRC and STP Nuclear Operating Company, Concerning Request for Additional Information Pertaining to the South Texas Project, License Renewal Application" (ADAMS Accession No. ML11286A002)
10/18/2011	Letter to Powell, G.T., STPNOC, "Requests for Additional Information for the Review of the South Texas Project, Units 1 and 2, License Renewal Application—Aging Management Program, Set 6" (ADAMS Accession No. ML11277A047)
10/18/2011	Meeting Summary, Daily, J.W., "Summary of Teleconference Call Held on October 6, 2011, Between the USNRC and STP Nuclear Operating Company, Concerning Request for Additional Information Pertaining to the STP, License Renewal Application" (ADAMS Accession No. ML11286A001)
10/18/2011	Letter from Powell, G.T., STPNOC, "South Texas Project, Units 1 and 2, Supplement to License Renewal Application (TAC Nos. ME4936 and ME4937)" (ADAMS Accession No. ML11298A082)
10/18/2011	Letter from Powell, G.T., STPNOC, "South Texas Project, Units 1 and 2, Response to Requests for Additional Information for License Renewal Application (TAC Nos. ME4938 and ME5122)" (ADAMS Accession No. ML11298A085)
10/25/2011	Meeting Summary, Daily, J.W., "Summary of Teleconference Call Held on September 7, 2011, Between the USNRC and STP Nuclear Operating Co., Concerning Requests for Additional Information Pertaining to the South Texas Project, License Renewal Application" (ADAMS Accession No. ML11250A129)
10/25/2011	Letter from Rencurrel, D.W., STPNOC, "South Texas Project, Units 1 and 2, Response to Requests for Additional Information for License Renewal Application (TAC Nos. ME4936 and ME4937)" (ADAMS Accession No. ML11305A076)
10/26/2011	Letter from Harrison, A.W., STPNOC, "South Texas Project, Units 1 and 2, Contact Information Change, License Renewal Application (TAC Nos. ME4936 and ME4937)" (ADAMS Accession No. ML11305A075)
11/3/2011	Letter to Rencurrel, D.W., STPNOC, "Requests for Additional Information for the Review of the South Texas Project, Units 1 and 2, License Renewal Application—Aging Management Program, Set 7" (ADAMS Accession No. ML11299A105)
11/3/2011	Letter from Harrison, A.W., STPNOC, "South Texas Project, Units 1 and 2, License Renewal Application Revised Scoping Drawings" (ADAMS Accession No. ML11318A121)
11/4/2011	Letter from Rencurrel, D.W., STPNOC, "South Texas Project, Units 1 and 2, Supplement to the License Renewal Application" (ADAMS Accession No. ML11319A026)
11/4/2011	Letter from Rencurrel, D.W., STPNOC, "South Texas Project, Units 1 and 2, Response to Requests for Additional Information for the Renewal Application" (ADAMS Accession No. ML11325A192)
11/9/2011	Meeting Summary, Daily, J.W., "Summary of Teleconference Call Held on October 31, 2011, Between USNRC and STP Nuclear Operating Company, Concerning Requests for Additional Information Pertaining to the South Texas Project, License Renewal Application, Set 7" (ADAMS Accession No. ML11307A202)

