Safety Evaluation Report

Related to the License Renewal of Callaway Plant, Unit 1

Docket No. 50-483

Union Electric Company (Ameren Missouri)

United States Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

August 2014

ABSTRACT

This safety evaluation report (SER) documents the technical review of the Callaway Nuclear Plant, Unit 1 (Callaway), license renewal application (LRA) by the United States (U.S.) Nuclear Regulatory Commission (NRC) staff (the staff). By letter dated December 15, 2011, Union Electric Company, doing business as Ameren Missouri (Ameren Missouri or the applicant), submitted the LRA in accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants." Ameren Missouri requests renewal of the Callaway operating license (Operating License No. NPF-30) for a period of 20 years beyond the current expiration at midnight October 18, 2024.

Callaway is located approximately 25 miles east-northeast of Jefferson City, Missouri. The NRC issued the Callaway construction permit on April 16, 1976, and operating license on October 18, 1984. Callaway is of a pressurized-water reactor design. Westinghouse Electric Corporation designed and supplied the nuclear steam supply system, and General Electric Company designed and supplied the turbine generator. The containment is a carbon steel-lined, concrete structure designed by Bechtel Power Corporation. The Callaway licensed power output is 3,565 megawatts thermal.

Unless otherwise indicated, this SER presents the status of the staff's review of information submitted through June 20, 2014, the cutoff date for consideration in the SER. The five open items previously identified by the staff for the SER with Open Items, issued April 23, 2013, have been closed (see SER Section 1.5); therefore, no open items remain to be resolved before the final determination is reached by the staff on the LRA.

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ABBREVIATIONS

°C degree Celsius
°F degree Fahrenheit
ΔT temperature change
σ standard deviation
$3S_M$ primary plus secondary stress intensity

A/LAIs applicant or licensee action item
ACI American Concrete Institute
ACSR aluminum conductors, steel reinforced
ADAMS Agencywide Documents Access and Management System
AERM aging effect requiring management
AISC American Institute of Steel Construction
AMP Aging Management Program
AMR Aging Management Review
ANS American Nuclear Society
ANSI American National Standards Institute
ASCE American Society of Civil Engineers
ASI accumulator safety injection
ASME American Society of Mechanical Engineers
ASTM American Society for Testing and Materials
ATWS anticipated transient without scram
AVB anti-vibration bar

B&PV boiler and pressure vessel
B&W Babcock and Wilcox
BMI bottom-mounted instrument
BRWS borated refuel water storage
BTR boron thermal regeneration

CAP Corrective Action Program
CAR Callaway Action Request
CASS cast austenitic stainless steel
CBF cycle-based fatigue
CCW component cooling water
CEL Callaway Equipment List
CETNA core exit thermocouple nozzle assembly
CF chemistry factor
CFR *Code of Federal Regulations*
CLB current licensing basis
CMMA Crane Manufacturers Association of America
CMTR certified materials test report
COMS cold overpressure mitigation system
CRDM control rod drive mechanism
CRGT control rod guide tube
CST condensate storage tank
Cu copper
CUF cumulative usage factor

CUF_{en} environmentally adjusted fatigue usage factor
CVC chemical and volume control
CVCS chemical and volume control system

DBE design-basis event

EAF environmentally assisted fatigue
ECC emergency core cooling
EDG emergency diesel generator
EFPY effective full power year
EMA equivalent margins analysis
EOF emergency operations facility
EOL end-of-life
EOLE end-of-life-extended
EPRI Electric Power Research Institute
ESF engineered safety features
ESW essential service water
EQ environmental qualification

F_{en} environmental adjustment factor
FAC flow-accelerated corrosion
FMECA failure modes, effects, and criticality analysis
FSAR final safety analysis report
FWST fire water storage tank

GALL generic aging lessons learned
GL generic letter
gpm gallon per minute
GSI generic safety issue
GTAW gas tungsten arc weld

HDPE high-density polyethylene
HELB high-energy line break
HPCI high-pressure coolant injection
HVAC heating, ventilation, and air-conditioning

I&C instrumentation and controls
IASCC irradiated-assisted stress-corrosion cracking
ICI incore instrumentation
IEEE Institute of Electrical and Electronic Engineers
ILRT integrated leak rate test
IN information notice
IPA integrated plant assessment
ISI inservice inspection

K_{IA} crack arrest fracture toughness parameter
K_{IC} static crack initiation fracture toughness parameter

L_a allowable leakage rate
LAR license amendment request
LBB leak-before-break

LCO limiting condition of operation
LERF large early release frequency
LLRT local leak rate tests
LOCA loss-of-coolant accident
LRA license renewal application
LTOP low-temperature overpressure protection

MC metal containment
MeV million electron volts
MIC microbiologically influenced corrosion
MOP modified operating procedure
MRP Materials Reliability Program
MRV minimum required value
mV millivolt
MXPLR maximum path leakage rate

NACE National Association of Corrosion Engineers
NDE nondestructive evaluation
NEI Nuclear Energy Institute
NFPA National Fire Protection Association
Ni nickel
NPS nominal pipe size
NRC U.S. Nuclear Regulatory Commission

OBE operating basis earthquake
ORNL Oak Ridge National Laboratory

P-T pressure-temperature
PLL predicted lower limit
PORV power operated relief valve
ppb parts per billion
ppm parts per million
PTLR P-T Limits Report
PTS pressurized thermal shock
PVC polyvinyl chloride
PWR pressurized water reactor
PWSCC primary water stress-corrosion cracking
QA quality assurance

RAI request for additional information
RCCA rod cluster control assembly
RCP reactor coolant pump
RCPB reactor coolant pressure boundary
RCS reactor coolant system
RFO refueling outage
RG Regulatory Guide
RHR residual heat removal
RI-ISI risk-informed inservice inspection
RIS regulatory issue summary
RPV Reactor pressure vessel
RSG replacement steam generator

RT_{NDT} nil-ductility reference temperature
RT_{PTS} reference temperature for PTS
RVI reactor vessel internal
RVID RVI database
RWST refueling water storage tank

S_a alternating stress intensity
SA site addendum
SAC stranded aluminum conductor
SAW submerged arc welding
SBF stress-based fatigue
SBO station blackout
SC structure and component
SCC stress-corrosion cracking
SCCM standard cubic centimeters per minute
SE safety evaluation
SER safety evaluation report
SMAW shielded metal arc welding
SNUPPS standardized nuclear unit power plant system
SP standard plant
SRP-LR standard review plan—license renewal
SSC structure, system, and component
SSE safe-shutdown earthquake
SWOL structural weld overlay

TLAA time-limited aging analysis
TS technical specification
TSC technical support center
TSP tube support plate

UHS ultimate heat sink
UPA upper plenum anomaly
USE upper-shelf energy
UT ultrasonic test

V volt

WCAP Westinghouse Commercial Atomic Power

SECTION 1

INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

This document is a safety evaluation report (SER) on the license renewal application (LRA) for Callaway Plant, Unit 1 (Callaway), as filed by Union Electric Company, doing business as Ameren Missouri (Ameren Missouri or the applicant). By letter dated December 15, 2011, Ameren Missouri submitted its application to the U.S. Nuclear Regulatory Commission (NRC) for renewal of Callaway's operating license for an additional 20 years. The NRC staff (the staff) prepared this report to summarize the results of its safety review of the LRA for compliance with Title 10, Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," of the *Code of Federal Regulations* (10 CFR Part 54). The NRC project manager for the license renewal review is John Daily. Mr. Daily may 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:

Division of License Renewal
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001
Attention: John Daily, Mail Stop O11F1

In its December 15, 2011, submission letter, the applicant requested renewal of the operating license issued under Section 103 (Operating License No. NPF-30) of the Atomic Energy Act of 1954, as amended, for Callaway for a period of 20 years beyond the current expiration at midnight October 18, 2024. Callaway is located approximately 25 miles east-northeast of Jefferson City, MO. The NRC issued the Callaway construction permit on April 16, 1976, and operating license on October 18, 1984. Callaway is a pressurized-water reactor (PWR) design. Westinghouse Electric Corporation designed and supplied the nuclear steam supply system, and General Electric Company designed and supplied the turbine generator. The containment is a carbon steel-lined, concrete structure designed by Bechtel Power Corporation. The Callaway licensed power output is 3,565 megawatts thermal. The final safety analysis report (FSAR) shows details of the plant and the site.

The license renewal process consists of two concurrent reviews, a technical review of safety issues and an environmental review. The NRC regulations in 10 CFR Part 54 and 10 CFR Part 51, "Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions," respectively, set forth requirements for these reviews. The safety review for the Callaway license renewal is based on the applicant's LRA and 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 June 20, 2014. The staff reviewed information received after this date depending on the stage of the safety review and the volume and complexity of the information.

The public may view the LRA and all pertinent information and materials, including the FSAR, at the NRC Public Document Room located on the first floor of One White Flint North, 11555 Rockville Pike, Rockville, MD 20852-2738 (301-415-4737/800-397-4209); and at the Callaway County Public Library, 710 Court Street, Fulton, MO 65251. 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 Callaway's proposed operation for an additional 20 years beyond the term of the current operating license. The staff reviewed the LRA in accordance with NRC regulations and the guidance in NUREG-1800, Revision 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 license. SER Appendix B is a chronology of the principal correspondence between the staff and the applicant regarding the LRA review. SER Appendix C is a list of principal contributors to the SER, and Appendix D is a bibliography of the references in support of the staff's review.

In accordance with 10 CFR Part 51, the staff is 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 Callaway. The staff plans to issue a draft and final plant-specific GEIS Supplement.

1.2 License Renewal Background

In accordance with the Atomic Energy Act of 1954, as amended, and NRC regulations, operating licenses for commercial power reactors are issued for 40 years and can be renewed for up to 20 additional years. The original 40-year license term was selected based on economic and antitrust considerations rather than on technical limitations; however, some individual plant and equipment designs may have been engineered for an expected 40-year service life.

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

In 1991, the staff published 10 CFR Part 54, the License Renewal Rule (Volume 56, page 64943, of the *Federal Register* (FR) (56 FR 64943), dated December 13, 1991). The staff participated in an industry-sponsored demonstration program to apply 10 CFR Part 54 to a pilot plant and to gain the experience necessary to develop implementation guidance. To establish a scope of review for license renewal, 10 CFR Part 54 defined age-related degradation unique to license renewal; however, during the demonstration program, the staff found that adverse aging effects on plant systems and components are managed during the period of initial license and that the scope of the review did not allow sufficient credit for management programs, particularly the implementation of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," which regulates management of plant-aging

phenomena. As a result of this finding, the staff amended 10 CFR Part 54 in 1995. As published May 8, 1995, in 60 FR 22461, amended 10 CFR Part 54 establishes a regulatory process that is simpler, more stable, and more predictable than the previous 10 CFR Part 54. In particular, as amended, 10 CFR Part 54 focuses on the management of adverse aging effects rather than on the identification of age-related degradation unique to license renewal. The staff made these rule changes to ensure that important systems, structures, and components (SSCs) will continue to perform their intended functions during the period of extended operation. In addition, the amended 10 CFR Part 54 clarifies and simplifies the integrated plant assessment process to be consistent with the revised focus on passive, long-lived structures and components (SCs).

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

1.2.1 Safety Review

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

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

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

In implementing these two principles, 10 CFR 54.4, “Scope,” defines the scope of license renewal as including those SSCs that (1) are safety-related, (2) could affect safety-related functions in the event of failure, or (3) are relied on to demonstrate compliance with the NRC’s regulations for fire protection, environmental qualification, pressurized thermal shock, anticipated transient without scram, and station blackout.

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

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

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

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

In the LRA, the applicant made full use of the process defined in NUREG-1801, Revision 2, "Generic Aging Lessons Learned (GALL) Report," dated December 2010. The GALL Report summarizes staff-approved aging management programs (AMPs) for many SCs subject to an AMR. If an applicant commits to implementing these staff-approved AMPs, the time, effort, and resources for LRA review can be greatly reduced, improving the efficiency and effectiveness of the license renewal review process. The GALL Report summarizes the aging management evaluations, programs, and activities credited for managing aging for most of the SCs used throughout the industry. The report is also a quick reference for both applicants and staff reviewers to AMPs and activities that can adequately manage aging during the period of extended operation.

1.2.2 Environmental Review

Part 51 of 10 CFR contains regulations on environmental protection. In December 1996, the staff revised the environmental protection regulations to facilitate the environmental review for license renewal. The staff prepared the GEIS to document its evaluation of possible environmental impacts associated with nuclear power plant license renewals. For certain types of environmental impacts, the GEIS contains generic findings that apply to all nuclear power plants and are codified in Appendix B, "Environmental Effect of Renewing the Operating License of a Nuclear Power Plant," to Subpart A, "National Environmental Policy Act - Regulations Implementing Section 102(2)," of 10 CFR Part 51. In accordance with 10 CFR 51.53(c)(3)(i), a license renewal applicant may incorporate these generic findings in its environmental report. In accordance with 10 CFR 51.53(c)(3)(ii), an environmental report also must include analyses of environmental impacts that must be evaluated on a plant-specific basis (i.e., Category 2 issues).

In accordance with the National Environmental Policy Act of 1969 and 10 CFR Part 51, the staff reviewed the plant-specific environmental impacts of license renewal, including whether there was new and significant information not considered in the GEIS. As part of its scoping process, the staff held a public meeting on March 14, 2012, at Fulton City Hall, to identify plant-specific environmental issues. The draft, plant-specific GEIS Supplement 51, issued in February, 2014, documents the results of the environmental review and makes a preliminary recommendation as to the license renewal action. Another public meeting was held on March 19, 2014, in Fulton, MO, to discuss the draft, plant-specific GEIS Supplement. The staff plans to publish the final, plant-specific GEIS Supplement 51 separately from this report, after considering comments on the draft.

1.3 Principal Review Matters

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

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

In accordance with 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 in the LRA:

> 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-93 between Ameren Missouri and the NRC ("Indemnity Agreement") in Article VII states "The term of this agreement shall commence … and 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 SNM-1901, NPF-25, and NPF-30.
>
> Ameren Missouri requests that conforming changes be made to the Indemnity Agreement, as amended, and/or the Attachment to said 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. Based on the current language contained in the Indemnity Agreement that is cited above, Ameren Missouri believes that no changes are 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.

In accordance with 10 CFR 54.21, "Contents of Application – Technical Information," the NRC requires that the LRA contain (a) an integrated plant assessment, (b) a description of any CLB changes during the staff's review of the LRA, (c) an evaluation of TLAAs, and (d) an FSAR supplement. LRA Sections 3 and 4 and Appendix B address the license renewal requirements of 10 CFR 54.21(a), (b), and (c). LRA Appendix A satisfies the license renewal requirements of 10 CFR 54.21(d).

In accordance with 10 CFR 54.21(b), the NRC requires that, each year following submission of the LRA and at least three months before the scheduled completion of the staff's review, the applicant submit an LRA amendment identifying any CLB changes to the facility that affect the contents of the LRA, including the FSAR supplement. By letters dated December 19, 2012, and December 20, 2013, the applicant submitted LRA updates which together summarize CLB

changes that have occurred during the staff's review of the LRA. These submissions satisfy 10 CFR 54.21(b) requirements.

In accordance with 10 CFR 54.22, "Contents of Application - Technical Specifications," the NRC requires that the LRA include changes or additions to the technical specifications (TS) that are necessary to manage aging effects during the period of extended operation. In LRA Appendix D, the applicant stated that it had not identified any TS changes necessary for issuance of the renewed Callaway operating license. This statement adequately addresses the 10 CFR 54.22 requirement.

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

As required by 10 CFR 54.25, "Report of the Advisory Committee on Reactor Safeguards," the ACRS will issue a report documenting its evaluation of the staff's LRA review and SER. SER Section 5 is reserved for the ACRS report when it is issued. SER Section 6 documents the findings required by 10 CFR 54.29.

1.4 Interim Staff Guidance

License renewal is a living program. The staff, industry, and other interested stakeholders gain experience and develop lessons learned with each renewed license. The lessons learned help the staff work toward its performance goals of maintaining safety, improving effectiveness and efficiency, reducing regulatory burden, and increasing public confidence. Interim staff guidance (ISG) is documented for use by the staff, industry, and other interested stakeholders until incorporated into such license renewal guidance documents as the SRP-LR and the GALL Report.

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

Table 1.4-1 Current Interim Staff Guidance

ISG Issue (Approved ISG Number)	Purpose	SER Section
"Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation" (LR-ISG-2012-02)	This LR-ISG gives guidance on aging management for internal surfaces, fire water system, atmospheric storage tanks, and corrosion under insulation.	SER Sections 3.0.2.2.9, 3.2.2.3.6, 3.3.2.1.4, 3.3.2.2.8, 3.3.2.3.4, 3.3.2.3.10, 3.3.2.3.26, 3.4.2.2.1, 3.4.2.2.6, and 3.4.2.3.2
"Wall Thinning Due to Erosion Mechanisms" (LR-ISG-2012-01)	This LR-ISG modifies the guidance provided in GALL Report AMP XI.M17 by allowing the Flow-Accelerated Corrosion program to also manage wall thinning due to erosion mechanisms if these mechanisms are not being managed through another program.	SER Sections 3.2.2.1.1, 3.3.2.1.17, and 3.4.2.1.1
"Ongoing Review of Operating Experience" (LR-ISG-2011-05)	This LR-ISG clarifies the staff's existing position in the SRP-LR that acceptable license renewal AMPs should be informed and enhanced when necessary, based on the ongoing review of both plant-specific and industry operating experience.	SER Section 3.0.5
"Updated Aging Management Criteria for Reactor Vessel Internal Components of Pressurized Water Reactors" (LR-ISG-2011-04)	This LR-ISG provides guidance to assist PWR license renewal applicants in adequately addressing MRP-227-A recommendations related to aging management of reactor vessel internal components during the term of the renewed license.	SER Section 3.0.3.1.5
"Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program (AMP) XI.M41, 'Buried and Underground Piping and Tanks'" (LR-ISG-2011-03)	This LR-ISG provides changes to GALL Report AMP XI.M41. The AMP, as modified in this LR-ISG, provides one acceptable approach for managing the effects of aging of buried and underground piping and tanks within the scope of the License Renewal Rule.	SER Section 3.0.3.2.14
"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 3.0.3.1.7
"Aging Management of Stainless Steel Structures and Components in Treated Borated Water" (LR-ISG-2011-01)	This LR-ISG provides guidance as 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 the License Renewal Rule.	SER Sections 3.2.2.1.1, 3.2.2.1.2, 3.2.2.1.3, 3.3.2.1.1, 3.3.2.1.2, 3.3.2.1.3, and 3.3.2.1.16

1.5 Summary of Open Items

As a result of its review of the LRA, including additional information submitted through June 20, 2014, the staff closed the following open items previously identified in the "Safety Evaluation Report with Open Items Related to the License Renewal of Callaway Plant, Unit 1," dated April 2013 (ADAMS Accession No. ML13086A224). The staff has identified no other open items (OIs). An item is considered open if the staff has not made a finding under 10 CFR 54.29, "Standards for issuance of a renewed license," with respect to that particular item. A summary of each closed OI is presented here.

Open Item 2.3.3.20-1 Scoping of Fire Protection SSCs

As parts of its evaluation of the applicant's compliance with 10 CFR 50.48, "Fire protection," the staff reviewed the following fire protection documents cited in the CLB listed in Callaway Operating License Condition 2.C(5):

- NUREG-0830, "Safety Evaluation Report Related to the Operation of Callaway Plant, Unit No 1," October 1981
- NUREG-0830, Supplement No 3, "Safety Evaluation Report Related to the Operation of Callaway Plant, Unit No. 1," May 1984

By letter dated June 11, 2012, the staff issued RAI 2.3.3.20-1 requesting, in part, that the applicant confirm if the fire suppression SSCs in (a) the auxiliary boiler room; (b) the turbine building north area below turbine at Elevations 2000'-0'' and 2033'-0'' and south area below turbine at Elevations 2000'-0'' and 2033'-0''; and (c) the turbine generator bearing, condenser pit, and hydrogen seal oil unit are within the scope of license renewal in accordance with 10 CFR 54.4(a). If water systems and components were excluded from the scope of license renewal and not subject to an AMR, the staff requested that the applicant provide justification for the exclusion.

The applicant responded to the RAI by stating that the above fire suppression SSCs are not within the scope of license renewal because they are not required to function to suppress a fire or are not required for compliance with 10 CFR 50.48.

The staff disagrees with excluding the above fire suppression SSCs from the scope of license renewal and disagrees with the applicant's basis (that they are not required to function to suppress a fire or are not required for compliance with 10 CFR 50.48). This exclusion is contrary to the FSAR, which includes the original Callaway fire protection safety evaluation, NUREG-0830, "Safety Evaluation Report related to the Operation of Callaway Plant, Unit No. 1," dated October 1981, as the CLB.

In addition, by letter dated August 29, 2011, the applicant submitted a license amendment request (LAR) to transition the existing Fire Protection Program for Callaway to a risk-informed, performance-based program based on National Fire Protection Association Standard (NFPA) 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants," 2001 Edition, in accordance with 10 CFR 50.48(c). Following the NFPA 805 LAR, the applicant submitted to the staff, by letter dated December 15, 2011, an LRA for renewal of Operating License NPF-30 for Callaway.

It is unclear to the staff what are the Fire Protection Program plant modifications planned for transition to NFPA 805 that may affect the existing Fire Protection Program SSCs within the

scope for license renewal. Therefore, the staff requested the applicant to identify and discuss the changes associated with the NFPA 805 transition, provide a gap analysis of the LRA Tables 2.3.3-20 and 3.3.2-20 identifying any differences between the existing plant configuration and NFPA 805 post-transition configuration, and provide a list of the fire protection SSCs which will be added to or removed from, based on the NFPA 805 transition, the scope of license renewal in accordance with 10 CFR 54.4(a). The applicant stated that the Callaway NFPA 805 LAR is presently under the staff's review and is subject to change as a result of those reviews. The applicant committed (Commitment No. 39) to perform the requested gap analysis upon issuance of the draft NFPA 805 SER. The staff finds that the applicant should not perform a gap analysis of LRA Tables 2.3.3-20 and 3.3.2-20 based on a draft NFPA 805 LAR SER. The staff finds that the gap analysis should be based on a final NFPA 805 LAR SER.

By letters dated April 29, 2013, February 14, 2014, and April 15, 2014, the applicant submitted the requested information to close this OI. The staff's evaluation and closure of this open item is documented in SER Section 2.3.3.20.

Open Item B2.1.3-1 Reactor Head Closure Studs

On multiple occasions the applicant's closure studs became stuck during stud installation or removal activities. Stuck stud removal operations resulted in damage to some of the corresponding reactor pressure vessel (RPV) flange hole threads. In addition, during refueling outage No. 8 (fall 1996), stud No. 18 became stuck with only partial RPV flange hole thread engagement and was left in place. The applicant proposes to use its existing Reactor Head Closure Stud Bolting Program and stated that the program is consistent with GALL Report AMP XI.M3, "Reactor Head Closure Stud Bolting." Due to its plant-specific operating experience, the staff issued multiple RAIs expressing concerns related to the adequacy of the applicant's existing program to manage the effects of aging of the closure studs.

Because the extent and rate of degradation were unknown, the staff was concerned that the existing Reactor Head Closure Stud Bolting Program may not be adequate to detect future wear, loss of materials, or assure that allowable stresses under the American Society of Mechanical Engineers (ASME) Code are not exceeded during the period of extended operation. The staff identified this as OI B2.1.3-1.

In its August 29, 2013, response, the applicant provided additional information to address the staff's concerns. The staff reviewed and accepted the applicant's response as documented in SER Section 3.0.3.1.3. In addition, the staff proposed License Condition No. 3 (see SER Section 1.7) regarding the applicant's implementation of Commitment Nos. 41 and 42. OI B2.1.3-1 is closed.

Open Item B2.1.6-1 Materials Reliability Program (MRP)-227-A Report Applicant/Licensee Action Items (A/LAIs)

The applicant's PWR Vessel Internals Program implements the guidance of Materials Reliability Program (MRP)-227-A, "PWR Reactor Internals Inspection and Evaluation Guideline," dated January 9, 2012, which includes the applicant's plant-specific responses to action items, conditions, and limitations identified in the NRC Safety Evaluation for MRP-227, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guideline (MRP-227, Revision 0)." During its review of the applicant's program and responses to applicant/licensee action items (A/LAI) for MRP-227-A, the following aspects were identified by the staff as requiring additional information:

A/LAI No. 1. By letter dated January 24, 2013, the applicant provided its response to RAI B2.1.6-4a proposing to address A/LAI No. 1 in a future submittal. The staff finds the applicant's response summary to A/LAI No. 1 insufficient because the applicant did not submit its evaluation to demonstrate that the MRP-227-A is applicable to Callaway. According to RIS 2011-07, Callaway is a "Category D" plant, and the staff expects the applicant to submit an AMP for vessel internals that is consistent with MRP-227-A for NRC staff review and approval.

A/LAI No. 5. By letter dated January 24, 2013, the applicant provided its response to RAI B2.1.6-4a indicating that it has replaced the hold-down spring with a martensitic stainless steel material. The staff is currently reviewing the applicant's response to determine whether stress relaxation is an applicable aging effect for the new component and material.

A/LAI No. 7. It was not evident to the staff which of the reactor vessel internal (RVI) components in the plant design were made from cast austenitic stainless steel (CASS) materials, or for each RVI component made from CASS, why the applicant would not need to provide a supporting flaw tolerance analysis, functionality analysis, or CASS susceptibility analysis as recommended for in A/LAI No. 7. The staff finds that the applicant has not provided a sufficient basis for concluding that A/LAI No. 7 is not applicable to its CLB and that a supporting flaw tolerance analysis, functionality analysis, or susceptibility analysis would not be performed and submitted for each RVI component that is made from a CASS.

A/LAI No. 8, Item (5). By letter dated January 24, 2013, the applicant provided its response to RAI B2.1.6-4a proposing to address A/LAI No. 8, Item (5) in a future submittal. The staff finds the applicant's response summary to A/LAI No. 8, Item (5) insufficient because the applicant did not clearly identify how it would address those CUF analyses for RVI components that are TLAAs for the impact of reactor coolant environment on metal fatigue. According to RIS 2011-07, Callaway is a "Category D" plant, and the staff expects the applicant to submit an AMP for vessel internals that is consistent with MRP-227-A for NRC staff review and approval. The staff noted that adequate responses to the A/LAI are necessary for the staff to determine if the applicant's AMP is consistent with GALL AMP XI.M16A and MRP-227-A.

The staff identified the need for complete responses to these A/LAIs as OI B2.1.6-1. The staff's evaluation and closure of this OI is documented in SER Section 3.0.3.1.5. OI B2.1.6-1 is closed.

Open Item B2.1.20-1 ASME Code Class 1 Small-Bore Socket Welds

Originally LRA Section B2.1.20 stated that there were 19 Class 1 small-bore socket welds in the population of ASME Code Class 1 piping less than 4-inches and greater than or equal to 1-inch nominal pipe size. However, during the audit the applicant stated that a recent recount, subsequent to the LRA submission, had indicated that there were 23 Class 1 small-bore socket welds within the scope of the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program. By letter dated July 18, 2012, the staff issued RAI B2.1.20-1, requesting that the applicant clarify the total population of ASME Code Class 1 socket welds within the scope of the AMP. In its response dated August 21, 2012, the applicant stated that there were 77 small-bore socket welds in the scope of the AMP. By a teleconference call held on April 11, 2013, the staff requested additional clarification from the applicant to explain the reasons for the large discrepancy between the different counting results for the number of socket welds, and whether any error in the process has been corrected.

The staff identified the socket weld question as OI B2.1.20-1. By letter dated April 16, 2013, the applicant supplemented its response to RAI B2.1.1.20-1; however, this response did not

address the staff's concerns. By letter dated July 12, 2013, the staff issued RAI B2.1.20-2, requesting that the applicant verify that the issue was entered into the applicant's corrective actions program. In its response dated August 2, 2013, the applicant confirmed that the issue was entered in the applicant's corrective actions program. The staff's evaluation and closure of this OI is documented in SER Section 3.0.3.1.9. OI B2.1.20-1 is closed.

Open Item 4.3.4-1 Effects of the Reactor Coolant System Environment on Fatigue Life of Piping and Components

Callaway performed a systematic review of all wetted, reactor coolant pressure boundary components with a Class 1 fatigue analysis to either show that the NUREG/CR-6260 locations are bounding or to incorporate environmentally assisted fatigue (EAF) into the licensing basis for those more limiting components. As described in SER Section 4.3.4.2, the staff has concerns on the approach taken by the applicant to address the effects of the reactor coolant system environment on fatigue life of piping and components.

The applicant performed a systematic review to determine the "sentinel" locations to be monitored by the Fatigue Monitoring Program for EAF. This systematic review involved ranking and comparisons of environmental fatigue usage. However, in justifying its systematic review, the applicant did not demonstrate that the values for environmental fatigue usage were based on a normalized scale; thus, the resulting ranking and comparisons may not have appropriately determined the "sentinel" locations. The applicant also provided examples of screening methods used to identify "sentinel" locations to be monitored by the Fatigue Monitoring Program for EAF. However, in justifying the screening methods with the plant-specific examples, the applicant did not demonstrate that the implementation of these screening methods were appropriate for Callaway. The staff's questions regarding EAF were identified as OI 4.3.2-1.

The staff's evaluation and closure of this OI is documented in SER Section 4.3.4. OI 4.3.4-1 is closed.

1.6 Summary of Confirmatory Items

As a result of its review of the LRA, including additional information submitted through June 20, 2014, the staff determines that no confirmatory items exist which would require a formal response from the applicant.

1.7 Summary of Proposed License Conditions

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

License Condition No. 1: The first license condition requires the applicant to include the FSAR supplement required by 10 CFR 54.21(d) in the next FSAR update, required by 10 CFR 50.71(e), following the issuance of the renewed license. The applicant may make changes to the programs and activities described in the FSAR 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.

License Condition No. 2: The second license condition will state that the applicant's FSAR supplement describes certain programs to be implemented and activities to be completed before the period of extended operation. The second license condition will also state that:

(a) The applicant shall implement those new programs and enhancements to existing programs no later than 6 months before the period of extended operation

(b) The applicant shall complete those inspection and testing activities before the end of the last refueling outage before the period of extended operation or 6 months before the period of extended operation, whichever occurs later

The second license condition will further state that the applicant shall notify the NRC in writing within 30 days after having accomplished item (a) above and include the status of those activities that have been or remain to be completed in item (b) above.

The purpose of requiring the completion of implementation, inspection, and testing either before the end of the last refueling outage or before the 6-month time frame is to ensure that the implementation of programs and completion of specific activities can be confirmed by the NRC's oversight process before the plant enters the period of extended operation.

LRA Section A4, Table A4-1, "License Renewal Commitments," contains commitments for license renewal and an associated schedule for when the applicant plans to implement or complete the commitments. The staff noted that through the commitments in LRA Section A4, Table A4-1, the applicant will implement new programs, implement enhancements to existing programs, and will also complete inspection or testing activities. The staff noted that the applicant's implementation schedule for some commitments, as provided originally in LRA Section A4, Table A4-1, may conflict with the implementation schedule intended by the generic second license condition described above. Therefore, by letter dated February 21, 2013, the staff issued RAI A4-1, Part (1), requesting the applicant to identify those commitments to implement new programs and enhancements to existing programs and state when the implementation of these programs will be completed. In addition, RAI A4-1, Part (2), requested the applicant to identify those commitments to complete inspection or testing activities and state when the completion of these inspection and testing activities will occur.

By letter dated February 28, 2013, the applicant provided its response to RAI A4-1. In response to RAI A4-1, Part (1), the applicant stated that it will complete implementation of new programs and enhancements to existing programs no later than 6 months before the period of extended operation. As part of its response, the applicant provided LRA Amendment 22 which revised LRA Appendix A.0, "Introduction," and the implementation schedule in LRA Table A4-1 for those commitments that implement new programs or enhance existing programs to state that these commitments will be completed no later than 6 months before the period of extended operation.

In response to RAI A4-1, Part (2), the applicant stated it will complete inspection and testing activities either 6 months before the period of extended operation or by the end of the last refueling outage before the period of extended operation, whichever occurs later. As part of its response, the applicant provided LRA Amendment 22, which revised LRA Appendix A.0, "Introduction," and the implementation schedule in LRA Table A4-1 for those commitments with inspection and testing activities to state that the inspection and testing activities related to these commitments will be completed 6 months before the period of extended operation or by the end of the last refueling outage before the period of extended operation, whichever occurs later. In addition, the applicant revised LRA Appendix A.0 to state that it shall notify the NRC in writing within 30 days after having accomplished item (a) of the proposed second license condition and will also include the status of those activities that have been or remain to be completed in item (b) of the proposed second license condition.

The staff finds the applicant response to RAI A4-1, Parts (1) and (2), acceptable because: (1) the staff reviewed the applicant's response and LRA Amendment 22 revision of LRA Appendix A, "Final Safety Analysis Report," and LRA Table A4-1 and confirmed that the applicant identified those commitments that implement new programs and enhancements to existing programs and stated that these commitments will be implemented no later than 6 months before the period of extended operation, which is consistent with the proposed second license condition; and (2) the staff also confirmed that as part of its response, in LRA Amendment 22, the applicant identified those commitments to complete inspection or testing activities and stated, consistent with the proposed second license condition, that these commitments will be implemented 6 months before the period of extended operation or by the end of the last refueling outage before the period of extended operation, whichever occurs later. Therefore, the staff's concerns described in RAI A4-1, Parts (1) and (2), are resolved.

License Condition No. 3: The third license condition will contain language requiring implementation of Commitment Nos. 41 and 42, which the applicant proposed in resolution to the stuck reactor vessel closure studs open item, OI B2.1.3-1. The license condition will address the following requirements:

- In order to ensure that the threads for RPV stud hole No.18 can perform their intended function throughout the period of extended operation, the license condition will require the applicant to remove stuck stud No. 18 prior to entering the period of extended operation.

- In order to ensure that the RPV stud holes with damaged threads can continue to perform their intended function throughout the period of extended operation, the license condition will require the applicant to perform a laser inspection for the threads of stud hole location Nos. 2, 4, 5, 7, 9, and 53. If inspection of these RPV stud holes reveals that there is additional degradation in any of these stud holes, the condition will be entered in the Corrective Action Program for evaluation and corrective action; in addition, the applicant shall inspect the remaining repaired RPV stud hole locations (Nos. 13, 25, 39 and 54).

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

2.1.2 Summary of Technical Information in the Application

LRA Section 2, "Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review and Implementation Results," provides the technical information required by 10 CFR 54.21(a).

LRA Section 2.1, "Scoping and Screening Methodology," describes the methodology that Union Electric Company, doing business as Ameren Missouri (the applicant), used to identify the SSCs at the Callaway Plant, Unit 1 (Callaway) within the scope of license renewal (scoping) and the SCs subject to an AMR (screening).

LRA Section 2.1.1, "Introduction," states, in part, that the applicant had considered the following in developing the scoping and screening methodology described in LRA Section 2:

- Part 54 of 10 CFR, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants" (the Rule)
- 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)

2.1.3 Scoping and Screening Program Review

The United States (US) Nuclear Regulatory Commission (NRC) (the staff) evaluated the applicant's 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 provide the basis for the acceptance criteria used by the staff to assess the adequacy of the scoping and screening methodology that the applicant used to develop the LRA:

- 10 CFR 54.4(a), as it relates to the identification of 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), as it relates to the methods the applicant used to identify plant SCs subject to an AMR

The staff reviewed the information in LRA Section 2.1 to confirm 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) and SCs that are subject to an AMR, in accordance with the requirements of 10 CFR 54.21(a).

In addition, the staff conducted a scoping and screening methodology audit at the Callaway facility located in Callaway County, Missouri, during the week of April 16–19, 2012. 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 methodology described in the LRA and the requirements of the Rule. The staff reviewed the project-level guidelines, topical reports, and implementing procedures that described the applicant's scoping and screening methodology. The staff conducted detailed discussions with the applicant on the implementation and control of the license renewal, the quality practices the applicant used during the LRA development, and the training of the applicant's staff that participated in the LRA development. On a sampling basis, the staff performed a review of scoping and screening results reports and supporting current licensing basis (CLB) information for the essential service water system and the turbine building. In addition, the staff performed walkdowns of selected portions of the essential service water system, essential service water pump house, emergency diesel generator (EDG) building, the turbine building, and the ultimate heat sink (UHS) basin, as part of the sampling review of the implementation of the applicant's 10 CFR 54.4(a)(2) scoping methodology.

2.1.3.1 Implementation Procedures and Documentation Sources for Scoping and Screening

2.1.3.1.1 Summary of Technical Information in the Application

The applicant had developed implementing procedures to identify SSCs within the scope of license renewal and SCs subject to an AMR to implement the processes described in LRA Sections 2 and 2.1. Additionally, the applicant's implementing procedures provided guidance on the review and consideration of CLB documentation sources relative to the requirements of 10 CFR 54.4 and 10 CFR 54.21.

LRA Section 2.1 listed the following information sources for the license renewal scoping and screening process:

- CLB documents
- Callaway equipment database
- Q-List
- engineering drawings

- topical reports
- site walkdown

2.1.3.1.2 Staff Evaluation

Scoping and Screening Implementing Procedures. The staff reviewed the applicant's scoping and screening methodology implementing procedures, including license renewal guidelines, documents and reports, as documented in the staff's audit report, to ensure the guidance is consistent with the requirements of the Rule, the SRP-LR, and Regulatory Guide (RG) 1.188, "Standard Format and Content for Applications to Renew Nuclear Plant Operating Licenses," which endorses the use of NEI 95-10. The staff determined that the overall process used to implement the 10 CFR Part 54 requirements described in the implementing procedures and AMRs is consistent with the Rule, the SRP-LR, and the endorsed industry guidance.

The applicant's implementing procedures contain guidance for determining plant SSCs within the scope of the Rule and 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 information contained in the LRA, including the implementation of the staff positions documented in the SRP-LR, and the information in the applicant's responses dated August 9, 2012, to the staff's requests for additional information (RAIs) 2.1-1, 2.1-2, 2.1-3, and 2.1-4, issued by letter dated July 9, 2012. SER Section 2.1.4.1.2 provides the staff's evaluation of the applicant's responses to RAIs 2.1-1, 2.1-2, and 2.1-3. SER Section 2.1.4.2.2 provides the staff's evaluation of the applicant response to RAI 2.1-4. 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 staff also determined that the methodology is sufficiently detailed in the implementing procedures to provide concise guidance on the scoping and screening process to be followed during the LRA activities.

Sources of Current Licensing Basis Information. Part 54.21(a)(3) of 10 CFR requires, for each structure and component determined to be subject to an AMR, demonstration 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. Part 54.3(a) of 10 CFR defines the CLB, 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 final safety analysis report (FSAR). 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 verify that the methodology is sufficiently comprehensive to identify SSCs within the scope of license renewal and as SCs requiring an AMR.

During the scoping and screening methodology audit, 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 staff reviewed pertinent information sources used by the applicant including the FSAR, CLB documents, equipment database, Q-List, engineering drawings, and topical reports.

During the audit, the staff discussed the applicant's administrative controls for the equipment database, Q-List, and the other information sources used to verify system information. These controls are described and implemented 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 staff determined that the applicant has established adequate measures to control the integrity and reliability of system identification and safety classification data; therefore, the information sources the applicant used during the scoping and screening process provided a controlled source of system and component data to support scoping and screening evaluations.

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 requirements of 10 CFR 54.4(a). The applicant's license renewal program guidelines provided a listing of documents used to support scoping evaluations. The staff determined that the design documentation sources, required to be used by the applicant's implementing procedures, provided sufficient information to ensure that the applicant identified SSCs to be included within the scope of license renewal consistent with the plant's CLB.

2.1.3.1.3 Conclusion

Based on its review of LRA Section 2.1, the scoping and screening implementing procedures, and the results from the scoping and screening audit, the staff concludes that the applicant's use of implementing procedures and consideration of document sources, including CLB information, is consistent with the Rule, the SRP-LR, and NEI 95-10 guidance and, therefore, is acceptable.

2.1.3.2 Quality Controls Applied to License Renewal Application Development

2.1.3.2.1 Staff Evaluation

The staff reviewed the quality controls used by the applicant to ensure that the scoping and screening methodology used to develop the LRA were adequate for the activity. The applicant used the following quality control processes during the LRA development:

- scoping and screening activities using approved documents and implementing procedures
- procedurally controlled databases to guide and support scoping and screening and to generate license renewal documents
- processes and procedures that incorporate preparation, review, comment, and owner acceptance
- incorporation of industry lessons learned
- inclusion of independent review by industry senior consultants, industry peer review, and review by the Onsite Review Committee in the LRA preparation process

The staff performed a review of implementing procedures and guides, examined the applicant's documentation of activities in reports, reviewed the applicant's activities performed to assess the quality of the LRA, and held discussions with the applicant's license renewal management and staff. The staff determined that the applicant's activities provide assurance that the LRA was developed consistent 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 are adequate to ensure that LRA development activities were performed in accordance with the applicant's license renewal program requirements.

2.1.3.3 Training

2.1.3.3.1 Staff Evaluation

The staff reviewed the training process used by the applicant for license renewal project personnel to confirm that it was appropriate for the activity. As outlined in the implementing procedures, the applicant had required training for personnel participating in the development of the LRA and used trained and qualified personnel to prepare the scoping and screening implementing procedures.

License renewal project personnel had been trained using applicant-approved license renewal project procedures and other relevant license renewal information, as appropriate to their functions. Training topics had included 10 CFR Part 54, relevant NRC and industry guidance documents, lessons learned from other nuclear power plant license renewals, and applicable implementing procedures.