Document Date	Title
11/15/2011	Letter to Rencurrel, D.W., STPNOC, “Requests for Additional Information for the Review of South Texas Project, Units 1 and 2, License Renewal Application—Aging Management Program, Set 8” (ADAMS Accession No. ML11306A155)
11/17/2011	Letter from Rencurrel, D.W., STPNOC, “South Texas Project Units 1 and 2, Response to Requests for Additional Information for the License Renewal Application, Set 6 (TAC Nos. ME4936 and ME4937)” (ADAMS Accession No. ML11333A093)
11/21/2011	Letter from Rencurrel, D.W., STPNOC, “South Texas Project Units 1 and 2, Response to Requests for Additional Information for the South Texas Project License Renewal Application—Aging Management Review, Set 2 (TAC Nos. ME4936 and ME4937)” (ADAMS Accession No. ML11333A095)
11/21/2011	Letter from Rencurrel, D.W., STPNOC, “South Texas Project, Units 1 and 2, Response to Requests for Additional Information (Set 5) for the License Renewal Application” (ADAMS Accession No. ML11334A047)
11/21/2011	Letter from Rencurrel, D.W., STPNOC, “South Texas Project, Units 1 and 2, Response to Requests for Additional Information for the License Renewal Application” (ADAMS Accession No. ML11335A131)
12/6/2011	Letter to Rencurrel, D.W., STPNOC, “Requests for Additional Information for the Review of the South Texas Project, Units 1 and 2, License Renewal Application—Aging Management, Set 9 (TAC Nos. ME4936 and ME4937)” (ADAMS Accession No. ML11312A176)
12/6/2011	Meeting Summary, Daily, J.W., “Summary of Telephone Conference Call Held on November 17, 2011, Between the U.S. Nuclear Regulatory Commission and STP Nuclear Operating Company, Concerning Clarifications to Some Responses to Requests for Additional Information—South Texas Project” (ADAMS Accession No. ML11335A076)
12/6/2011	Letter from Rencurrel, D.W., STPNOC, “South Texas Project, Units 1 and 2, Response to Requests for Additional Information for the License Renewal Application Aging Management Program, Set 7 (TAC Nos. ME4936 and ME4937)” (ADAMS Accession No. ML11346A012)
12/7/2011	Letter from Rencurrel, D.W., STPNOC, “South Texas Project Units 1 and 2, Supplement to the South Texas Project License Renewal Application (TAC Nos. ME4936 and ME4937)” (ADAMS Accession No. ML11347A365)
12/8/2011	Letter from Rencurrel, D.W., STPNOC, “South Texas Project, Units 1 and 2, Supplement to the License Renewal Application” (ADAMS Accession No. ML11354A087)
12/14/2011	Letter to Rencurrel, D.W., STPNOC, “Requests for Additional Information for the Review of the South Texas Project, Units 1 and 2, License Renewal Application—Aging Management, Set 10 (TAC Nos. ME4936 and ME4937)” (ADAMS Accession No. ML11332A100)
12/15/2011	Letter from Rencurrel, D.W., STPNOC, “South Texas Project, Units 1 and 2, Response to Requests for Additional Information for the Renewal Application” (ADAMS Accession No. ML11362A080)
12/15/2011	Letter from Rencurrel, D.W., STPNOC, “South Texas Project, Units 1 and 2, Response to Request for Additional Information to the License Renewal Application” (ADAMS Accession No. ML11362A081)
1/5/2012	Letter from Powell, G.T., STPNOC, “South Texas Project, Units 1 and 2, Response to Requests for Additional Information for License Renewal Application Aging Management, Set 9” (ADAMS Accession No. ML12013A206)
1/10/2012	Letter from Harrison, A.W., STPNOC, “South Texas Project, Units 1 and 2, Clarification of Information in Support of the Review of the License Renewal Application” (ADAMS Accession No. ML12011A188)