The staff discussed training activities with the applicant's management and license renewal project personnel and performed a sampling review of applicable documentation. The staff determined that the applicant had developed and implemented adequate controls for the training of personnel performing LRA activities.

2.1.3.3.2 Conclusion

On the basis of discussions with the applicant's license renewal personnel responsible for the scoping and screening process and its review of selected documentation in support of the process, the staff concludes that the applicant developed and implemented adequate procedures to train personnel to implement the scoping and screening methodology described in the applicant's implementing procedures and the LRA.

2.1.3.4 Conclusion of Scoping and Screening Program Review

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

2.1.4 Plant Systems, Structures, and Components Scoping Methodology

LRA Section 2.1, "Scoping and Screening Methodology" describes the applicant's methodology used to identify SSCs within the scope of license renewal in accordance with 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 and support an intended function for responding to a design basis event (DBE), are nonsafety-related whose failure could prevent accomplishment of a safety-related function, or perform a function that demonstrates compliance with the NRC's regulations for fire protection (10 CFR 50.48), environmental qualification (EQ) (10 CFR 50.49), pressurized thermal shock (PTS) (10 CFR 50.61), anticipated transients without scram (ATWS) (10 CFR 50.62), or station blackout (SBO) (10 CFR 50.63).

LRA Section 2.1.1, "Introduction," states that the scoping methodology that the applicant used 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 Title 10 Part 54.4(a)(1) of the Code of Federal Regulations

2.1.4.1.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify SSCs included within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4(a)(1) in LRA Section 2.1.2.1, "10 CFR 54.4(a)(1)–Safety-related," which states that "Callaway plant-specific definitions of safety-related are provided in the FSAR Section 1.1.7 Standard Plant (SP) and the Maintenance Rule Program. These definitions are consistent with the definition of safety-related provided in 10 CFR 54.4(a)(1)."

2.1.4.1.2 Staff Evaluation

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

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

> The set of design basis events as defined in the rule is not limited to Chapter 15 (or equivalent) of the [FSAR]. Examples of design basis events 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 design basis events as defined in 10 CFR 50.49(b)(1) may be found in any chapter of the facility [FSAR], the Commission's regulations, NRC orders, exemptions, or license conditions within the CLB. These sources should also be reviewed to identify [SSCs] that are relied upon to remain functional during and following design basis events (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 (anticipated operational occurrences, design-basis accidents, external events, and natural phenomena) that were applicable to Callaway. The staff reviewed the applicant's basis documents that 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 Callaway FSAR and basis documents

discussed events such as internal and external flooding, tornadoes, and missiles. The staff concludes that the applicant's evaluation of DBEs was consistent with the SRP-LR.

The staff determined that 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 Callaway 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 essential service water system and the turbine building to provide additional assurance that the applicant adequately implemented its scoping methodology with respect to 10 CFR 54.4(a)(1). The staff verified that the applicant developed the scoping results for each of the sampled systems consistently with the methodology, identified the SSCs credited for performing intended functions, and adequately described the basis for the results, as well as the intended functions. The staff also confirmed that the applicant had identified and used pertinent engineering and licensing information to identify the SSCs required to be within the scope of license renewal in accordance with the 10 CFR 54.4(a)(1) criteria.

The staff determined that additional information would be required to complete its review. Therefore, by letter dated July 9, 2012, the staff issued RAI 2.1-1 which states, in part:

> During the on-site scoping and screening methodology audit, the staff determined that the applicant had used a plant equipment database, the Callaway Equipment List (CEL),[…] [which] contains a quality field "Q" used to identify safety-related SSCs included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). However, during the audit the staff determined that not all components identified as "Q" were included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1).

The staff requested the applicant to perform a review of this issue and provide a description of the process used to evaluate components identified as Q in the database and the basis for not including components identified as Q within the scope of license renewal in accordance with 10 CFR 54.4(a)(1).

In its response letter, dated August 9, 2012, the applicant stated, in part:

> During the scoping process, all components were considered to be safety-related if they had a Y flag in the Q-QUAL field of the CEL. After review of plant basis documents, if a component with a Y flag in the CEL Q-QUAL field appeared not to have a safety-related function, an additional review was conducted. If there was a basis in plant documentation such as the CLB or an engineering evaluation that the component does not have a safety-related function, then the component was not included within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1). For cases where a component has a Y flag in the

> Q-QUAL field but was determined not to have a safety-related function, a corrective action document was initiated.
>
> Since it is assumed during the initial scoping and screening that a component with a Y flag in the Q-QUAL field of the CEL has a safety-related function, all components with a Y flag were reviewed. Thus, this methodology did not preclude the identification of safety-related SSCs that should have been included within the scope of license renewal.

Based on its review, the staff finds the applicant's response to RAI 2.1-1 acceptable because the applicant evaluated all components identified as Q in the CEL to determine if the components had a safety-related function and included those that did within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). The staff's concern described in RAI 2.1-1 is resolved.

The staff determined that additional information would be required to complete its review. The staff noted that LRA Section 2.4-4 does not indicate that the turbine building contains safety-related SSCs. However, the applicable license renewal drawings indicated that safety-related portions of the main steam supply system, main feedwater system, and steam generator blowdown system are located within the turbine building. The staff noted that the applicant had performed an evaluation and concluded that the safety-related portions of the systems located within the turbine building were not included within the scope of license renewal, in accordance with 10 CFR 54.4(a)(1). Therefore, by letter dated July 9, 2012, the staff issued RAI 2.1-2 requesting that the applicant provide the basis for any determination to not include safety-related SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(1).

In its response dated August 9, 2012, the applicant stated that during the scoping process, all components were considered to be safety-related if they had a Y flag in the Q-QUAL field of the CEL. The applicant stated that 12 piping segments contained in the main steam supply system, main feedwater system, and steam generator blowdown system in the turbine building had Y flags. The applicant also stated that these piping segments extended from the auxiliary building through the auxiliary building-turbine building wall and into the turbine building. The applicant further stated that from a review of FSAR Section 3.6.2.1.1e, "High-Energy Piping in Containment Penetration Areas," and engineering evaluations, it was determined that the sections of the piping extending into the turbine building do not have a safety-related function. In addition, the applicant stated that the boundary drawings for the main steam supply system, steam generator blowdown system, and main feedwater system have been revised to indicate that the safety-related portion of these lines ends at the auxiliary building-turbine building wall.

The staff reviewed the response to RAI 2.1-2 and determined that the applicant had identified portions of the systems located in the turbine building that were flagged as Q in the CEL. The applicant had reviewed applicable information contained in the FSAR and engineering evaluations and determined that the portions of main steam supply system, main feedwater system, and steam generator blowdown system in the turbine building did not have a safety-related function, and that the safety-related to nonsafety-related interface for each system was located in the wall joining the safety-related auxiliary building and the nonsafety-related turbine building. The applicant further concluded that the portions of the main steam supply, main feedwater, and steam generator blowdown systems located in the turbine building were not included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). Furthermore, the applicant's response did not address whether the portion

of nonsafety-related pipe attached to the safety-related pipe at the safety-related to nonsafety-related interface located in the turbine building wall was included within the scope of license renewal to the first anchor, equivalent anchor, or bounding condition, past the safety-related to nonsafety-related interface, in accordance with 10 CFR 54.4(a)(2) and the process described in LRA Section 2.1.2.2, which indicates that the applicant followed the guidance of NEI 95-10.

On December 6, 2012, the staff held a conference call with the applicant to discuss the inclusion of nonsafety-related pipe attached to the safety-related pipe within the scope of license renewal. During the telephone conference call, the applicant agreed to provide additional information to address the unresolved staff concerns described in RAI 2.1-2 and RAI 2.3.4.2-1a. By letter dated January 10, 2013, the applicant supplemented its response to RAI 2.1-2 and also provided a response to RAI 2.3.4.2-1a. The staff's evaluation of RAI 2.3.4.2-1a is documented in SER Section 2.3.4.2.

In its supplemental response to RAI 2.1-2, the applicant stated that, as discussed in its FSAR, the piping for the main steam supply and main feedwater systems are located in "no break zones," which extend from the anchors in the reactor building wall to outside the torsional restraints in the auxiliary building-turbine building wall. The applicant stated that it did not include the nonsafety-related piping, which is attached to the safety-related piping for the main steam supply and main feedwater systems and located in the turbine building, within the scope of license renewal. The applicant also stated that the basis for not including the nonsafety-related pipe within the scope of license renewal was the result of an analysis of a postulated failure of the nonsafety-related piping beyond the "no break zones," as documented in the FSAR, which concludes that a failure of the nonsafety-related piping beyond the torsional restraints in the "no break zone" will not prevent the connected safety-related components from performing their intended function. The applicant further stated that it has taken an exception to NEI 95-10, Appendix F, and did not include a portion of the nonsafety-related piping attached to the safety-related piping of the main steam supply and main feedwater systems, beyond the torsional restraints in the "no break zone" and located in the turbine building, within the scope of license renewal. The applicant also revised the license renewal boundary drawing for the steam generator blowdown system to identify the nonsafety-related piping, beyond the safety-related to nonsafety-related interface and located within the turbine building, up to and including an anchor, equivalent anchor, or bounding condition, in accordance with guidance contained in NEI 95-10, Appendix F, within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

The staff reviewed the supplemental response to RAI 2.1-2 and the response to RAI 2.3.4.2-1, as documented in SER Section 2.3.4.2, and determined that the applicant had performed an evaluation and provided a basis for the main steam supply and main feedwater systems indicating that: (1) the safety-related to nonsafety-related interface was located in the wall connecting the safety-related auxiliary building and nonsafety-related turbine building and (2) the FSAR documented the results of an analysis that concluded a failure of the nonsafety-related piping attached to safety-related piping and located in the turbine building would not affect the intended function of the attached safety-related pipe. The staff further determined for the steam generator blowdown system that the applicant had included the nonsafety-related pipe attached to safety-related pipe and located within the turbine building up to and including an anchor, equivalent anchor, or bounding condition within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). Therefore, the staff finds the applicant response to RAI 2.1-2, as supplemented by letter dated January 10, 2013, acceptable. The staff's concern described in RAI 2.1-2 is resolved.

The staff determined that additional information would be required to complete its review. By letter dated July 9, 2012, the staff issued RAI 2.1-3 which states, in part:

> The staff determined that the applicant had identified safety-related electrical SSCs, located within the turbine building, that were not included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1).
>
> The staff requests that the applicant describe the process used to identify and evaluate the safety-related electrical SSCs, located within the turbine building, and the basis to not include the SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(1).

In its response letter, dated August 9, 2012, the applicant stated, in part:

> During the scoping process, all components were considered to be safety-related if they had a Y flag in the Q-QUAL field of the CEL. Several electrical components (along with the associated cabling) in the turbine building had Y in the Q-QUAL field.…
>
> From a review of the FSAR and engineering evaluations, it was determined that these components do not have a safety-related function. The components were therefore not included within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(1).…

Based on its review the staff finds the applicant's response to RAI 2.1-3 acceptable because: (1) the applicant had evaluated the electrical components located in the turbine building and identified as Q in the CEL, to determine if the components had a safety-related function, and (2) the applicant had identified 26 electrical components in the turbine building that were flagged as Q in the CEL, reviewed applicable information contained in the FSAR and engineering evaluations, and concluded that the components did not have a safety-related function and, therefore, were not included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). The staff's concern described in RAI 2.1-3 is resolved.

2.1.4.1.3 Conclusion

On the basis of its review of the LRA and the applicant's implementing procedures and reports, reviews of a system on a sampling basis, discussions with the applicant, review of the information provided in the responses to RAIs 2.1-1, 2.1-2, and 2.1-3 the staff concludes that the applicant's methodology for identifying safety-related SSCs, relied upon to remain functional during and following DBEs and including the SSCs within the scope of license renewal, is consistent with the SRP-LR and 10 CFR 54.4(a)(1), and is therefore acceptable.

2.1.4.2 Application of the Scoping Criteria in Title 10, Part 54.4(a)(2) of the Code of Federal Regulations

2.1.4.2.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify SSCs included within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4(a)(2).

LRA Section 2.1.2.2, "10 CFR 54.4(a)(2)–Nonsafety-Related Affecting Safety-Related," states, in part:

> Nonsafety-Related SSCs Performing Safety-Related 10 CFR 54.4(a)(1) Functions. The FSAR 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. Callaway 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 SSCs up to the first seismic anchor or equivalent anchor past the safety/nonsafety interface.
>
> Nonsafety-Related SSCs Not Directly Connected to Safety-Related SSCs. In accordance with NEI 95-10, Appendix F, Callaway applied the preventive option for 10 CFR 54.4(a)(2) scoping. The preventive option is based on scoping nonsafety-related SSCs not directly connected to safety-related SSCs within the scope of license renewal, which could lead to an interaction with safety-related SSCs. Mechanical nonsafety-related interactions with safety-related SSCs include high, moderate, and low energy fluid/steam spatial interaction and potential flooding of safety-related SSCs. Jet impingement, pipe whip, flood barriers, curbing, and pipe supports to prevent falling pipe are structural SSCs and are managed in the structural area.

2.1.4.2.2 Staff Evaluation

RG 1.188, Revision 1, endorses the use of NEI 95-10, Revision 6, which discusses the implementation of the staff's position on 10 CFR 54.4(a)(2) scoping criteria, to include nonsafety-related SSCs that may have the potential to prevent satisfactory accomplishments of safety-related intended functions. This includes nonsafety-related SSCs connected to safety-related SSCs, nonsafety-related SSCs in proximity to safety-related SSCs, and mitigative and preventative options related to nonsafety-related and safety-related SSCs interactions. LRA Section 2.1.2.2 states that the applicant's methodology is consistent with the guidance contained in NEI 95-10, Revision 6, Appendix F.

In addition, the staff's position (as discussed in SRP-LR Section 2.1.3.1.2) is that the applicant should not consider hypothetical failures, but rather should base its 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 in accordance with 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 in accordance with 10 CFR 54.4(a)(2).

Nonsafety-Related SSCs Required to Perform a Function that Supports a Safety-Related SSC. The staff reviewed LRA Section 2.1.2.2 and the applicant's 10 CFR 54.4(a)(2) implementing

procedure that described the method used to identify nonsafety-related SSCs, required to perform a function that supports a safety-related SSC intended function, within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). The staff confirmed that the applicant had reviewed the FSAR, plant drawings, the 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 staff determined that the applicant had not identified any nonsafety-related SSCs that performed a safety function or supported a safety system that would require the nonsafety-related SSCs to be included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

The staff determined that the applicant's methodology for identifying nonsafety-related systems that perform functions that support safety-related intended functions, for inclusion within the scope of license renewal, was in accordance with the guidance of the SRP-LR and the requirements of 10 CFR 54.4(a)(2).

Nonsafety-Related SSCs Directly Connected to Safety-Related SSCs. The staff reviewed LRA Section 2.1.2.2 and the applicant's 10 CFR 54.4(a)(2) implementing procedure that described the method used to identify nonsafety-related SSCs, directly connected to safety-related SSCs, within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). 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 the applicant had used a combination of the following to identify the portion of nonsafety-related piping systems to include within the scope of license renewal:

- seismic anchors
- equivalent anchors
- 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)

The staff determined that additional information would be required to complete its review. By letter dated July 9, 2012, the staff issued RAI 2.1-4, which states, in part:

> The staff determined that LRA Section 2.1.2.2, "10 CFR 54.4(a)(2)–Nonsafety-Related Affecting Safety-Related," states that for nonsafety-related SSCs directly connected to safety-related SSCs, "equivalent anchors as defined in the Current Licensing Basis (CLB)," were not used because equivalent anchors are not defined in the Callaway CLB. However, during a review of the license renewal drawings, the staff noted examples where the drawing notes credited "equivalent anchors as defined in the CLB" as the termination point for attached piping included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).
>
> The staff requests that the applicant discuss the use of equivalent anchors supporting nonsafety-related SSCs, connected to safety-related SSCs, included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

In its response letter, dated August 9, 2012, the applicant stated, in part:

> Credit was taken in license renewal for equivalent anchors as defined in the CLB at the locations where the main steam piping passes through the auxiliary building-turbine building wall.
>
> For this piping, the Callaway FSAR defines the portion of piping extending from the outside of the inboard isolation restraint to the outside of the outboard isolation restraint as a "no break zone." The inboard isolation restraint for a main steam line is the anchor at the containment penetration. The outboard isolation restraint is at the penetration in the auxiliary building-turbine building wall. The FSAR states that the maximum stress in the "no break zone" is acceptable when subjected to the combined loadings of internal pressure, deadweight, and postulated pipe break beyond the "no break zone."
>
> The FSAR further states that isolation restraints protect an essential portion of a piping system from postulated leaks either upstream or downstream of the protected area. These restraints limit pipe motion in all directions.
>
> Thus, the isolation restraints in the auxiliary building-turbine building wall for the main steam piping are equivalent anchors as defined in the CLB.
>
> LRA Section 2.1.2.2 has been revised to delete the statement that equivalent anchors are not defined in the Callaway CLB.

Based on its review the staff finds the applicant's response to RAI 2.1-4 acceptable because: (1) the applicant had provided information indicating that the FSAR did provide a definition of an equivalent anchor and that the applicant had taken credit for the use of an equivalent anchor, as defined in the FSAR, in one application, and (2) the applicant had revised the LRA to remove the statement that an equivalent anchor is not defined in the CLB and had not been used in identifying the boundaries of nonsafety-related pipe within the scope of license renewal. The staff's concern described in RAI 2.1-4 is resolved.

The staff determined that the applicant's methodology for identifying and including nonsafety-related SSCs, directly connected to safety-related SSCs, within the scope of license renewal, was in accordance with the guidance of the SRP-LR and the requirements of 10 CFR 54.4(a)(2).

Nonsafety-Related SSCs with the Potential for Spatial Interaction with Safety-Related SSCs. The staff reviewed LRA Section 2.1.2.2 and the applicant's 10 CFR 54.4(a)(2) implementing procedure that described the method used to identify nonsafety-related SSCs, with the potential for spatial interaction with safety-related SSCs, within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). The staff determined that the applicant had used a spaces approach to identify the portions of nonsafety-related systems with the potential for spatial interaction with safety-related SSCs. The spaces approach focused on the interaction between nonsafety-related and safety-related SSCs that are located in the same space, which was described in the LRA as a structure containing active or passive safety-related SSCs.

The staff determined that the applicant had identified all nonsafety-related SSCs, containing liquid or steam and located in spaces containing safety-related SSCs, and included the nonsafety-related SSCs within the scope of license renewal, unless it had been evaluated by the applicant and determined that the failure of the nonsafety-related SC would not result in the

loss of a 10 CFR 54.4(a)(1) intended function. The staff also determined that, based on plant and industry operating experience, the applicant excluded the nonsafety-related SSCs containing air or gas from the scope of license renewal, with the exception of portions that are attached to safety-related SSCs and required for structural support.

The staff determined that the applicant's methodology for identifying and including nonsafety-related SSCs, with the potential for spatial interaction with safety-related SSCs, within the scope of license renewal, was in accordance with the guidance of the SRP-LR and the requirements of 10 CFR 54.4(a)(2).

2.1.4.2.3 Conclusion

On the basis of its LRA review and the applicant's implementing procedures and reports, selected system reviews and walkdowns, discussions with the applicant, and review of the information provided in the response to RAI 2.1-4, the staff concludes that the applicant's methodology for identifying and including nonsafety-related SSCs, whose failure could prevent satisfactory accomplishment of the intended functions of safety-related SSCs, within the scope of license renewal, is in accordance with the requirements 10 CFR 54.4(a)(2), and, therefore, is acceptable.

2.1.4.3 Application of the Scoping Criteria in Title 10, Part 54.4(a)(3) of the Code of Federal Regulations

2.1.4.3.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify SSCs included within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4(a)(3).

LRA Section 2.1.2.3, "10 CFR 54.4(a)(3)–Regulated Events," states:

> 10 CFR 54.4(a)(3) requires that plant SSCs within the scope of license renewal include all SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63).

LRA Section 2.1.2.3 also states that "SSCs credited in the regulated events have been classified as satisfying criterion 10 CFR 54.4(a)(3) and have been identified as within the scope of license renewal."

2.1.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.1.2.3, which described the method used to identify, and include within the scope of license renewal, those SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations for fire protection (10 CFR 50.48), EQ (10 CFR 50.49), PTS (10 CFR 50.61), ATWS (10 CFR 50.62), and SBO (10 CFR 50.60). As part of this review, during the scoping and screening methodology audit the staff had discussions with the applicant, reviewed implementing procedure and the technical basis documents (topical reports), license renewal drawings, and scoping results reports. The staff determined that the applicant had evaluated the CLB to identify SSCs that perform functions addressed in 10 CFR 54.4(a)(3) and included

these SSCs within the scope of license renewal, as documented in the scoping reports. In addition, the staff determined that the scoping report results referenced the information sources used for determining the SSCs credited for compliance with the events.

Fire Protection. The staff reviewed the applicant's implementing procedure and topical report that described the method used to identify SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(3) (fire protection–10 CFR 50.48). The implementing procedure described a process that considered CLB information, including the FSAR and the fire protection technical basis document. The staff reviewed applicable portions of the LRA, CLB information, and license renewal drawings to verify the appropriate SSCs were included within the scope of license renewal. In addition, the staff reviewed a selected sample of scoping reports for the systems and structures identified in the fire protection topical report. Based on its review of the CLB documents and the sample report review, the staff determined that the applicant's methodology was adequate for identifying and including SSCs credited in performing fire protection functions within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(3).

Environmental Qualification. The staff reviewed the applicant's implementing procedure and topical report that described the method used to identify SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(3) (EQ–10 CFR 50.49). The implementing procedure described a process that considered CLB information, including the FSAR and the EQ technical basis document. The staff reviewed applicable portions of the LRA, CLB information, Callaway EQ program documentation, and license renewal drawings to verify the appropriate SSCs were included within the scope of license renewal. In addition, the staff reviewed a selected sample of scoping reports for the systems and structures identified in the EQ technical basis document. Based on its review of the CLB documents and the sample report review, the staff determined that the applicant's methodology was adequate for identifying and including SSCs credited in performing EQ functions within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(3).

Pressurized Thermal Shock. The staff reviewed the applicant's implementing procedure and topical report that described the method used to identify SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(3) (PTS–10 CFR 50.61). The topical report described the process to review the licensing basis for PTS at Callaway. The only component within the scope of license renewal for PTS is the reactor pressure vessel. The staff reviewed applicable portions of the LRA, CLB information, and license renewal drawings to verify the appropriate SSCs were included within the scope of license renewal. Based on its review of the CLB documents and the topical report, the staff determined that the applicant's methodology was adequate for identifying and including the reactor pressure vessel in performing PTS functions within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(3).

Anticipated Transient Without Scram. The staff reviewed the applicant's implementing procedure and topical report that described the method used to identify SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(3) (ATWS–10 CFR 50.62). The implementing procedure described a process that considered CLB information, including the FSAR and the ATWS technical basis document. The staff reviewed applicable portions of the LRA, CLB information, and license renewal drawings to verify the appropriate SSCs were included within the scope of license renewal. In addition, the staff reviewed a selected sample of scoping reports for the systems and structures identified in the ATWS technical basis document. Based on its review of the CLB documents and the sample report review, the staff

determined that the applicant's methodology was adequate for identifying and including SSCs credited in performing ATWS functions within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(3).

Station Blackout. The staff reviewed the applicant's implementing procedure and topical report that described the method used to identify SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(3) (SBO–10 CFR 50.63). The implementing procedure described a process that considered CLB information, including the FSAR and the SBO technical basis document. The staff reviewed applicable portions of the LRA, CLB information, applicable portions of the FSAR, and commitments and analyses that demonstrate compliance with 10 CFR 50.63 and license renewal drawings to verify the appropriate SSCs were included within the scope of license renewal. In addition, the staff reviewed a selected sample of scoping reports for the systems and structures identified in the SBO technical basis document. Based on its review of the CLB documents and the sample report review, the staff determined that the applicant's methodology was adequate for identifying and including SSCs credited in performing SBO functions within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(3).

2.1.4.3.3 Conclusion

On the basis of its LRA review and the applicant's implementing procedures and reports, reviews of systems on a sampling basis, and discussions with the applicant, the staff concludes that the applicant's methodology for identifying and including SSCs, relied upon to remain functional during regulated events is consistent with the SRP-LR and 10 CFR 54.4(a)(3) and, therefore, is acceptable.

2.1.4.4 Plant-Level Scoping of Systems and Structures

2.1.4.4.1 Summary of Technical Information in the Application

The applicant described the methods used to identify SSCs included within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a) in LRA Section 2.1.3, "Scoping Methodology," which states:

Scoping of SSCs was performed to the criteria of 10 CFR 54.4(a) to identify those SSCs within the scope of the license renewal rule. The following sections describe the methodology used for scoping. Separate discussions of mechanical system scoping methodology, structures scoping methodology, and electrical and instrumentation and control system scoping methodology are provided.

2.1.4.4.2 Staff Evaluation

The staff reviewed the applicant's methodology for identifying SSCs within the scope of license renewal to verify it met the requirements of 10 CFR 54.4. The applicant had developed implementing procedures that described the processes used to identify the systems and structures that are subject to 10 CFR 54.4 review and to determine if the system or structure performed intended functions consistent with the criteria of 10 CFR 54.4(a) and to document the activities in scoping results reports. The process defined the plant in terms of systems and structures and was completed for all systems and structures on site to ensure that the entire plant was assessed.

The staff determined that the applicant had identified the SSCs within the scope of license renewal and documented the results of the scoping process in reports in accordance with the implementing procedures. The reports included 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, and the basis for the classification of the system or structure intended functions. During the audit, the staff reviewed a sampling of the implementing documents and reports and determined 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 LRA review, implementing procedures, and a sampling of system scoping results reviewed during the audit, the staff concludes that the applicant's methodology for identifying systems and structures within the scope of license renewal, and their intended functions, is consistent with the requirements of 10 CFR 54.4 and, therefore, is acceptable.

2.1.4.5 Mechanical Component Scoping

2.1.4.5.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify mechanical SSCs within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a).

LRA Section 2.1.3.1, "Mechanical System Scoping Methodology," states that a "list of mechanical systems was developed and is documented in a topical report. These mechanical systems were evaluated to each of the criteria of 10 CFR 54.4(a)."

LRA Section 2.1.3.1, "Determination of the License Renewal Boundary," states, in part:

> After the system functions were identified, the system boundary was determined and marked–up on P&IDs. The components needed for the system to perform its intended functions were included within the license renewal boundary. The system scoping summaries included in [LRA] Section 2.3, *Scoping and Screening Results: Mechanical Systems* provide a description of the license renewal boundary for each mechanical system in the scope of the Rule.
>
> The process to determine the system license renewal boundary required examination of interfaces with other systems. System interfaces were evaluated to ensure that all components were included in the boundary of one of the interfacing systems.

2.1.4.5.2 Staff Evaluation

The staff evaluated LRA Sections 2.1.3 and 2.1.3.1, implementing procedures, reports, and the CLB source information associated with mechanical scoping. The staff determined that the CLB source information and the implementing procedure guidance used by the applicant were acceptable to identify mechanical SSCs 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 if the applicant had appropriately applied the scoping methodology outlined in the LRA and implementing procedures and if the scoping results were consistent with CLB requirements. The staff determined that the applicant's procedure was

consistent with the description provided in LRA Sections 2.1.3 and 2.1.3.1 and the guidance contained in SRP-LR Section 2.1 and was adequately implemented.

On a sampling basis, the staff reviewed the applicant's scoping reports for the essential service water system and the process used to identify mechanical 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 system's identified intended functions and the process used to identify 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 verified the results in accordance with the implementing procedures. The staff confirmed that the applicant's license renewal personnel verifying the results 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 and components 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 and components 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 information contained in the LRA, scoping implementing procedures, and a sampling review of scoping results, the staff concludes that the applicant's methodology for identifying mechanical SSCs within the scope of license renewal is in accordance with the requirements of 10 CFR 54.4 and, therefore, is acceptable.

2.1.4.6 Structural Component Scoping

2.1.4.6.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify SSCs included within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a). LRA Section 2.1.3.2, "Structure Scoping Methodology," states, in part that

> A list of structures was developed that included buildings, tank foundations, and other miscellaneous structures. These structures are listed in [LRA] Table 2.2-1, *Callaway Plant Scoping Results*. The FSAR was relied upon to identify the safety classifications of structures and structural components.

The scoping methodology used for structures was similar to the mechanical system-level scoping described in [LRA] Section 2.1.3.1, "Mechanical System Scoping Methodology." 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.

2.1.4.5.2 Staff Evaluation

The staff evaluated LRA Section 2.1.3.2, implementing procedures, reports, and the CLB source information associated with structural scoping. The staff determined that the CLB source

information and the implementing procedure guidance used by the applicant were acceptable to identify structural SSCs 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 if the applicant had appropriately applied the scoping methodology outlined in the LRA and implementing procedures and if the scoping results were consistent with CLB requirements. The staff determined that the applicant's procedure was consistent with the description provided in the LRA Section 2.1.3.2 and the guidance contained in SRP-LR Section 2.1, and was adequately implemented.

On a sampling basis, the staff reviewed the applicant's scoping reports for the turbine building, essential service water pump house, EDG building, and the UHS basin, and the process used to identify structural systems and 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 structures identified intended functions and the process used to identify structural component types. Additionally, the staff determined that the applicant had verified the results in accordance with the implementing procedures. The staff confirmed that the applicant's license renewal personnel verifying the results 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 SCs 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 and components 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 contained in the LRA, scoping implementing procedures, and a sampling review of scoping results, the staff concludes that the applicant's methodology for identifying structural SSCs within the scope of license renewal is in accordance with the requirements of 10 CFR 54.4 and, therefore, is acceptable.

2.1.4.7 Electrical Component Scoping

2.1.4.7.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify SSCs included within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a).

LRA Section 2.1.3.3, "Electrical and Instrumentation and Control System Scoping Methodology," states, in part:

> At the system level, the scoping methodology utilized for electrical and instrumentation and control systems was similar to the mechanical system-level scoping described in [LRA] Section 2.1.3.1, *Mechanical System Scoping Methodology*. The FSAR descriptions, plant 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 results of the system level scoping along with a list of references

supporting the evaluation of each electrical and instrumentation and control system were documented.

LRA Section 2.1.3.3 further states that "[e]lectrical and instrumentation and control 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 reviewed LRA Section 2.1.3.3, implementing procedures, reports, and the CLB source information associated with electrical scoping. The staff determined that the CLB source information and implementing procedures' guidance used by the applicant was acceptable to identify electrical SSCs 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 if the applicant had appropriately applied the scoping methodology outlined in the LRA and implementing procedures and if 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 2.1.3.3 and the guidance contained in SRP-LR Section 2.1, and was adequately implemented.

The staff noted that after the scoping of electrical and instrumentation and controls (I&C) components was performed, the in-scope electrical components were categorized into electrical commodity groups. Commodity groups include electrical and I&C components with common characteristics. Component level intended functions of the component types were identified. The electrical commodities included insulated cable and connections, connectors, terminal blocks, high-voltage insulators, transmission conductor, transmission connections, metal enclosed bus, and switchyard bus and connections.

As part of this review, the staff discussed the methodology with the applicant, reviewed the implementing procedures developed to support the review, and reviewed the scoping results for a sample of SSCs that were identified within the scope of license renewal. The staff determined that the applicant's scoping included appropriate electrical and I&C components as well as 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 scoping results, the staff concludes that the applicant's methodology for identifying electrical SSCs within the scope of license renewal is in accordance with the requirements of 10 CFR 54.4 and, therefore, is acceptable.

2.1.4.8 Conclusion for Scoping Methodology

On the basis of its review of information contained in the LRA, scoping 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: (1) that are safety-related; (2) whose failure could affect safety-related intended functions; and (3) that are necessary to demonstrate compliance with the NRC's regulations for fire protection, EQ, PTS, ATWS, and SBO. The staff concluded that the applicant's

methodology is consistent with the requirements of 10 CFR 54.4(a), and, therefore, is acceptable.

2.1.5 Screening Methodology

2.1.5.1 General Screening Methodology

2.1.5.1.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify SCs included within the scope of license renewal that are subject to AMR in accordance with the requirements of 10 CFR 54.21. LRA Section 2.1.4, "Screening Methodology," states, in part:

> 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, Appendix B, "Typical Structure, Component and Commodity Groupings and Active/Passive Determinations for the Integrated Plant Assessment," provides industry guidance for screening SCs. The guidance provided in NEI 95-10, Appendix B, has been incorporated into the Callaway license renewal screening process. The screening methodology applied for each category of system and for structures is described in the following paragraphs.

2.1.5.1.2 Staff Evaluation

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

The staff reviewed the methodology used by the applicant to identify the mechanical, structural, and electrical SSCs 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). 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 on a sampling basis the screening results reports for the essential service water system 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, structural, and electrical SCs is discussed in safety evaluation report (SER) Sections 2.1.5.2, 2.1.5.3, and 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 within the scope of license renewal that are subject to an AMR. The staff concludes that the applicant's process for determining the SCs that are subject to an AMR is consistent with the requirements of 10 CFR 54.21 and, therefore, is acceptable.

2.1.5.2 Mechanical Component Screening

2.1.5.2.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify mechanical SCs included within the scope of license renewal that are subject to an AMR in accordance with the requirements of 10 CFR 54.21. LRA Section 2.1.4.1, "Mechanical System Component Screening Methodology," states, in part:

> 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. The results of the component screening were documented.

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 applicant's methodology used for mechanical component screening as described in LRA Section 2.1.4.1, implementing procedures, basis documents, and the mechanical scoping and screening reports. The staff determined 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 mechanical SCs subject to an AMR.

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

The staff performed a sample review to determine if the screening methodology outlined in the LRA and implementing procedures was adequately implemented. During the scoping and screening methodology audit, the staff reviewed the essential service water system screening report and basis documents, had discussions with the applicant, and verified proper implementation of the screening process.

2.1.5.2.3 Conclusion

On the basis of its review of information contained in the LRA, implementing procedures, and the sampled mechanical screening results, the staff concludes that the applicant's methodology for identification of mechanical SCs within the scope of license renewal and subject to an AMR is in accordance with the requirements of 10 CFR 54.21(a)(1) and, therefore, is acceptable.

2.1.5.3 Structural Component Screening

2.1.5.3.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify structural SCs included within the scope of license renewal that are subject to an AMR in accordance with the requirements of 10 CFR 54.21. LRA Section 2.1.4.2, "Structural Component Screening Methodology," states, in part:

> During the structural screening process, the intended function(s) of passive structural components were documented. In the structure screening process, an evaluation was made to determine whether in-scope structural components were subject to replacement based on a qualified life or specified time period. If an in-scope structural component was determined to be subject to replacement based on a qualified life or specified time period, the component was identified as short-lived and was excluded from an AMR. In such a case, the basis for determining that the structural component was short-lived was documented.

2.1.5.3.2 Staff Evaluation

The staff reviewed the applicant's methodology used for structural component screening as described in LRA Section 2.1.4.2, implementing procedures, basis documents, and the structural scoping and screening reports. The staff determined 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 structural SCs subject to an AMR.

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

The staff performed a sample review to determine if the screening methodology outlined in the LRA and implementing procedures was adequately implemented. During the scoping and screening methodology audit, the staff reviewed the turbine building screening report and basis documents, had discussions with the applicant, and verified proper implementation of the screening process.

2.1.5.3.3 Conclusion

On the basis of its review of information contained in the LRA, implementing procedures, and the sampled structural screening results, the staff concludes that the applicant's methodology to identify structural SCs within the scope of license renewal and subject to an AMR is in accordance with the requirements of 10 CFR 54.21(a)(1) and, therefore, is acceptable.

2.1.5.4 Electrical Component Screening

2.1.5.4.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify electrical SCs included within the scope of license renewal that are subject to an AMR in accordance with the requirements of 10 CFR 54.21. LRA Section 2.1.4.3, "Electrical and Instrumentation and Control Component Screening Methodology," states, in part:

> 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 instrumentation and control components used the spaces approach which is consistent with the guidance in NEI 95-10. The spaces approach to AMR is based on areas where bounding environmental conditions are identified. The bounding environmental conditions are applied during AMR to evaluate the aging effects on passive electrical component types that are located within the bounding area. Use of the spaces approach for AMR of electrical component types eliminates the need to associate electrical and instrumentation and control components with specific systems that are within the scope of license renewal. The passive long-lived electrical and instrumentation and control components that perform an intended function without moving parts or without change in configuration or properties were grouped into component types such as insulated cable and connections, connectors, terminal blocks, high-voltage insulators, transmission conductor, transmission connections, metal enclosed bus, and switchyard bus and connections. Component-level intended function(s) were determined for each in-scope passive electrical component group and documented. The passive in-scope electrical component types were documented as subject to an AMR.

2.1.5.4.2 Staff Evaluation

The staff reviewed the applicant's methodology used for electrical component screening as described in LRA Section 2.1.4.3, implementing procedures, basis documents, and the electrical scoping and screening reports. The staff confirmed that the applicant had 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 SSCs subject to an AMR.

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

The staff performed a sample review to determine if the screening methodology outlined in the LRA and implementing procedures was adequately implemented. During the scoping and screening methodology audit, the staff reviewed electrical screening reports and basis documents, had discussions with the applicant, and verified proper implementation of the screening process.

2.1.5.4.3 Conclusion

On the basis of its review of information contained in the LRA, implementing procedures, and the sampled structural screening results, the staff concludes that the applicant's methodology to identify electrical and I&C SCs within the scope of license renewal and subject to an AMR is in accordance with the requirements of 10 CFR 54.21(a)(1) and, therefore, is acceptable.

2.1.5.5 Conclusion for Screening Methodology

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

2.1.6 Summary of Evaluation Findings

On the basis of its review of the information presented in LRA Section 2.1, the supporting information in the scoping and screening implementing procedures and reports, the information presented during the scoping and screening methodology audit, discussions with the applicant, sample system reviews, and the applicant's responses to RAIs 2.1-1, 2.1-2, 2.1-3, and 2.1-4, the staff confirms that the applicant's scoping and screening methodology is consistent with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1). The staff also concludes that the applicant's description and justification of its scoping and screening methodology are adequate to meet the requirements of 10 CFR 54.21(a)(1). From this review, the staff concludes that the applicant's methodology for identifying systems and structures within the scope of license renewal and SCs requiring an AMR is acceptable.

2.2 Plant-Level Scoping Results

2.2.1 Introduction

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

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

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

2.2.2 Summary of Technical Information in the Application

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

2.2.3 Staff Evaluation

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

The staff determined if 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 verify if the systems and structures have any intended functions requiring their inclusion within the scope of license renewal. The staff's review of the applicant's implementation was conducted in accordance with the guidance in SRP-LR Section 2.2, "Plant-Level Scoping Results."

The staff noted that LRA Table 2.2-1 provides the results of applying the license renewal scoping criteria to the systems, structures, and commodities and the license renewal scoping criteria was described in LRA Section 2.1. The staff reviewed FSAR Section 18.1.17, "Plant Safety Parameter Display System," but could not locate the plant safety parameter display system in LRA Table 2.2-1.

By letter dated June 11, 2012, the staff issued RAI 2.2-1 requesting the applicant to justify the exclusion of the plant safety parameter display system from LRA Table 2.2-1.

In its response letter, dated July 2, 2012, the applicant stated the plant safety parameter display system is included in the plant computer system. The applicant also stated that the plant computer system is listed in LRA Table 2.2-1 and has been excluded from the scope of license renewal since it does not perform any of the intended functions that satisfy the criteria in 10 CFR 54.4(a)(1), (a)(2), or (a)(3).

Based on its review, the staff finds the applicant's response to RAI 2.2-1 acceptable because the applicant explained that the plant safety parameter display system is included in the plant computer system in LRA Table 2.2-1. The staff finds the applicant's exclusion of the plant computer from scope of license renewal acceptable since it does not have any license renewal intended functions. Therefore, the staff's concern described in RAI 2.2-1 is resolved.

2.2.4 Conclusion

The staff reviewed LRA Section 2.2, the RAI response, and the FSAR supporting information to determine if 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:

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

In accordance with the requirements of 10 CFR 54.21(a)(1), the applicant must list passive, long-lived SCs within the scope of license renewal and subject to an AMR. To verify the applicant properly implemented its methodology, the staff's review focused on the implementation results. This focus allowed the staff to verify 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 in the guidance in SRP-LR Section 2.3 and took into account the system function(s) described in the FSAR. The objective was to determine if the applicant, in accordance with 10 CFR 54.4, has identified components and supporting structures for mechanical systems that meet the license renewal scoping criteria. Similarly, the staff evaluated the applicant's screening results to verify that all passive, long-lived components are subject to an AMR as required by 10 CFR 54.21(a)(1).

In its scoping evaluation, the staff reviewed the LRA, applicable sections of the FSAR, 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 verified the applicant properly screened out only: (1) SCs that have functions performed with moving parts or a change in configuration or properties, or (2) SCs that are subject to replacement after a qualified life or specified time period, as described in 10 CFR 54.21(a)(1). For SCs not meeting either of these criteria, the staff identified the remaining SCs subject to an AMR, as required by 10 CFR 54.21(a)(1). The staff requested additional information to resolve any omissions or discrepancies identified.

2.3.1 Reactor Vessel, Internals, and Reactor Coolant System

LRA Section 2.3.1 identifies the reactor vessel, internals, and RCS SCs subject to an AMR for license renewal.