Document Date	Title
1/10/2012	Letter from Harrison, A.W., STPNOC, “South Texas Project, Units 1 and 2, License Renewal Application, Revised Scoping Drawing” (ADAMS Accession No. ML120470225)
1/18/2012	Letter from Rencurrel, D.W., STPNOC, “South Texas Project, Units 1 and 2, Response to Requests for Additional Information for the License Renewal Application, Aging Management Program, Set 10” (ADAMS Accession No. ML12020A072)
1/26/2012	Letter from Rencurrel, D.W., STPNOC, “South Texas Project, Units 1 and 2, Transmittal of Errata Associated with the South Texas Project License Renewal Application” (ADAMS Accession No. ML12033A155)
1/30/2012	Letter to Rencurrel, D.W., STPNOC, “Requests for Additional Information for the Review of the South Texas Project, Units 1 and 2, License Renewal Application—Aging Management, Set 11 (TAC Nos. ME4936 and ME4937)” (ADAMS Accession No. ML12030A164)
2/6/2012	Letter from Rencurrel, D.W., STPNOC, “South Texas Project, Units 1 and 2, Response to Requests for Additional Information for License Renewal Application, Aging Management Program, Set 10 (RAI 4.7.3-2) (TAC Nos. ME4936 and ME4937)” (ADAMS Accession No. ML12041A170)
2/8/2012	Letter to Rencurrel, D.W., STPNOC, “Request for Additional Information for the Review of the South Texas Project, License Renewal Application—Aging Management, Set 12 (TAC Nos. ME4936 and ME4937) STP RAI, Set 12 Draft” (ADAMS Accession No. ML12009A117)
2/9/2012	Meeting Summary, Daily, J.W., “STP—Record of Conference Call January 10, 2012, Regarding Aluminum-Bronze RAI Responses.docx” (ADAMS Accession No. ML12011A009)
2/16/2012	Meeting Summary, Daily, J.W., “Summary of Telephone Conference Call Held on January 4, 2012, Between the NRC and STP Nuclear Operating Company, Regarding Clarifications on Containment Tendon Prestress and One Request for Additional Information, for the South Texas Project, Units 1 and 2” (ADAMS Accession No. ML12011A008)
2/16/2012	Letter to Rencurrel, D.W., STPNOC, “Plan for the Aluminum Bronze Aging Management Program Regulatory Audit Regarding the South Texas Project, Units 1 and 2, License Renewal Application Review (TAC Nos. ME4936 and ME4937)” (ADAMS Accession No. ML12039A054)
2/16/2012	Letter from Rencurrel, D.W., STPNOC, “South Texas Project, Units 1 and 2, Response to Requests for Additional Information for the South Texas Project License Renewal Application—Aging Management Program, Set 11” (ADAMS Accession No. ML12053A258)
2/27/2012	Letter from Rencurrel, D.W., STPNOC, “South Texas Project, Units 1 and 2, Response to Requests for Additional Information for the South Texas Project License Renewal Application—Aging Management Program, Set 12 (TAC Nos. ME4936 and ME4937)” (ADAMS Accession No. ML12069A024)
2/28/2012	Letter to Rencurrel, D.W., STPNOC, “Requests for Additional Information for the Review of the South Texas Project, Units 1 and 2, License Renewal Application—Aging Management, Set 14 (TAC Nos. ME4936 and ME4937)” (ADAMS Accession No. ML12053A430)
3/5/2012	Letter from Rencurrel, D.W., STPNOC, “South Texas Project, Units 1 and 2, Revised Response to Requests for Additional Information for the South Texas Project License Renewal Application—Aging Management Program, Set 10 (RAI 4.7.3-2) (TAC Nos. ME4936 and ME4937)” (ADAMS Accession No. ML12073A106)
3/12/2012	Letter from Powell, G.T., STPNOC, “South Texas Project, Units 1 and 2, Response to Requests for Additional Information for the Review of the South Texas Project License Renewal Application” (ADAMS Accession No. ML12079A014)
3/12/2012	Letter from Powell, G.T., STPNOC, “South Texas Project, Units 1 and 2, Response to Requests for Additional Information for the License Renewal Application—Aging