The applicant described the supporting SCs of the reactor vessel, internals, and RCS in the following LRA sections:

- LRA Section 2.3.1.1, “Reactor Vessel and Internals”
- LRA Section 2.3.1.2, “Reactor Coolant System”
- LRA Section 2.3.1.3, “Pressurizer”
- LRA Section 2.3.1.4, “Steam Generators”
- LRA 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 purpose of the reactor vessel is to function as an RCS pressure boundary which acts as a barrier to prevent the release of radioactivity generated within the reactor. The reactor vessel is a cylindrical vessel with a welded hemispherical bottom head and a removable, bolted, flanged hemispherical upper head. The vessel contains the core, core supporting structures, control rods, and other parts directly associated with the core. The top head also has penetrations for the control rod drive mechanisms (CRDMs) and the head vent pipe. The O-ring leak monitoring tube penetrations are in the vessel flange. Reactor coolant flows through the vessel inlet and outlet nozzles located in a horizontal plane just below the reactor vessel flange, but above the top of the core. The vessel is supported by pads on the bottom of four of the eight nozzles. The bottom head of the vessel contains penetration nozzles for connection and entry of the nuclear incore instrumentation.

The reactor internals consist of the lower core support structure, the upper core support structure, and the incore instrumentation support structure. The reactor internals provide various functions, including supporting the core, maintaining fuel alignment, limiting fuel assembly movement, maintaining alignment between fuel assemblies and CRDMs, directing coolant flow past the fuel elements, directing coolant flow to the pressure vessel head, and providing gamma and neutron shielding and guiding incore instrumentation.

The lower core support structure includes the baffle and former plates, core barrel assembly, neutron shield panel, lower core plates, core support forging, support columns, secondary core support, energy absorbers, tie plates, and man way cover.

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

- to serve as a pressure boundary for containing reactor coolant
- to provide a barrier against the release of radioactivity
- to support and contain the reactor core and core support structures
- to provide support, orientation, guidance, and protection of the reactor controls and instrumentation
- to direct the main flow of coolant through the core

- to provide for secondary flows for cooling of the reactor vessel and internals
- to maintain fuel alignment and limit fuel assembly movement
- to provide gamma and neutron shielding
- to support fire protection (10 CFR 50.48), PTS (10 CFR 50.61), and SBO (10 CFR 50.63) requirements

LRA Table 2.3.1-1 identifies the reactor vessel and internals component types within the scope of license renewal and subject to 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. On the basis of its review, the staff 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 SER Section 2.3 and on a review of the LRA and FSAR, the staff concludes that the applicant appropriately identified the reactor vessel and internals components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concluded that the applicant adequately identified the reactor vessel and internals components subject to an AMR, as required by 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 purpose of the RCS is to transfer the heat generated in the reactor core to the steam generators, where steam is produced to drive the turbine generator. The RCS provides a pressure boundary barrier for containing the coolant under all anticipated temperature and pressure conditions and for limiting the release of radioactivity. The RCS consists of four similar heat transfer loops connected in parallel to the reactor vessel. Each loop contains an identical reactor coolant pump (RCP), a steam generator, and interconnecting piping to various auxiliary or safety systems. The RCS also includes a pressurizer, interconnecting piping, pressurizer safety and relief valves, pressurizer relief tank, and instrumentation that provide operational pressure control. Borated pressurized water is circulated in the system to act as a neutron moderator and reflector and as a neutron absorber for chemical shim control.

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

- to serve as a pressure boundary and limit the release of fission products
- to provide RCS pressure control and limit pressure transients
- to provide the borated water used as the core neutron moderator and reflector, and for chemical shim control
- to provide a containment isolation function

- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support fire protection (10 CFR 50.48), EQ (10 CFR 50.49), and SBO (10 CFR 50.63) requirements

LRA Table 2.3.1-2 identifies the RCS component types within the scope of license renewal and subject to 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. On the basis of its review, the staff 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 SER Section 2.3 and on a review of the LRA and FSAR, the staff concludes that the applicant appropriately identified the RCS components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the RCS components subject to an AMR, as required by 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 purpose of the pressurizer is to provide a point within the RCS to maintain liquid and vapor at equilibrium temperature and pressure under saturated conditions for pressure control.

The pressurizer is a vertical, cylindrical vessel with hemispherical top and bottom heads. Installed in the bottom head are a surge line nozzle and removable electric heaters. A thermal sleeve is also installed to minimize stresses in the surge line nozzle. Located in the top head of the vessel are the spray nozzle and the relief and safety valve connections. Automatically controlled air-operated valves modulate the spray flow.

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

- to serve as a pressure boundary
- to provide RCS pressure control and limit pressure transients
- to support fire protection (10 CFR 50.48) and SBO (10 CFR 50.63) requirements

LRA Table 2.3.1-3 identifies the pressurizer component types within the scope of license renewal and subject to 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. On the basis of its review, the staff 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 SER Section 2.3 and on a review of the LRA and FSAR, the staff concludes that the applicant appropriately identified the pressurizer components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the pressurizer components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.1.4 Steam Generators

2.3.1.4.1 Summary of Technical Information in the Application

LRA Section 2.3.1.4 states that the purpose of the steam generators is to provide heat removal from the RCS through the generation of steam and also to act as an assured source of steam for the steam-driven auxiliary feedwater pump. The steam generators system consists of the primary and secondary pressure boundaries of the steam generators, including all pieces and parts within the pressure boundary and all penetrations out to the safe ends of the penetration nozzles.

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

- to serve as a pressure boundary and limit the release of fission products
- to provide RCS heat removal through steam generation
- to provide for inventory and pressure control
- to provide assured source of steam for turbine-driven auxiliary feedwater pump
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support fire protection (10 CFR 50.48) and SBO (10 CFR 50.63) requirements

LRA Table 2.3.1-4 identifies the steam generators component types within the scope of license renewal and subject to 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. On the basis of its review, the staff 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 SER Section 2.3 and on a review of the LRA and FSAR, the staff concludes that the applicant appropriately identified the steam generators components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the steam generators components subject to an AMR, as required by 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 purpose of the reactor core is to provide a heat source for the steam generators to support the generation of steam.

The reactor core consists of 193 fuel assemblies each containing of 264 fuel rods, 24 rod cluster control assembly (RCCA) guide tubes, and an incore instrumentation thimble. Each fuel rod is constructed of zirconium alloy tubing containing uranium dioxide fuel pellets. Spacer grids and top and bottom nozzles hold each rod in place. Guide thimbles are used as core locations for RCCAs, neutron source assemblies, and burnable absorber rods.

The bottom nozzle serves as a structural element of the fuel assembly and directs the coolant flow to the assembly. The top nozzle assembly serves a structural element of the fuel assembly and also provides a partial protective housing for the RCCA or other components. RCCA consists of a group of individual absorber rods fastened to a common hub or spider assembly.

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

- to meet heat transfer performance requirements in all modes
- to serve as a fission product barrier
- to provide reactivity control
- to support fire protection (10 CFR 50.48) requirements

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

2.3.1.5.2 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. On the basis of its review, the staff 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 SER Section 2.3 and on a review of the LRA and the FSAR, the staff concludes that the applicant appropriately identified the reactor core components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the reactor core components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2 Engineered Safety Features

LRA Section 2.3.2 identifies the ESF SCs subject to an AMR for license renewal.

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

- LRA Section 2.3.2.1, “Containment Spray System”
- LRA Section 2.3.2.2, “Containment Integrated Leak Rate Testing System”
- LRA Section 2.3.2.3, “Containment Hydrogen Control System”

- LRA Section 2.3.2.4, “Containment Purge System”
- LRA Section 2.3.2.5, “High-Pressure Coolant Injection System”
- LRA Section 2.3.2.6, “Residual Heat Removal System”

2.3.2.1 Containment Spray System

2.3.2.1 Summary of Technical Information in the Application

LRA Section 2.3.2.1 states that the purpose of the containment spray system is to remove heat from the containment following a loss-of-coolant accident (LOCA) or main steam line break to reduce the containment ambient temperature and pressure. The containment spray system also uses trisodium phosphate for pH control to promote absorption of airborne iodine from the containment atmosphere, should this fission product be released in an accident.

The containment spray system consists of pumps, spray ring headers and nozzles, containment spray system additive eductors, trisodium phosphate baskets, and the associated piping and valves.

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

- to provide pH control to limit airborne iodine
- to maintain containment integrity
- to provide sump filtering
- to provide for containment pressure reduction
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support fire protection (10 CFR 50.48) and EQ (10 CFR 50.49) requirements

LRA Table 2.3.2-1 identifies the containment spray system component types within the scope of license renewal and subject to an AMR.

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. On the basis of its review, the staff 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 SER Section 2.3 and on a review of the LRA and the FSAR, the staff concludes that the applicant appropriately identified the containment spray system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the containment spray system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.2 Containment Integrated Leak Rate Testing System

2.3.2.2.1 Summary of Technical Information in the Application

LRA Section 2.3.2.2 states that the purpose of the containment integrated leak rate testing system is to provide a way to periodically test containment leakage. The containment integrated leak rate testing system achieves this by pressurizing the containment building and monitoring leakage to the atmosphere.

The intended functions of the containment integrated leak rate testing system within the scope of license renewal include the following:

- to provide containment isolation during normal plant operation
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support EQ (10 CFR 50.49) requirements

LRA Table 2.3.2-2 identifies the containment integrated leak rate testing system component types within the scope of license renewal and subject to an AMR.

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. On the basis of its review, the staff 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 SER Section 2.3 and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the containment integrated leak rate testing system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the containment integrated leak rate testing system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.3 Containment Hydrogen Control System

2.3.2.3.1 Summary of Technical Information in the Application

LRA Section 2.3.2.3 states that the purpose of the containment hydrogen control system is to control combustible gas concentrations in the containment following a LOCA. The containment hydrogen control system consists of the electric hydrogen recombiners and the hydrogen monitoring, hydrogen mixing, and backup hydrogen purge subsystems. The containment hydrogen control system monitoring is performed by hydrogen analyzers and associated sample lines with their containment isolation valves. The containment hydrogen control system contains a penetration through which the containment atmosphere is purged and filtered. The system uses the fuel/auxiliary building emergency exhaust system and mixing fans to perform its functions.

The intended functions of the containment hydrogen control system within the scope of license renewal include the following:

- to provide containment isolation
- to provide mixing of the containment atmosphere after a LOCA
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support EQ (10 CFR 50.49) requirements

LRA Table 2.3.2-3 identifies the containment hydrogen control system component types within the scope of license renewal and subject to an AMR.

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. On the basis of its review, the staff 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 SER Section 2.3 and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the containment hydrogen control system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the containment hydrogen control system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.4 Containment Purge System

2.3.2.4.1 Summary of Technical Information in the Application

LRA Section 2.3.2.4 states that the purpose of the containment purge system is to reduce the concentration of noble gases within containment before and during personnel access to the containment or to equalize containment internal pressure with the external pressure. The containment purge system also supplies outside air into the containment for ventilation and cooling or heating needed for prolonged containment access during a reactor outage. The containment purge system consists of the containment minipurge and containment shutdown purge systems. The principal components of the containment purge system include the heating, ventilation, and air-conditioning (HVAC) intake, common unit vent, non-essential filtering unit, supply fans, exhaust fans, containment isolation valves, radiation monitors, and ventilation ducts.

The intended functions of the containment purge system within the scope of license renewal include the following:

- to provide containment isolation valves to limit the escape of fission products from the containment following a DBE
- to provide radiation monitoring and radiation level input to the ESF actuation signal
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support EQ (10 CFR 50.49) requirements

LRA Table 2.3.2-4 identifies the containment purge system component types within the scope of license renewal and subject to an AMR.

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. On the basis of its review, the staff 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 SER Section 2.3 and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the containment purge system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the containment purge system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.2.5 High-Pressure Coolant Injection System

2.3.2.5.1 Summary of Technical Information in the Application

LRA Section 2.3.2.5 states that the purpose of the high-pressure coolant injection (HPCI) system is to remove stored and decay heat from the reactor core and provide shutdown capability during accident conditions. Reactor core cooling is accomplished in two phases. The HPCI system is part of the emergency core cooling (ECC) system. The HPCI takes suction from either the refueling water storage tank (RWST) or residual heat removal (RHR) pump discharge and delivers the borated water to either the RCS cold legs or RCS hot legs. Also included in this section are other parts of the ECC system, the accumulator safety injection (ASI) system, and the borated refuel water storage (BRWS) system. The purpose of the ASI system is to deliver borated water to the RCS coldlegs during the post-LOCA injection phase. The purpose of the BRWS system is to store borated water so that it is available to the refueling pool during refueling, the chemical and volume control (CVC) system during abnormal operating conditions, and the containment spray and ECC systems during accident conditions.

The HPCI system consists of two safety injection pumps, flow orifices, associated piping, valves, and instrumentation. The ASI system consists of four accumulator tanks and the associated piping, valves, and instrumentation. The BWRS system consists of an outdoor storage tank and connections for delivery to and receipt from the fuel pool cooling and cleanup system, the CVC system, the containment spray system, and the ECC system.

The intended functions of the HPCI system within the scope of license renewal include the following:

- to provide heat removal from the reactor core
- to provide reactivity and inventory control during accident conditions
- to maintain the integrity of the RCPB
- to ensure that containment integrity is maintained
- to ensure borated water is available

- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support fire protection (10 CFR 50.48) and EQ (10 CFR 50.49) requirements

LRA Table 2.3.2-5 identifies the HPCI system component types within the scope of license renewal and subject to an AMR.

2.3.2.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.5 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. On the basis of its review, the staff did not identify the need for any additional information.

2.3.2.5.3 Conclusion

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

2.3.2.6 Residual Heat Removal System

2.3.2.6.1 Summary of Technical Information in the Application

LRA Section 2.3.2.6 states that the purpose of the RHR system is to transfer heat from the RCS in normal shutdown and post accident conditions. The RHR system also supports the ECC system during a LOCA injection and recirculation phase. In addition, the RHR system is used to transfer refueling water between the RWST and the refueling cavity.

The RHR system consists of two heat exchangers, two pumps, and associated piping, valves, and instrumentation.

The intended functions of RHR system within the scope of license renewal include the following:

- to form a part of the RCS pressure boundary
- to provide protection against over-pressurization and rupture of ECC system low pressure piping that could result in a LOCA
- to provide borated water for RCS makeup in LOCA conditions
- to remove decay heat in post-accident and normal shutdown conditions
- to ensure that containment integrity is maintained in single failure scenarios
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support fire protection (10 CFR 50.48) and EQ (10 CFR 50.49) requirements

LRA Table 2.3.2-6 identifies the RHR system component types within the scope of license renewal and subject to an AMR.

2.3.2.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.6 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. On the basis of its review, the staff did not identify the need for any additional information.

2.3.2.6.3 Conclusion

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

2.3.3 Auxiliary Systems

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

- LRA Section 2.3.3.1, “Fuel Storage and Handling System”
- LRA Section 2.3.3.2, “Fuel Pool Cooling and Cleanup System”
- LRA Section 2.3.3.3, “Cranes, Hoists, and Elevators”
- LRA Section 2.3.3.4, “Essential Service Water System”
- LRA Section 2.3.3.5, “Service Water System”
- LRA Section 2.3.3.6, “Reactor Makeup Water System”
- LRA Section 2.3.3.7, “Component Cooling Water System”
- LRA Section 2.3.3.8, “Compressed Air System”
- LRA Section 2.3.3.9, “Nuclear Sampling System”
- LRA Section 2.3.3.10, “Chemical and Volume Control System”
- LRA Section 2.3.3.11, “Control Building HVAC System”
- LRA Section 2.3.3.12, “Essential Service Water Pumphouse HVAC System”
- LRA Section 2.3.3.13, “Auxiliary Building HVAC System”
- LRA Section 2.3.3.14, “Fuel Building HVAC System”
- LRA Section 2.3.3.15, “Miscellaneous Buildings HVAC System”
- LRA Section 2.3.3.16, “Diesel Generator Building HVAC System”
- LRA Section 2.3.3.17, “Radwaste Building HVAC System”
- LRA Section 2.3.3.18, “Turbine Building HVAC System”
- LRA Section 2.3.3.19, “Containment Cooling System”
- LRA Section 2.3.3.20, “Fire Protection System”
- LRA Section 2.3.3.21, “Emergency Diesel Engine Fuel Oil Storage and Transfer System”
- LRA Section 2.3.3.22, “Standby Diesel Generator Engine System”
- LRA Section 2.3.3.23, “EOF and TSC Diesels, Security Building System”
- LRA Section 2.3.3.24, “Liquid Radwaste System”
- LRA Section 2.3.3.25, “Decontamination System”
- LRA Section 2.3.3.26, “Oily Waste System”
- LRA Section 2.3.3.27, “Floor and Equipment Drainage System”
- LRA Section 2.3.3.28, “Miscellaneous Systems In Scope ONLY for Criterion 10 CFR 54.4(a)(2)”
- LRA Section 2.3.3.29, “Circulating Water System”

2.3.3.1 Fuel Storage and Handling System

2.3.3.1.1 Summary of Technical Information in the Application

LRA Section 2.3.3.1 states that the purpose of the fuel storage and handling system is to provide onsite storage of new and spent fuel assemblies, provide manipulation of fuel assemblies and rod control clusters, and provide for the servicing of the reactor vessel closure head and internals. The system is designed to minimize the possibility of mishandling or improper operation that could cause fuel assembly damage or potential fission product release. The fuel storage and handling system consists of fuel handling and storage equipment, including cranes, elevators, fuel storage racks, lift rigs, and transfer systems. Fuel cranes and fuel elevators are evaluated in this system.

The intended functions of the fuel storage and handling system within the scope of license renewal include: (1) providing onsite storage and maintain a subcritical arrangement of new and spent fuel assemblies under normal and postulated DBEs; and (2) providing nonsafety-related handling systems to carry heavy loads over safety-related components, or over irradiated fuel in the reactor vessel or spent fuel pool.

LRA Table 2.3.3-1 identifies the fuel storage and handling system component types within the scope of license renewal and 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. On the basis of its review, the staff 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 SER Section 2.3 and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the fuel storage and handling system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system mechanical components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.2 Fuel Pool Cooling and Cleanup System

2.3.3.2.1 Summary of Technical Information in the Application

LRA Section 2.3.3.2 states that the purpose of the fuel pool cooling and cleanup system is to remove decay heat and impurities from the refueling pool water and maintain the spent fuel pool water temperature below prescribed limits. The fuel pool cooling and cleanup system consists of the fuel pool cooling, fuel pool cleanup, and fuel pool surface skimmer systems. Some of the main components of the fuel pool cooling and cleanup system are two 100 percent capacity cooling trains; pumps; shell and U-tube heat exchangers; filters; a mixed bed demineralizer; and associated strainers, piping and valves.

The intended functions of the fuel pool cooling and cleanup system within the scope of license renewal include the following:

- to provide water inventory over the spent fuel assemblies to mitigate the radiological consequences following a design-basis accident
- to maintain fuel storage pool water temperature below prescribed limits
- to provide containment integrity
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)

LRA Table 2.3.3-2 identifies the fuel pool cooling and cleanup system component types within the scope of license renewal and 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. On the basis of its review, the staff 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 SER Section 2.3 and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the fuel pool cooling and cleanup system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.3 Cranes, Hoists, and Elevators

2.3.3.3.1 Summary of Technical Information in the Application

LRA Section 2.3.3.3 states that the purpose of the cranes, hoists, and elevators system is to provide lifting in Category I structures and various nonsafety-related buildings. The cranes, hoists, and elevators system contains nonsafety-related components that perform no safety-related functions. The cranes, hoists, and elevators system consists of cranes, doors, elevators, hoists, and trolleys.

The intended functions of the cranes, hoists, and elevators system within the scope of license renewal are to carry heavy loads over safety-related components required for plant shutdown or decay heat removal and to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2).

LRA Table 2.3.3-3 identifies the cranes, hoists, and elevators system component types within the scope of license renewal and subject to an AMR.

2.3.3.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.3 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. On the basis of its review, the staff did not identify the need for any additional information.

2.3.3.3.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3, and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the cranes, hoists, and elevators system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.4 Essential Service Water System

2.3.3.4.1 Summary of Technical Information in the Application

LRA Section 2.3.3.4 states that the purpose of the essential service water (ESW) system is to provide cooling water to those components that require cooling for safe shutdown of the reactor and conveys the heat to the UHS cooling tower. The ESW system also provides: (1) cooling water to the spent fuel pool cooling pump room coolers, (2) cooling water to nonsafety-related air compressors and associated after-coolers, and (3) emergency makeup to the spent fuel pool and component cooling water (CCW) systems. It also acts as the backup water supply to the auxiliary feedwater system if the condensate storage tank water is unavailable. Some of the components that the ESW system cools are the following:

- the CCW heat exchangers
- containment air coolers
- diesel generator coolers
- safety injection pump room coolers
- RHR pump room coolers
- containment spray pump room coolers
- centrifugal charging pump room coolers
- CCW pump room coolers
- auxiliary feedwater pump room coolers
- control room air conditioning condensers
- Class 1E switchgear air-conditioning condensers
- penetration room coolers.

The intended functions of the ESW system within the scope of license renewal include the following:

- to support the functions of containment isolation, decay heat removal, and inventory and pressure control
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support fire protection (10 CFR 50.49) and EQ (10 CFR 50.49) requirements

LRA Table 2.3.3-4 identifies the ESW system component types within the scope of license renewal and subject to an AMR.

2.3.3.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.4 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. On the basis of its review, the staff did not identify the need for any additional information.

2.3.3.4.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant has appropriately identified the ESW system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.5 Service Water System

2.3.3.5.1 Summary of Technical Information in the Application

LRA Section 2.3.3.5 states that the purpose of the service water system is to provide cooling water to the non-essential components that the ESW system serves during normal plant operation and shutdown. The service water system also supplies fire water to those stations within the ESW pumphouse. The service water system takes water from the cooling tower basin and discharges the heated return water into the circulating water system. The service water system consists of pumps, piping, valves, strainers, heat exchangers, and chillers.

The intended functions of the service water system within the scope of license renewal are to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2) and to support fire protection (10 CFR 50.48) requirements.

LRA Table 2.3.3-5 identifies the service water system component types within the scope of license renewal and subject to an AMR.

2.3.3.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.5, FSAR Sections 9.2.1.1 SA, 9.2.1.1 SP, 9.5.1.2.2 SA, 9.5.1.2.2.SP, and Appendix 9.5B SA, as well as the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. On the basis of its review, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results.

The staff noted that license renewal boundary drawings LR-CW-EA-M-22EA01, location E-8, and LR-CW-EA-M-22EA01, locations C-6/7, both depict sections of 10 CFR 54.4(a)(2) piping (lines 036-HBD-8-inch and 039-HBD-8-inch, respectively) that continue to drawing LR-CW-KA-M-22KB02, location B-8. This drawing was not submitted as part of the LRA for the staff's review. By letter dated June 11, 2012, the staff issued RAI 2.3.3.5-1 requesting the applicant to provide sufficient information to locate and describe the license renewal boundary for the above 10 CFR 54.4(a)(2) piping, including additional information describing the extent of the scoping boundary and to verify whether there are additional AMR component types between the continuation and termination of the scoping boundary.

In its response letter, dated July 2, 2012, the applicant stated that the 10 CFR 54.4(a)(2) piping from line 036-HBD-8-inch and line 039-HBD-8-inch, as depicted on license renewal boundary drawing LR-CW-EA-M-22EA01, continues onto the newly created license renewal boundary drawing LR-CW-KA-M-22KB02 and terminates at the breathing air compressor heat exchangers.

The applicant also indicated that due to extension of the scoping boundary of the 10 CFR 54.4(a)(2) piping, the breathing air compressor heat exchangers were added to the compressed air system (LRA Section 2.3.3.8) as being within the scope of license renewal for 10 CFR 54.4(a)(2) with the intended function of structural integrity. As part of its response, the applicant provided revisions to LRA Section 2.3.3.8 and LRA Table 2.3.3-8 to include the heat exchanger component.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.5-1 acceptable because the applicant described the license renewal boundary of the 10 CFR 54.4(a)(2) piping on license renewal boundary drawings LR-CW-EA-M-22EA01 and LR-CW-KA-M-22KB02 and included the breathing air compressor heat exchanger within the scope of license renewal. The staff reviewed the above license renewal boundary drawings and the revisions to LRA Section 2.3.3.8 and LRA Table 2.3.3-8 to confirm the scoping boundary and the inclusion of the heat exchanger component. Therefore, the staff's concern described in RAI 2.3.3.5-1 is resolved.

2.3.3.5.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, FSAR, RAI response, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the service water system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.6 Reactor Makeup Water System

2.3.3.6.1 Summary of Technical Information in the Application

LRA Section 2.3.3.6 states that the purpose of the reactor makeup water system is to store de-aerated water necessary for primary makeup within the plant. Filtered, de-aerated, demineralized water is received from the demineralized water storage and transfer system. The reactor makeup water system components within the scope of license renewal consist of safety-related and nonsafety-related piping.

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

- to provide containment isolation for a containment penetration
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support EQ (10 CFR 50.49) requirements

LRA Table 2.3.3-6 identifies the reactor makeup water system component types within the scope of license renewal and subject to an AMR.

2.3.3.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.6 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. On the basis of its review, the staff did not identify the need for any additional information.

2.3.3.6.3 Conclusion

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

2.3.3.7 Component Cooling Water System

2.3.3.7.1 Summary of Technical Information in the Application

LRA Section 2.3.3.7 states that the purpose of the CCW system is to remove heat from heat exchangers required for the safe shutdown of the reactor and to act as an intermediate heat transfer system between potentially radioactive systems and the service water system or the ESW system to eliminate the possibility of an uncontrolled release of radioactivity.

The intended functions of the CCW system within the scope of license renewal include the following:

- to support maintenance of vital auxiliaries, heat removal, and containment integrity
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support fire protection (10 CFR 50.48) and EQ (10 CFR 50.49) requirements

LRA Table 2.3.3-7 identifies the CCW system component types within the scope of license renewal and subject to an AMR.

2.3.3.7.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.7 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. On the basis of its review, the staff did not identify the need for any additional information.

2.3.3.7.3 Conclusion

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

2.3.3.8 Compressed Air System

2.3.3.8.1 Summary of Technical Information in the Application

LRA Section 2.3.3.8 states that the purpose of the compressed air system is to provide compressed air to the instrument air, service air, breathing air, and containment systems. The compressed air system consists of the compressed air, service gas, and breathing air systems.

The intended functions of the compressed air system within the scope of license renewal include the following:

- to support containment integrity
- to provide capability to shut down the reactor and maintain it in a safe shutdown condition
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support EQ (10 CFR 50.49) and SBO (10 CFR 50.63) requirements

LRA Table 2.3.3-8 identifies the compressed air system component types within the scope of license renewal and subject to an AMR.

2.3.3.8.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.8, FSAR Sections 9.3.1 SP, 9.3.5 SP, and 9.5.10 SP, as well as the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. On the basis of its review, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results.

The staff could not identify seismic anchors or terminations for the 10 CFR 54.4(a)(2) nonsafety-related piping on license renewal boundary drawings LR-CW-KA-M-22KA01, location B-1, and LR-CW-KA-M-22KA04, location F-4. By letter dated June 11, 2012, the staff issued RAI 2.3.3.8-1, requesting the applicant to locate the seismic anchors between the safety-related and nonsafety-related interface and the ends of the 10 CFR 54.4(a)(2) scoping boundary for each piping.

In its response letter, dated July 2, 2012, the applicant stated that the 10 CFR 54.4(a)(2) pipe sections at these four locations are capped downstream from their respective valves, as shown on the license renewal boundary drawings, indicating that the pipe sections are depicted as open-ended pipe sections that do not require a continuation. The applicant added a note to both license renewal boundary drawings to indicate the termination points of the pipe sections.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.8-1 acceptable because the 10 CFR 54.4(a)(2) pipe sections are capped and are represented as open-ended pipe sections that do not require seismic anchors. The staff reviewed and confirmed on the revised license renewal boundary drawings LR-CW-KA-M-22KA01 and LR-CW-KA-M-22KA04 that the notes to clarify the scoping boundaries were included. Therefore, the staff's concern described in RAI 2.3.3.8-1 is resolved.

As indicated in SER Section 2.3.3.5, the applicant also added the breathing air compressor heat exchangers within the scope of license renewal for 10 CFR 54.4(a)(2) in response to RAI 2.3.3.5-1. The staff reviewed the revised LRA Section 2.3.3.8 and LRA Table 2.3.3-8 to confirm that the heat exchanger component was included.

2.3.3.8.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, FSAR, RAI response, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the compressed air system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.9 Nuclear Sampling System

2.3.3.9.1 Summary of Technical Information in the Application

LRA Section 2.3.3.9 states that the purpose of the nuclear sampling system is to collect samples from the reactor coolant, auxiliary, and radwaste systems and bring them to a common location for analysis. The nuclear sampling system consists of the primary sampling system and the radwaste sampling system.

The intended functions of the nuclear sampling system within the scope of license renewal are the following:

- to provide part of the reactor coolant boundary and containment isolation for nuclear sampling system containment penetrations
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support EQ (10 CFR 50.49) requirements based upon the criteria of 10 CFR 54.4(a)(3)

LRA Table 2.3.3-9 identifies the nuclear sampling system component types within the scope of license renewal and subject to an AMR.

2.3.3.9.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.9 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. On the basis of its review, the staff did not identify the need for any additional information.

2.3.3.9.3 Conclusion

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

2.3.3.10 Chemical and Volume Control System

2.3.3.10.1 Summary of Technical Information in the Application

LRA Section 2.3.3.10 states that the purpose of the CVC system is to maintain the water inventory within the RCS; provide seal water injection flow to the RCPs; vary the boron concentration of the RCS; maintain required RCS water chemistry, activity levels, and soluble chemical neutron absorber concentration; and provide reactor coolant purification. The CVC system consists of 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 CVC system consists of various tanks, accumulators, bellows, chillers, pumps, heat exchangers, demineralizers, piping, and valves necessary to control the chemistry, volume, and boric acid content of the reactor coolant.

The purpose of the charging, letdown, and seal water subsystem is to maintain a programmed water level in the pressurizer during all phases of plant operation. This is achieved through a continuous feed-and-bleed process. Charging pumps are provided to take suction from the volume control tank and return the purified reactor coolant to the RCS. A portion of the charging flow is directed to the RCPs seal water injection.

The purpose of the reactor coolant purification and chemistry control subsystem is to maintain desired RCS water chemistry conditions for radioactivity control. The pH control chemical employed is lithium hydroxide. Dissolved hydrogen is used to control and scavenge oxygen. A sufficient partial pressure of hydrogen is maintained in the volume control tank so that the specified concentration of hydrogen is maintained in the reactor coolant. Mixed bed demineralizers are provided in the letdown line to clean up the letdown flow of ionic corrosion products and certain fission products.

The purpose of the reactor makeup control subsystem is to maintain proper reactor coolant inventory and soluble neutron absorber (boric acid) concentration. In addition, the redundant capability exists to supply borated water directly from the RWST to the suction of the charging pumps in an emergency. Automatic makeup compensates for minor leakage of reactor coolant without causing significant changes in the reactor coolant boron concentration.

The purpose of the boron thermal regeneration subsystem is to adjust boron concentration when needed. Downstream of the mixed bed demineralizers, the letdown flow can be diverted to the boron thermal regeneration (BTR) system when boron concentration changes are desired. Although the BTR system is primarily designed to compensate for xenon transients occurring during load follow, it can also be used to handle boron changes during other modes of plant operation.

The intended functions of the CVC system within the scope of license renewal include the following:

- to maintain RCS pressure boundary
- to provide boration and makeup into the RCS
- to supply seal water injection flow to the RCPs seals
- to provide for containment isolation
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)

- to support fire protection (10 CFR 50.48), EQ (10 CFR 50.49), and SBO (10 CFR 50.63) requirements

LRA Table 2.3.3-10 identifies the CVC system component types within the scope of license renewal and subject to an AMR.

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. On the basis of its review, the staff 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 SER Section 2.3 and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the CVC system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.11 Control Building HVAC System

2.3.3.11.1 Summary of Technical Information in the Application

LRA Section 2.3.3.11 states that the purpose of the control building HVAC system is to provide conditioned outside air for the ventilation and cooling to the control building. The control building HVAC system includes the control room filtration and control room pressurization systems. The control building HVAC system removes smoke following a postulated fire and provides a suitable environment for personnel and for Class 1E electrical equipment.

The intended functions of the control building HVAC system within the scope of license renewal include the following:

- to provide a suitable environment for Class 1E electrical equipment under normal conditions and DBEs
- to support habitability of the control building
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support fire protection (10 CFR 50.48) and EQ (10 CFR 50.49) requirements

LRA Table 2.3.3-11 identifies the control building HVAC system component types within the scope of license renewal and subject to an AMR.

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. On the basis of its review, the staff 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 SER Section 2.3 and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the control building HVAC system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.12 Essential Service Water Pumphouse HVAC System

2.3.3.12.1 Summary of Technical Information in the Application

LRA Section 2.3.3.12 states that the purpose of the ESW pumphouse HVAC system is to provide a suitable environment for operation of the safety-related ESW pump motors and associated electrical equipment. The ESW pumphouse HVAC system also provides a suitable environment for operation of the safety-related electrical equipment associated with the UHS cooling tower fans.

The intended functions of the ESW pumphouse HVAC system within the scope of license renewal include the following:

- to provide a suitable environment for operation of the ESW pumps and the electrical equipment associated with the UHS cooling tower fans
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support fire protection (10 CFR 50.48) requirements based on the criteria of 10 CFR 54.4(a)(3)

LRA Table 2.3.3-12 identifies the ESW pumphouse HVAC system component types within the scope of license renewal and subject to an AMR.

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. On the basis of its review, the staff 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 SER Section 2.3 and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the ESW pumphouse HVAC system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.13 Auxiliary Building HVAC System

2.3.3.13.1 Summary of Technical Information in the Application

LRA Section 2.3.3.13 states that the purpose of the auxiliary building HVAC system is to maintain a suitable environment for safety-related equipment under normal conditions and DBEs. The auxiliary building HVAC system process airborne particulates in the auxiliary building and exhaust the air from the containment.

The intended functions of the auxiliary building HVAC system within the scope of license renewal include the following:

- to provide isolation of the auxiliary building and maintain a suitable environment for safety-related equipment in the auxiliary building under normal conditions and DBEs
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support fire protection (10 CFR 50.48) and EQ (10 CFR 50.49) requirements based upon the criteria of 10 CFR 54.4(a)(3)

LRA Table 2.3.3-13 identifies the auxiliary building HVAC system component types within the scope of license renewal and subject to an AMR.

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. On the basis of its review, the staff 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 SER Section 2.3 and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concluded that the applicant appropriately identified the auxiliary building HVAC system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.14 Fuel Building HVAC System

2.3.3.14.1 Summary of Technical Information in the Application

LRA Section 2.3.3.14 states that the purpose of the fuel building HVAC system is to provide conditioned outside air to the fuel building for ventilation, cooling, or heating.

The intended functions of the fuel building HVAC system within the scope of license renewal include the following:

- to provide a suitable environment for the operation of the safety-related spent fuel pool cooling pumps
- to isolate the fuel building HVAC and provide a flow path for the control of radioactivity release during a fuel handling accident

- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support fire protection (10 CFR 50.48) requirements based on the criteria of 10 CFR 54.4(a)(3)

LRA Table 2.3.3-14 identifies the fuel building HVAC system component types within the scope of license renewal and subject to an AMR.

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. On the basis of its review, the staff 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 SER Section 2.3 and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the fuel building HVAC system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the fuel building system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.15 Miscellaneous Building HVAC System

2.3.3.15.1 Summary of Technical Information in the Application

LRA Section 2.3.3.15 states that the purpose of the miscellaneous buildings HVAC system is to provide conditioned outside air to the tendon access gallery for cooling or heating and to provide outside air to the main steam enclosure building for ventilation and cooling or heating. The miscellaneous buildings HVAC system provides a suitable atmosphere for personnel and equipment within the access tunnel and auxiliary boiler room and for the electric motor drivers and safety-related motor driven auxiliary feedwater pumps within the auxiliary feedwater pump room. The miscellaneous buildings HVAC system also provides heating for the RWST valve house, the reactor makeup water storage tank valve house, and the condensate and demineralized water pipe tunnels.

The intended functions of the miscellaneous buildings HVAC system within the scope of license renewal include the following:

- to provide a suitable environment for the electric motor drivers in the motor-driven auxiliary feedwater pump rooms
- to provide the capability to isolate HVAC system penetrations of the auxiliary building boundary
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support fire protection (10 CFR 50.48) and EQ (10 CFR 50.49) requirements

LRA Table 2.3.3-15 identifies the miscellaneous buildings HVAC system component types within the scope of license renewal and subject to an AMR.

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. On the basis of its review, the staff 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 SER Section 2.3, and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the miscellaneous buildings HVAC system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.16 Diesel Generator Building HVAC System

2.3.3.16.1 Summary of Technical Information in the Application

LRA Section 2.3.3.16.1 states that the purpose of the diesel generator building HVAC system is to provide combustion air and cooling for the diesel generators.

The intended functions of the diesel generator building HVAC system within the scope of license renewal are to provide combustion air and a suitable environment to the diesel generators during DBEs and to support fire protection (10 CFR 50.48) requirements.

LRA Table 2.3.3-16 identifies the diesel generator building HVAC system component types within the scope of license renewal and subject to an AMR.

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. On the basis of its review, the staff 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 SER Section 2.3, and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the diesel generator building HVAC system mechanical components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.17 Radwaste Building HVAC System

The NRC staff issued Callaway License Amendment 206 by letter dated January 13, 2014, which authorizes the applicant to implement a new risk-informed, performance-based Fire Protection program based upon 10 CFR 50.48(c) and National Fire Protection Association (NFPA) 805, “Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants, 2001 Edition” (NFPA 805). As a result of this license amendment, the radwaste building HVAC system is deleted from the scope of license renewal. On the basis of its review, the staff concludes that the deletion is acceptable.

2.3.3.18 Turbine Building HVAC System

2.3.3.18.1 Summary of Technical Information in the Application

LRA Section 2.3.3.18 states that the purpose of the turbine building HVAC system is to provide outside air for heating, ventilation, and cooling for portions of the turbine building and the communication corridor. The turbine building HVAC system also provides isolation of the auxiliary building following a DBE.

The intended functions of the turbine building HVAC system within the scope of license renewal are to provide capability to isolate HVAC system penetrations of the auxiliary building boundary following a DBE and to support fire protection (10 CFR 50.48) and EQ (10 CFR 50.49) requirements.

LRA Table 2.3.3-18 identifies the turbine building HVAC system component types within the scope of license renewal and subject to an AMR.

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. On the basis of its review, the staff 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 SER Section 2.3 and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the turbine building HVAC system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.3.19 Containment Cooling System

2.3.3.19.1 Summary of Technical Information in the Application

LRA Section 2.3.3.19 states that the purpose of the containment cooling system is to maintain a suitable environment for equipment within the containment during normal operation and to remove heat and provide mixing of the containment atmosphere to prevent pockets of hydrogen from forming during DBEs.

The intended functions of the containment cooling system within the scope of license renewal include the following:

- to provide containment isolation, heat removal, and a suitable containment atmosphere
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support fire protection (10 CFR 50.48) and EQ (10 CFR 50.49) requirements

LRA Table 2.3.3-19 identifies the containment cooling system component types within the scope of license renewal and subject to an AMR.

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. On the basis of its review, the staff 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 SER Section 2.3 and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant has appropriately identified the containment cooling system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes 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 Fire Protection System

2.3.3.20.1 Summary of Technical Information in the Application

LRA Section 2.3.3.20 states that the purpose of the fire protection system is to detect, alarm, control, and extinguish any fire that might occur within the plant area. Fire detection devices are provided throughout the plant area to detect fire, alert the control room operators, and activate fire alarms. Personnel alarms are provided in areas where toxic inert gas is used for fire protection. The fire protection system also supports the safe shutdown of the plant by minimizing the effects of fire on plant SSCs important to safety.

The intended functions of the fire protection system within the scope of license renewal include the following:

- to support containment pressure boundary
- to maintain integrity of nonsafety-related SSCs such that no physical interaction with safety-related SSCs could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to perform functions that demonstrate compliance with NRC regulations for fire protection (10 CFR 50.48)

LRA Table 2.3.3-20 identifies the fire protection system component types within the scope of license renewal and subject to an AMR.

2.3.3.20.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.20; FSAR Section 9.5.1, Appendices 9.5A and 9.5B; and license renewal boundary drawings using the evaluation methodology described in SER Section 2.3 and guidance in SRP-LR Section 2.3. During its review, the staff evaluated the system functions described in the LRA and FSAR to verify that the applicant had not omitted from the scope of license renewal any components with intended functions in accordance with 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as within the scope of license renewal to verify that the applicant had not omitted any passive or long-lived components subject to an AMR, in accordance with 10 CFR 54.21(a)(1).

The staff also reviewed the following fire protection documents cited in the CLB listed in Callaway Operating License Condition 2.C(5):

- NUREG-0830, "Safety Evaluation Report Related to the Operation of Callaway Plant, Unit No 1," October 1981
- NUREG-0830, Supplement No 3, "Safety Evaluation Report Related to the Operation of Callaway Plant, Unit No. 1," May 1984

Based on the documents above, the staff reviewed Callaway compliance to 10 CFR 50.48, "Fire protection" (i.e., approved Fire Protection Program). The review consisted of a point-by-point comparison with Appendix A to the Branch Technical Position Chemical and Mechanical Engineering Branch 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants," Revision 2, July 1981, documented in the Standardized Nuclear Unit Power Plant System (SNUPPS) FSAR Section 9.5.1, Appendices 9.5A and 9.5B.

During its review of LRA Section 2.3.3.20, the staff identified areas for which additional information was necessary to complete its review of the applicant's scoping and screening results.