Document Date	Title
	Management Program, Set 13" (ADAMS Accession No. ML12079A015)
3/21/2012	Letter to Rencurrel, D.W., STPNOC, "Requests for Additional Information for the Review of the South Texas Project, Units 1 and 2, License Renewal Application—Aging Management, Set 15 (TAC Nos. ME4936 and ME4937) STP-RAIs-Set 15-letter" (ADAMS Accession No. ML12065A201)
3/28/2012	Letter from Rencurrel, D.W., STPNOC, "South Texas Project, Units 1 and 2, Response to Requests for Additional Information for the South Texas Project License Renewal Application—Aging Management Program, Set 14" (ADAMS Accession No. ML12097A064)
3/29/2012	Letter from Rencurrel, D.W., STPNOC, "South Texas Project, Units 1 and 2, Supplemental Response to Requests for Additional Information for the South Texas Project License Renewal Application—Aging Management Program, Set 13 and Set 14" (ADAMS Accession No. ML12097A065)
4/3/2012	Meeting Summary, Daily, J.W., "Summary of Telephone Conference Call Held on January 30, 2012, Between the U.S. Nuclear Regulatory Commission and STP Nuclear Operating Company, Regarding Requests for Information on Flow-Accelerated Corrosion and Others, for the South Texas Project" (ADAMS Accession No. ML12067A243)
4/11/2012	Meeting Summary, Daily, J.W., "STP—Record of Conference Call Held on February 16, 2012, Regarding RAIs-RVIs-31180-etc." (ADAMS Accession No. ML12080A040)
4/11/2012	Meeting Summary, Daily, J.W., "STP—Record of Conference Call Held on February 9, 2012, Regarding RAIs—TLAAs" (ADAMS Accession No. ML12080A044)
4/11/2012	Meeting Summary, Daily, J.W., "STP—Record of Conference Call Held on March 1, 2012, Regarding RAIs—RV Beltline" (ADAMS Accession No. ML12080A049)
4/11/2012	Meeting Summary, Daily, J.W., "STP—Record of Conference Call Held on March 8, 2012, Regarding RAIs-SGTI-RxHeadStudClosures" (ADAMS Accession No. ML12080A055)
4/12/2012	Letter to Rencurrel, D.W., STPNOC, "Requests for Additional Information for the Review of the South Texas Project, Units 1 and 2, License Renewal Application—Aging Management, Set 16 (TAC Nos. ME4936 and ME4937)" (ADAMS Accession No. ML12087A141)
4/17/2012	Letter from Rencurrel, D.W., STPNOC, "Response to Requests for Additional Information for the South Texas Project License Renewal Application—Aging Management Program, Set 13 (Supplemental) and Set 15 (TAC Nos. ME4936 and ME4937)" (ADAMS Accession No. ML12114A231)
4/19/2012	Meeting Summary, Daily, J.W., "Summary of Telephone Conference Call Held January 18, 2012, Between the U.S. Nuclear Regulatory Commission and STP Nuclear Operating Company, Regarding Applicant Response Related to High-Strength Bolts, for the South Texas Project, Units 1 and 2" (ADAMS Accession No. ML12067A127)
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Document Date	Title
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APPENDIX C

PRINCIPAL CONTRIBUTORS

Name	Responsibility
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Andersen, J.	Management Oversight
Armstrong, G.	Reviewer—Scoping & Screening Methodology
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Buford, A.	Reviewer—Structural
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Delagatti, M.	Management Oversight
Dennig, R.	Management Oversight
Desai, K.	Reviewer—Mechanical
Doutt, C.	Reviewer—Electrical
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Evans, M.	Management Oversight
Fairbanks, C.	Reviewer—Mechanical
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Sun, R.	Reviewer—Mechanical
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Advanced Technologies and Laboratories International, Inc.	Technical Review

Contractor	Technical Area
Center for Nuclear Waste Regulatory Analysis	Technical Review
Oak Ridge National Laboratories	Technical Review
Ian, Evan & Alexander Corporation	SER Support

APPENDIX D

REFERENCES

This appendix contains a listing of the references used in the preparation of the safety evaluation report (SER) prepared during the review of the license renewal application (LRA) for South Texas Project (STP), Units 1 and 2, Docket Numbers 50-498 and 50-499.

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