The staff noted that license renewal boundary drawings LR-CW-KC-M-22KC01 and LR-CW-KC-M-22KC02 show the following fire water systems or components as not within the scope of license renewal (i.e., not colored in green):

Table 2.3-1 Fire Water Systems or Components Not within the Scope of License Renewal

LRA Drawing	Systems and Components	Location
LR-CW-KC-M-22KC01	Turbine Generator Bearing	A4
	North Area Below Turbine (El. 2000'-0")	C5
	North Area Below Turbine (El. 2033'-0")	C4
	Unit 1 Auxiliary Transformers XMA02, XMA01B ø B, and XMA01C ø C	D2
	Main Transformers (3) XMA01A ø A	F2
	Station Service Transformers XPB03 and XPB04	H5
	Condenser Pit	A6
	South Area Below Turbine (El. 2000'-0")	D7
	South Area Below Turbine (El. 2033'-0")	A7
	Hydrogen Seal Oil Unit	D2
LR-CW-KC-M-22KC02	Auxiliary Boiler Room	A2

By letter dated June 11, 2012, the staff issued RAI 2.3.3.20-1 requesting that the applicant verify whether the fire water systems and components listed above are within the scope of license renewal in accordance with 10 CFR 54.4(a), and subject to an AMR in accordance with 10 CFR 54.21(a)(1). If water systems and components were 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 its response letter dated July 2, 2012, the applicant stated that the fire water suppression systems for the main, station service, and unit auxiliary transformers are not within the scope of license renewal and are not subject to an AMR because these transformers are 50 ft away from

the building containing safety-related systems. The applicant also cited NUREG-0830, "Safety Evaluation Report related to the operation of Callaway Plant, Unit No. 1," Section 7.4, "Systems Required for Safe Shutdown," as stating the following:

> The onsite power system is provided with preferred power from the offsite system through two independent and redundant sources of power. The Class 1E AC system loads required to maintain the plant at safe shutdown or to mitigate the consequences of an accident are separated into two load groups. These are powered from separate ESF transformers when offsite power is available or from two independent diesel generators (one per load group) when offsite power is not available.

In its response to RAI 2.3.3.20-1 regarding outside oil filled transformer fire suppression systems, the applicant stated that the outside oil filled transformers are located 15.2 m (50 ft) away from buildings containing safety-related systems, and satisfy the Appendix A to branch technical position APCSB 9.5-1 requirements for spatial separation distance. Based on its review, the staff finds the applicant's response acceptable because it clarifies that the main, station service and unit auxiliary transformers' fire suppression systems and their associated components have no license renewal intended functions. The staff reviewed the Callaway response to branch technical position APCSB 9.5-1, Position D.1(h), that the outside oil-filled transformers are 15.2 m (50 ft) away from the buildings containing safety-related systems. Therefore, the staff finds that a fire from the outdoor transformers cannot affect safety-related equipment and that the fire suppression systems for the outside transformers were correctly excluded from the scope of license renewal and not subject to an AMR. The staff's concern for this portion of the RAI is resolved.

For the auxiliary boiler room fire suppression system, the applicant stated that the auxiliary boiler room is separated from adjoining safe-shutdown areas by 3-hour-rated fire barriers and contains no post-fire safe-shutdown equipment, circuits, or safety-related equipment. Therefore, the fire water suppression system for the auxiliary boiler room is not within the scope for license renewal and not subject to an AMR.

In evaluating this response, the staff found that it was incomplete and that review of a portion of LRA Section 2.3.3.20 could not be completed. The applicant responded to the RAI by removing the auxiliary boiler room fire suppression system and components from the scope of license renewal as not being subject to an AMR. The staff finds this contrary to the FSAR, which includes the original Callaway fire protection safety evaluation, NUREG-0830, "Safety Evaluation Report related to the Operation of Callaway Plant, Unit No. 1," dated October 1981, as the CLB.

The staff, therefore, does not agree with the applicant's proposed change to exclude the auxiliary boiler room fire suppression system and components from the scope of license renewal, as stated in 10 CFR 54.4(a)(3), because it is required for compliance with 10 CFR 50.48 and, therefore, subject to an AMR pursuant to 10 CFR 54.21(a)(1). Additionally, the aging management program (AMP) must demonstrate that the aging effects associated with the fire protection system components, if in scope, are adequately managed so that there is reasonable assurance that the system components will perform their intended function(s) in accordance with the CLB during the period of extended operation, as required by 10 CFR 50.21(a)(3).The staff finds that the auxiliary boiler room fire suppression system and components should not be excluded on the basis that they are not required to function to suppress a fire or are not required for compliance with 10 CFR 50.48, without considering the

CLB. Therefore, the staff identified its concern for this portion of RAI 2.3.3.20-1 as part of Open Item 2.3.3.20-1, Part (a).

By letter dated March 29, 2013, the staff issued followup RAI 3.3.2.20-1a, requesting that the applicant provide additional information on its basis to exclude from the scope of license renewal those SSCs in the fire suppression systems associated with the auxiliary boiler room. The staff further requested that, if the auxiliary boiler room fire suppression system SSCs are within the scope of license renewal, then the LRA and boundary drawing should be revised accordingly.

In a letter dated April 29, 2013, the applicant responded to RAI 2.3.3.20-1a and stated the auxiliary boiler room fire suppression system had been added to the Boundary Drawing LR-CW-KC-M-22KC02.

Based on its review, the staff finds the applicant's response acceptable because it clarifies that the auxiliary boiler room fire suppression system in question is required to meet the scoping criteria of 10 CFR 54.4(a)(3) and is required for compliance with 10 CFR 50.48. The applicant included the auxiliary boiler room fire suppression system within the scope of license renewal and updated its license renewal documents. The staff's concern described in this portion of RAI 2.3.3.20-1a is resolved.

In its response dated April 29, 2013, the applicant stated that, for the turbine building north area below turbine deck (El. 2000'-0"), north area below turbine deck (El. 2033'-0"), south area below turbine deck (El. 2000'-0"), and south area below turbine deck (El. 2033'-0"), there was no post-fire safe shutdown or safety-related equipment in the turbine building. The applicant stated that the fire water suppression systems for these turbine building locations were installed as a "good practice" for loss prevention and property protection only and were not required to meet the criteria of 10 CFR 50.48. Therefore, the applicant concluded that the fire water suppression systems for these areas of the turbine building were not within the scope of license renewal and not subject to an AMR.

In evaluating this response, the staff found that it was incomplete and that review of a portion of LRA Section 2.3.3.20 could not be completed. The applicant responded to the RAI by removing the fire suppression systems and components in the north area below the turbine deck at Elevations 2000'-0" and 2033'-0" and south area below the turbine deck at Elevations 2000'-0" and 2033'-0" in the turbine building from the scope of license renewal as not being subject to an AMR. The applicant further stated that the turbine building does not contain post-fire safe-shutdown equipment and a fire in the turbine building will not prevent plant safe-shutdown. Furthermore, the applicant stated that the fire suppression systems in question are for insurance and property protection purposes. The staff finds this contrary to the FSAR which includes the original Callaway fire protection Safety Evaluation NUREG-0830, dated October 1981, as the CLB.

The staff, therefore, does not agree with the applicant's proposed change to exclude the above turbine building fire suppression systems and components from scope, as stated in 10 CFR 54.4(a)(3), because they are required for compliance with 10 CFR 50.48 and, therefore, subject to an AMR pursuant to 10 CFR 54.21(a)(1). Additionally, the AMP must demonstrate that the aging effects associated with the fire protection system components, if in scope, are adequately managed, so that there is reasonable assurance that the system components will perform their intended function(s) in accordance with the CLB during the period of extended operation as required by10 CFR 50.21(a)(3). The turbine building fire suppression systems and components in question should not be excluded on the basis that they are not required to

function to suppress a fire or are not required for compliance to 10 CFR 50.48 and Appendix R, without considering the CLB. Therefore, the staff identified its concern for this portion of RAI 2.3.3.20-1 as part of Open Item 2.3.3.20-1, Part (a).

By letter dated March 29, 2013, the staff issued follow-up RAI 3.3.2.20-1a, requesting that the applicant provide additional information on its basis to exclude from the scope of license renewal those SSCs in the fire suppression systems in the north area below turbine deck at Elevations 2000'-0" and 2033'-0" and south area below turbine deck at Elevations 2000'-0" and 2033'-0" in the turbine building. The staff further requested that, if these fire suppression systems SSCs are within the scope of license renewal, then revise the LRA and boundary drawing accordingly.

In a letter dated April 29, 2013, the applicant responded to RAI 2.3.3.20-1a and stated fire suppression systems in the north area below turbine deck at Elevations 2000'-0" and 2033'-0" and south area below turbine deck at Elevations 2000'-0" and 2033'-0" in the turbine building added to the Boundary Drawings LR-CW-KC-M-22KC01, LR-CW-KC-M-22KC08, and LR-CW-KC-M-22KC09. Further, the applicant stated that LRA Section 2.3.3.20 was revised as shown in LRA Amendment 24 in Enclosure 2 to add a new boundary drawing for the fire protection system located in the turbine building. LRA Section 3.3.2.1.20 and Table 3.3.2-20 have also been revised as shown in LRA Amendment 24, Enclosure 2, to add the following:

- Selective leaching as an aging effect for copper alloy fire protection system components with greater than 15 percent zinc.
- Aging management of copper alloy fire protection system components with greater than 15 percent zinc by the Selective Leaching program (B2.1.19) and Fire Water System program (B2.1.14)
- Aging management of carbon steel flow orifices

Based on its review, the staff finds the applicant's response acceptable because it clarifies that the turbine building fire suppression system in question is required to meet the scoping criteria of 10 CFR 54.4(a)(3) and is required for compliance with 10 CFR 50.48. The applicant has included the turbine building fire suppression system within the scope of license renewal and updated its license renewal document. The staff's concern described in this portion of RAI 2.3.3.20-1a is resolved**.**

For the turbine generator bearing, condenser pit, and hydrogen seal oil unit fire suppression systems, the applicant stated that these areas are separated from the adjacent auxiliary building by 3-hour-rated fire barrier walls. The applicant also stated that fire suppression systems and components in question are not within the scope of license renewal and subject to an AMR because these areas do not contain post-fire safe-shutdown equipment, and a fire in this area will not prevent safe shutdown.

In evaluating this response, the staff found that it was incomplete and that review of a portion of LRA Section 2.3.3.20 could not be completed. The applicant responded to the RAI by removing the turbine generator bearing, condenser pit, and hydrogen seal oil unit fire suppression systems and components from the scope of license renewal as not being subject to an AMR. The applicant further stated that the turbine generator bearing, condenser pit, and hydrogen seal oil unit do not contain post-fire safe-shutdown equipment and a fire in these areas will not prevent plant safe-shutdown. The staff finds this contrary to the FSAR, which includes the original Callaway fire protection safety evaluation NUREG-0830, dated October 1981, as the CLB.

The staff, therefore, does not agree with the applicant's proposed change to exclude the above fire suppression systems and components from the scope of license renewal as stated in 10 CFR 54.4(a)(3) because they are required for compliance with 10 CFR 50.48 and, therefore, subject to an AMR pursuant to 10 CFR 54.21(a)(1). Additionally, the AMP must demonstrate that the aging effects associated with the fire protection system, if in scope, are adequately managed so that there is reasonable assurance that the system components will perform their intended function(s) in accordance with the CLB during the period of extended operation, as required by 10 CFR 50.21(a)(3). The turbine generator bearing, condenser pit, and hydrogen seal oil unit fire suppression systems and components in question should not be excluded on the basis that they are not required to function to suppress a fire or are not required for compliance with 10 CFR 50.48, and Appendix R, without considering the CLB. The staff found the proposed changes to the Callaway-approved fire protection system to be unacceptable. Therefore, the staff identified its concern as part of Open Item 2.3.3.20-1, Part (a).

By letter dated March 29, 2013, the staff issued followup RAI 3.3.2.20-1a, requesting that the applicant provide additional information on its basis to exclude from the scope of license renewal those SSCs in the fire suppression systems associated with the turbine generator bearing, condenser pit, and hydrogen seal oil unit. The staff further requested that, if these fire suppression systems SSCs are within the scope of license renewal, then the LRA and boundary drawing should be revised accordingly.

In a letter dated April 29, 2013, the applicant responded to RAI 2.3.3.20-1a and stated the turbine generator bearing, condenser pit, and hydrogen seal oil unit fire suppression systems have been added to the Boundary Drawings LR-CW-KC-M-22KC01, LR-CW-KC-M-22KC08, and LR-CW-KC-M-22KC09.

Based on its review, the staff finds the applicant's response acceptable because it clarifies that the turbine generator bearing, condenser pit, and hydrogen seal oil unit fire suppression systems in question are required to meet the scoping criteria of 10 CFR 54.4(a)(3) and are required for compliance with 10 CFR 50.48. The applicant has included the turbine generator bearing, condenser pit, and hydrogen seal oil unit fire suppression systems within the scope of license renewal and updated its license renewal document. The staff's concern described in this portion of RAI 2.3.3.20-1a is resolved.

The staff's concerns in RAI 2.3.3.20-1(a) are resolved, and Open Item 2.3.3.20-1, Part (a) is closed.

By letter dated June 11, 2012, the staff issued RAI 2.3.3.20-2, requesting the applicant to determine if LRA Tables 2.3.3-20 and 3.3.2-20 should include the following fire protection components:

- fire hose connections and hose racks
- sprinklers
- diesel fire pump heat exchanger (bonnet, shell, and tubes)
- lubricating oil collection system components for each RCP
- floor drains and curbs for fire-fighting water
- dikes for oil spill confinement
- sprinkler system water curtain in the auxiliary building equipment hatchway
- filter housing
- diesel generator room roof heat vents

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

In its response letter dated July 2, 2012, the applicant provided the results of the scoping and screening for the listed fire protection component types as follows:

> Fire Hose Connections and Hose Racks:
>
> Fire hose connections and hose racks are evaluated as the component type "hose station." LRA Table 2.3.3-20 identifies hose stations as components within the scope of license renewal and subject to an AMR. The [AMR] for hose station components is provided in LRA Table 3.3.2-20.
>
> Sprinklers:
>
> Sprinklers are evaluated as the component type "spray nozzle." LRA Table 2.3.3-20 identifies spray nozzles as components within the scope of license renewal and subject to an AMR. The [AMR] for spray nozzle components is provided in LRA Table 3.3.2-20.
>
> Diesel Fire Pump Heat Exchanger ([B]onnet, [S]hell, and [T]ubes):
>
> [The] diesel fire pump heat exchanger is evaluated as the component type "heat exchanger (DFP jacket water)," which includes a main component and subcomponent representing the shell and tubes, respectively. Channels, channel covers, and bonnets are included as part of the heat exchanger subcomponent type shell. LRA Table 2.3.3-20 identifies heat exchanger (DFP jacket water) […] components [as] within the scope of license renewal and subject to an AMR. The [AMR] for the heat exchanger (DFP jacket water) components is provided in LRA Table 3.3.2-20.
>
> Lubricating [O]il [C]ollection [S]ystem [C]omponents for each [R]eactor [C]oolant [P]ump:
>
> The system description in LRA Section 2.3.3.27 for the floor and equipment drainage system includes reactor coolant lubricating oil drain tanks for the [RCP] lubricating oil collection system. LRA Table 2.3.3-27 identifies piping, valves, splash guards, and tanks of the RCP lubricating oil collection system as components within the scope of license renewal and subject to an AMR. The AMR for components associated with the [RCP] lubricating oil collection system is provided in LRA Table 3.3.2-27.
>
> Floor Drains and Curbs for Fire-Fighting Water:
>
> Floor drains for fire-fighting water are evaluated as the component type "piping." LRA Tables 2.3.3-26 (oil waste system) and 2.3.3-27 (floor and equipment drainage system) identify piping (floor drains) as components within the scope of license renewal and subject to an AMR. The AMR for piping (floor drains) is provided in LRA Tables 3.3.2-26 and 3.3.2-27.

Curbs for fire-fighting water are evaluated as part of the component type "concrete elements" with a "flood barrier" or "direct flow" function(s) assigned to them. LRA Tables 2.4-2 ([c]ontrol [b]uilding), 2.4-3 ([a]uxiliary [b]uilding), and 2.4-5 ([d]iesel [g]enerator [b]uilding) identify concrete elements (curbs for fire-fighting water) as components within the scope of license renewal and subject to an AMR. The [AMR] for concrete elements associated with curbs for fire-fighting water is provided in LRA Table 3.5-1.

Dikes for Oil Spill Confinement:

[…]

Dikes for oil spill confinement are evaluated as part of the component type "concrete elements" with a "structural pressure boundary" function assigned to them. LRA Tables 2.4.3 ([a]uxiliary [b]uilding) and 2.4.5 ([d]iesel [g]enerator [b]uilding) identify concrete elements (dikes for oil spill confinement) as components within the scope of license renewal and subject to an AMR. The [AMR] for concrete elements associated with dikes for oil spill confinement is provided in LRA Table 3.5-1.

Sprinkler System Water Curtain for the Auxiliary Building Equipment Hatchway:

[…]

Sprinkler system water curtains for the [a]uxiliary [b]uilding [e]quipment [h]atchways are evaluated as component types "valve," "piping," and "spray nozzle." LRA Table 2.3.3-20 identifies components associated with the sprinkler system water curtain to be within the scope of license renewal and subject to an AMR. The [AMR] for the components associated with the sprinkler system water curtains for the auxiliary building hatchways are provided in LRA Table 3.3.2-20.

Filter Housing:

Filter housings are evaluated as the component type "filter." LRA Table 2.3.3-20 identifies filters as components within the scope of license renewal and subject to an AMR. The [AMR] of filters is provided in LRA Table 3.3.2-20.

Diesel Generator Room Roof Heat Vents:

[…]

The exhaust air flow path is evaluated as part of the component types "damper," "ductwork," and "louvers (evaluated as structural steel components)." LRA Table 2.3.3-16 (diesel generator building HVAC system) identifies the fan and ductwork components associated with the exhaust air flow path as components within the scope of license renewal and subject to an AMR. LRA Table 2.4-5 (diesel generator building) identifies the louver (structural steel) components associated with the exhaust air flow path as components within the scope of license renewal and subject to an AMR. The AMR for components associated with the exhaust air flow path is provided in LRA Table 3.3.2-16 and LRA Table 3.5.2-5.

In reviewing its response to the RAI, the staff found that the applicant had addressed and resolved each item in the RAI, as discussed in the following paragraphs.

Although the description of the "hose station" line item provided in LRA Table 2.3.3-20 does not list these components specifically, the applicant stated that it considers this line item to include the fire hose connection and hose racks. LRA Table 3.3.2-20 provides the AMR results of these components.

In its response, the applicant also confirmed that "sprinklers" are included in component type "spray nozzle" in LRA Table 2.3.3-20, with AMR results provided in LAR Table 3.3.2-20.

The applicant indicated that the diesel fire pump heat exchanger (bonnet, shell, and tubes) is included in the category of "heat exchanger (DFP jacket water)." This line item is included in LRA Table 2.3.3-20, with the AMR results provided in LRA Table 3.3.2-20.

The lubricating oil collection system is addressed in LRA Section 2.3.3.27 and LRA Table 2.3.3-27, which identify this as components within the scope of license renewal and subject to an AMR, with the AMR results provided in LRA Table 3.3.2-27.

The floor drains are included in LRA Tables 2.3.3-26 and 2.3.3.27 under component type "piping," with the AMR results provided in LRA Tables 3.3.2-26 and 3.3.2-27. Curbs are included in the structural component type "concrete elements" in LRA Tables 2.4-2, 2.4-3, and 2.4-5, with the AMR results provided in LRA Table 3.5-1.

In addition, the applicant indicated that the dikes for oil spill confinement are included in the structural AMR under component type "concrete elements" in LRA Tables 2.4-3 and 2.4-5, with the AMR results provided in LRA Table 3.5-1.

The sprinkler system water curtain in the auxiliary building equipment hatchway is included in component types "valve," "piping," and spray nozzle," in LRA Table 2.2.3-20 with the AMR results provided in LRA Table 3.3.2-20.

The applicant confirmed that the filter housings are subject to an AMR under component type "filter." The filter housing is listed in LRA Tables 2.3.3-20 and 3.3.2-20 in the "filter" component type.

The applicant confirmed that the diesel generator building exhaust flow components are within the scope of license renewal and subject to an AMR. LRA Table 2.3.3-16 identifies components associated with the diesel generator building exhaust flow path with the AMR results in LRA Tables 33.2-16 and 3.5.2-5.

Based on its review, the staff found the applicant's response to RAI 2.3.3.20-2 acceptable because the applicant provided clarification that the fire protection system and components listed above are within the scope of license renewal and subject to an AMR as required by 10 CFR 54.4(a) and 54.21(a)(1) respectively. The staff's concern described in RAI 2.3.3.20-2 is resolved.

By letter dated August 29, 2011, the applicant submitted a license amendment request (LAR) to transition the existing Fire Protection Program for Callaway to a risk-informed, performance-based program based on National Fire Protection Association Standard 805 (NFPA 805), "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants," 2001 Edition, in accordance with 10 CFR 50.48(c). Subsequent to the

NFPA 805 LAR the applicant submitted to the staff, by letter dated December 15, 2011, an application for renewal of Operating License NPF-30 for Callaway.

It is unclear to the staff if there are Fire Protection Program plant modifications planned for transition to NFPA 805 that affect the existing Fire Protection Program and SSCs for license renewal. By letter dated June 11, 2012, the staff issued RAI 2.3.3.20-3, requesting that the applicant identify and discuss the changes associated with the NFPA 805 transition and their effect on LRA Tables 2.3.3-20 and 3.3.2-20. In addition, the staff requested that the applicant provide a gap analysis of Tables 2.3.3-20 and 3.3.2-20 of the LRA identifying any differences between the existing plant configuration and NFPA 805 post-transition configuration. The staff requested that the applicant summarize the results and the impacts of these gaps on the Fire Protection Program described in LRA Tables 2.3.3-20 and 3.3.2-20. The staff also requested a list of the fire protection SSCs, including, but not limited to, structural fire barriers (e.g., fire walls and slabs, fire doors, fire barrier penetration seals, fire dampers, fire barrier coatings and wraps, equipment and personnel hatchways and plugs, and metal siding), which will be added or removed, based on the NFPA 805 transition, from the scope of license renewal in accordance with 10 CFR 54.4(a), and whether they are subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In its response letter dated July 2, 2012, the applicant stated that the Callaway NFPA 805 LAR is presently under the staff's review and is subject to change as a result of those reviews. The applicant stated that it plans to perform the requested gap analysis upon issuance of the draft NFPA 805 SER. The applicant acknowledged that the staff requires the license renewal gap analysis to support development of the SER for license renewal. The applicant revised LRA Table A4-1 (LRA Amendment 4) to add Commitment No. 39, which requires the applicant to provide a gap analysis of LRA Tables 2.3.3-20 and 3.3.2-20 identifying differences between the existing and NFPA 805 post-transition changes before January 11, 2013. If the draft NFPA 805 SER is not available in Fall 2012, the applicant will provide an alternate schedule to address this commitment.

Based on its review, the staff found the applicant's response to RAI 2.3.3.20-3 only partially acceptable because, while it provided Commitment No. 39 which resolved some of the staff's concerns regarding the need for a gap analysis, it was only able to provide a proposed schedule for the gap analysis between the existing and post-transition fire protection program changes. The staff finds that the gap analysis cannot yet be performed. The license renewal Commitment No. 39, Table A4-1, provides the schedule for gap analysis of LRA Tables 2.3.3-20 and 3.3.2-20 to identify differences between the existing and future NFPA 805 post-transition changes. The applicant will summarize the results and the impacts of these gaps on the fire protection program described in LRA Tables 2.3.3-20 and 3.3.2-20, based on the transition to the NFPA 805 nuclear safety capabilities before January 11, 2013, contingent upon the staff issuing the draft NFPA 805 LAR SER in Fall 2012. The applicant further stated in Commitment No. 39 that if the draft NFPA 805 LAR SER is not available in Fall 2012, it will provide an alternate schedule to address this commitment.

By letter dated January 10, 2013, the applicant revised Commitment No. 39 schedule with new dates to address the staff concern regarding the gap analysis of LRA Tables 2.3.3-20 and 3.3.2-20 to identify differences between the existing and future NFPA 805 post-transition changes. According to the revised schedule, the applicant would summarize the results and the impacts of these gaps on the fire protection program described in LRA Tables 2.3.3-20 and 3.3.2-20, based on the future transition to the NFPA 805 nuclear safety capabilities before March 25, 2013, contingent upon the staff issuing the draft NFPA 805 LAR SER in

February 2013. The applicant further stated in Commitment No. 39 that if the draft NFPA 805 LAR SER is not available in February 2013, it will provide an alternate schedule to address this commitment.

The staff reviewed the applicant's revised Commitment No. 39 and noted that the applicant should not perform its gap analysis of LRA Tables 2.3.3-20 and 3.3.2-20 based on a draft NFPA 805 LAR safety evaluation report. Commitment No. 39 should be based on the final NFPA 805 LAR safety evaluation report. Therefore, the staff identified this concern as Open Item 2.3.3.20-1, Part (b).

The NRC staff issued final NFPA 805 license amendment safety evaluation report January 13, 2014 (ADAMS Accession No. ML13274A596), to comply with 10 CFR 50.48(c) and the applicant provided its gap analysis (Amendment 31) based on the approved NFPA 805 fire protection program by letter dated February 14, 2014. The staff's initial review found that this submittal lacked sufficient details to reach conclusions as to the adequacy of the gap analysis and the changes Ameren Missouri would make to the SSCs, the fire protection AMP, as well as any other affected AMPs as a result of transition to NFPA 805. The applicant subsequently submitted a supplement to its gap analysis (Amendment 33) by letter dated April 15, 2014, with additional information and sufficient details based on its NFPA 805 fire protection program.

The staff reviewed the applicant's NFPA 805 gap analysis for LRA Tables 2.3.3-20 and 3.3.2-20 and found that it is consistent with the Callaway August 29, 2011, NFPA 805 Transition Report and final approved safety evaluation report. The staff noted that the applicant specifically removed structural fire barriers (e.g., fire wall and slabs, fire doors, fire barrier penetration seals, fire dampers, fire barriers coatings/wraps, equipment/personnel hatchways and plugs, metal siding) from the scope of license renewal and cited them as not being subject to an AMR. In addition, the staff noted that in LRA Amendment 33, the applicant used its scoping and screening methodology from its NFPA 805 fire protection program based on the NFPA 805 transition report. Only fire protection suppression systems and fire protection features (fire barriers) located in risk-significant fire areas are included in the scope of license renewal and subject to an AMR. Callaway Transition Report, Table 4-3, "Summary of NFPA 805 Compliance Basis and Required Fire Protection Features," and Attachment C, "Table B-3 Fire Area Transition," provide the compliance basis and fire protection systems and features required to meet 10 CFR 50.48(c).

The staff noted that LRA Amendment 33 (i.e., gap analysis) provides details on the plant water supply systems, water-based and gaseous fire suppression systems, and addresses differences in the license renewal application between the existing and NFPA 805 post-transition fire protection program as reported in the approved NFPA 805 safety evaluation dated January 13, 2014. The applicant identified and discussed changes associated with the NFPA 805 transition and their effect on LRA Section 2.3.3-20, "Fire Protection System."

The staff reviewed the applicant's revised Commitment No. 39 gap analysis (LRA Amendment 33) which compares NFPA 805 and license renewal scope differences by identifying SSCs that are not currently within the scope of license renewal and subject to an AMR; and SSCs within the scope of license renewal for fire protection, but which are no longer required by the NFPA 805 fire protection program. The staff concludes that the applicant appropriately identified changes associated with the NFPA 805 transition.

The staff's concerns in RAI 2.3.3.20-1(b) are resolved and OI 2.3.3.20-1, Part (b) is closed. Therefore, OI 2.3.3.20-1 is closed.

2.3.3.20.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, LRA Amendments 31 and 33, FSAR, RAI responses, and license renewal boundary drawings, the staff concludes that the applicant has appropriately identified the fire protection system components within the scope of license renewal, as required by 10 CFR 54.4(a) and subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.21 Emergency Diesel Engine Fuel Oil Storage and Transfer System

2.3.3.21.1 Summary of Technical Information in the Application

LRA Section 2.3.3.21 states that the purpose of the emergency diesel engine fuel oil storage and transfer system is to provide onsite storage and transfer of fuel oil to the two emergency diesel engines. For each diesel engine, there is an underground storage tank capable of providing fuel oil for 7 days of operation.

The intended functions of the emergency diesel engine fuel oil storage and transfer system within the scope of license renewal include the following:

- to support the capability to safely shut down the reactor and maintain it in a safe condition
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support fire protection (10 CFR 50.48) and EQ (10 CFR 50.49) requirements

LRA Table 2.3.3-21 identifies the emergency diesel engine fuel oil storage and transfer system component types within the scope of license renewal and subject to an AMR.

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. On the basis of its review, the staff 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 SER Section 2.3 and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant has appropriately identified the emergency diesel engine fuel oil storage and transfer system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes 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 Standby Diesel Generator Engine System

2.3.3.22.1 Summary of Technical Information in the Application

LRA Section 2.3.3.22 states that the purpose of the standby diesel generator engine system is to provide standby power for the operation of ESFs and emergency systems during and

following a reactor shutdown when offsite power is not available. The standby diesel generator engine system contains the diesel generator cooling water system, starting system, lubrication system, and combustion air intake and exhaust system.

The intended functions of the standby diesel generator engine system within the scope of license renewal include the following:

- to provide onsite emergency power for equipment that supports the safe shutdown of the reactor and maintains it in a safe shutdown condition
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support fire protection (10 CFR 50.48), EQ (10 CFR 50.49), and SBO (10 CFR 50.63) requirements

LRA Table 2.3.3-22 identifies the standby diesel generator engine system component types within the scope of license renewal and subject to an AMR.

2.3.3.22.1 Staff Evaluation

The staff reviewed LRA Section 2.3.3.22, FSAR Sections 8.3.1.1.3 SP, 9.5.5 SP, 9.5.6 SP, 9.5.7 SP, and 9.5.8 SP 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.

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

The staff noted license renewal boundary drawings LR-CW-M-22KJ02 and LR-CW-M-22KJ05, locations F-8 and H-8, depict turbocharger casings as being within the scope of license renewal for 10 CFR 54.4(a)(1). However, the turbocharger casing is not listed in LRA Table 2.3.3-22 as a component type subject to an AMR. By letter dated June 11, 2012, the staff issued RAI 2.3.3.22-1 requesting the applicant to justify the exclusion of the turbocharger casing as a component type from LRA Table 2.3.3-22.

In its response letter dated July 2, 2012, the applicant stated that the component type "turbocharger casing" has been added to LRA Table 2.3.3-22 with an intended function of "pressure boundary." The applicant also provided a revision of LRA Table 2.3.3-22 as part of its response.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.22-1 acceptable because the component type "turbocharger casing" was added to LRA Table 2.3.3-22 and is therefore subject to an AMR as required by 10 CFR 54.21(a)(1). The staff's concern described in RAI 2.3.3.22-1 is resolved.

The staff noted license renewal boundary drawings LR-CW-M-22KJ02 and LR-CW-M-22KJ05, location G-7, depict an air pressure supply manifold housings as being within the scope of license renewal for 10 CFR 54.4(a)(1). However, the air pressure supply manifold housing is not listed in LRA Table 2.3.3-22 as a component type subject to an AMR. By letter dated June 11, 2012, the staff issued RAI 2.3.3.22-2 requesting the applicant to justify the exclusion of the air supply manifold housing as a component type from LRA Table 2.3.3-22.

In its response letter dated July 2, 2012, the applicant stated that the air pressure supply manifold housings were evaluated as component type "piping," with an intended function of "pressure boundary" in LRA Table 2.3.3-22.

Based on its review, the staff finds the applicant's response to RAI 2.3.22-2 acceptable because the air pressure supply manifold housings were evaluated as component type "piping" in LRA Table 2.3.3-22 and are therefore subject to an AMR as required by 10 CFR 54.21(a)(1). The staff's concern described in RAI 2.3.3.22-2 is resolved.

The staff noted license renewal boundary drawings LR-CW-M-22KJ02 and LR-CW-M-22KJ05, locations A-6 and C-6, depict pulsation dampers as being within the scope of license renewal for 10 CFR 54.4(a)(2). However, the pulsation damper is not listed in LRA Table 2.3.3-22 as a component type subject to an AMR. By letter dated June 11, 2012, the staff issued RAI 2.3.3.22-3 requesting the applicant to justify the exclusion of the pulsation damper as a component type from LRA Table 2.3.3-22.

In its response letter dated July 2, 2012, the applicant stated that the pulsation dampers were evaluated as component type "tank" with intended functions of "leakage boundary (spatial)" and "structural integrity (attached)" in LRA Table 2.3.3-22.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.22-3 acceptable because the pulsation dampers were evaluated as component type "tank" in LRA Table 2.3.3-22 and are therefore subject to an AMR as required by 10 CFR 54.21(a)(1). The staff's concern described in RAI 2.3.3.22-3 is resolved.

The staff noted license renewal boundary drawings LR-CW-M-22KJ03 and LR-CW-M-22KJ06, location F-4, depict lube oil ejector casings as being within the scope of license renewal for 10 CFR 54.4(a)(1). However, the lube oil ejector casing is not listed in LRA Table 2.3.3-22 as a component type subject to an AMR. By letter dated June 11, 2012, the staff issued RAI 2.3.3.22-4 requesting the applicant to justify the exclusion of the lube oil ejector casing as a component type from LRA Table 2.3.3-22.

In its response letter dated July 2, 2012, the applicant stated that the lube oil ejector casings were evaluated as component type "pump" with an intended function of "pressure boundary" in LRA Table 2.3.3-22.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.22-4 acceptable because the lube oil ejector casings were evaluated as component type "pump" in LRA Table 2.3.3-22 and are therefore subject to an AMR as required by 10 CFR 54.21(a)(1). The staff's concern described in RAI 2.3.3.22-4 is resolved.

The staff noted license renewal boundary drawings LR-CW-M-22KJ03 and LR-CW-M-22KJ06, location F-5, depict oil separator casings as being within the scope of license renewal for 10 CFR 54.4 (a)(1). However, the oil separator casing is not listed in LRA Table 2.3.3-22 as a component type subject to an AMR. By letter dated June 11, 2012, the staff issued RAI 2.3.3.22-5 requesting the applicant to justify the exclusion of the oil separator casing as a component type from LRA Table 2.3.3-22.

In its response letter dated July 2, 2012, the applicant stated that the oil separator casings were evaluated as component type "filter" with an intended function of "pressure boundary" in LRA Table 2.3.3-22.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.22-5 acceptable because the oil separator casings were evaluated as component type "filter" in LRA Table 2.3.3-22 and is therefore subject to an AMR as required by 10 CFR 54.21(a)(1). The staff's concern described in RAI 2.3.3.22-5 is resolved.

The staff noted license renewal boundary drawings LR-CW-M-22KJ02 and LR-CW-M-22KJ05, location G-3, depict four "XJ" components as being within the scope of license renewal for 10 CFR 54.4(a)(1). However, the staff could not identify or review the components due to a lack of information of what these components are, what intended function(s) they perform, and if they are listed in LRA Table 2.3.3-22 as component types subject to an AMR. By letter dated June 11, 2012, the staff issued RAI 2.3.3.22-6 requesting the applicant to identify the "XJ" components and their intended functions, and to identify if they were included as component types in LRA Table 2.3.3-22.

In its response dated July 2, 2012, the applicant stated that the "XJ" components were evaluated as component type "expansion joint" with an intended function of "pressure boundary" in LRA Table 2.3.3-22.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.22-6 acceptable because the "XJ" components were evaluated as component type "expansion joint" in LRA Table 2.3.3-22 and are therefore subject to an AMR as required by 10 CFR 54.21(a)(1). The staff's concern described in RAI 2.3.3.22-6 is resolved.

2.3.3.22.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, FSAR, RAI responses, and license renewal boundary drawings, the staff concludes that the applicant has appropriately identified the standby diesel generator engine system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.23 EOF and TSC Diesels, Security Building System

2.3.3.23.1 Summary of Technical Information in the Application

LRA Section 2.3.3.23 states that the purpose of the emergency operations facility (EOF) and technical support center (TSC) diesels, security building system is to provide backup power to the EOF, TSC, security building, and mechanical equipment supporting nonsafety-related buildings.

The intended function of the EOF and TSC diesels, security building system within the scope of license renewal is to support SBO (10 CFR 50.63) requirements.

LRA Table 2.3.3-23 identifies the EOF and TSC diesels, security building system component types within the scope of license renewal and subject to an AMR.

2.3.3.23.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.23 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. On the basis of its review, the staff did not identify the need for any additional information.

2.3.3.23.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3, and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the EOF and TSC diesels, security building system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.24 Liquid Radwaste System

2.3.3.24.1 Summary of Technical Information in the Application

LRA Section 2.3.3.24 states that the purpose of the liquid radwaste system is to collect, segregate, process, and recycle liquid wastes during plant power, refueling, and maintenance operations. The liquid radwaste system handles potentially radioactive floor and equipment drains, laundry, and chemical waste.

The intended functions of the liquid radwaste system within the scope of license renewal include the following:

- to minimize the release of fission products following a loss of coolant or fuel handling accident
- to provide part of the safety-related pressure boundary of the CCW system
- to provide containment isolation
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support EQ (10 CFR 50.49) requirements

LRA Table 2.3.3-24 identifies the liquid radwaste system component types within the scope of license renewal and subject to an AMR.

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. On the basis of its review, the staff 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 SER Section 2.3 and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant has appropriately identified the liquid radwaste system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes 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 Decontamination System

2.3.3.25.1 Summary of Technical Information in the Application

LRA Section 2.3.3.25 states that the purpose of the decontamination system is to provide for cleaning of contaminated equipment and clothing at the plant. Through a containment penetration, the decontamination system introduces steam into the containment for the decontamination of areas of the refueling pool and reactor vessel head located within the containment. In addition, the decontamination system provides for the decontamination of spent fuel shipping casks.

The intended functions of the decontamination system within the scope of license renewal include the following:

- to provide containment integrity
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support EQ (10 CFR 50.49) requirements

LRA Table 2.3.3-25 identifies the decontamination system component types within the scope of license renewal and subject to an AMR.

2.3.3.25.2 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. On the basis of its review, the staff 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 SER Section 2.3 and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant has appropriately identified the decontamination system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes 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 Oily Waste System

2.3.3.26.1 Summary of Technical Information in the Application

LRA Section 2.3.3.26 states that the purpose of the oily waste system is to collect, process, and dispose of nonradioactive waste water from areas that may contain oil and to collect, process, and recycle waste water that may contain oil or radioactive contaminants.

The intended functions of the oily waste system within the scope of license renewal are: (1) to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2), and (2) to support fire protection (10 CFR 50.48) requirements.

LRA Table 2.3.3-26 identifies the oily waste system component types within the scope of license renewal and subject to an AMR.

2.3.3.26.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.26 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. On the basis of its review, the staff did not identify the need for any additional information.

2.3.3.26.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant has appropriately identified the oily waste system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.27 Floor and Equipment Drainage System

2.3.3.27.1 Summary of Technical Information in the Application

LRA Section 2.3.3.27 states that the purpose of the floor and equipment drainage system is to collect, monitor, properly direct, process, and dispose of liquid waste generated within the plant. The floor and equipment drainage system also contains and drains away any leakage of RCP lubricating oil.

The intended functions of the floor and equipment drainage system within the scope of license renewal include the following:

- to support the functions of containment integrity and the maintenance of vital auxiliary SCs
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support fire protection (10 CFR 50.48) and EQ (10 CFR 50.49) requirements

LRA Table 2.3.3-27 identifies the floor and equipment drainage system component types within the scope of license renewal and subject to an AMR.

2.3.3.27.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.27, FSAR Sections 6.2.4 SP, 9.3.3 SP, and 9.5.1 SP 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. On the basis of its review, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results.

The staff noted license renewal boundary drawing LR-CW-LF-M-22LF01, location H-4, depicts A10-XND-"4" piping within the scope of license renewal for 10 CFR 54.4(a)(2). However, the continuation from license renewal boundary drawing LR-CW-LF-M-22LF02, location A-4, depicts the piping within the scope of license renewal for 10 CFR 54.4(a)(3).

By letter dated June 11, 2012, the staff issued RAI 2.3.3.27-1 requesting the applicant to clarify the scoping classification of the A10-XND-4" piping.

In its response letter dated July 2, 2012, the applicant stated the continuation of the A10-XND-"4" piping onto license renewal boundary drawing LR-CW-LR- M-22LF01 was incorrectly depicted as being within the scope of license renewal for 10 CFR 54.4(a)(2). The applicant also indicated that the A10-XND-"4" piping depicted on license renewal boundary drawing LR-CW-LR-M-22LF01 should be within the scope of license renewal for 10 CFR 54.4(a)(3). The applicant revised the license renewal boundary drawing LR-CW-LR-M-22LF01 to depict the A10-XND-"4" piping within the scope of license renewal for 10 CFR 54.4(a)(3).

Based on its review, the staff finds the applicant's response to RAI 2.3.3.27-1 acceptable because the applicant clarified the scoping classification of the A10-XND-"4" piping as being within the scope of license renewal for 10 CFR 54.4(a)(3). The staff reviewed license renewal boundary drawing LR-CW-LR- M-22LF01 to confirm that the A10-XND-"4" piping scoping classification was revised to 10 CFR 54.4(a)(3). Therefore, the staff's concern described in RAI 2.3.3.27-1 is resolved.

2.3.3.27.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3, and on a review of the LRA, FSAR, RAI response, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the floor and equipment drainage system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.28 Miscellaneous Systems In Scope ONLY for Criterion 10 CFR 54.4(a)(2)

2.3.3.28.1 Summary of Technical Information in the Application

LRA Section 2.3.3.28 states that the following systems were identified as within the scope of license renewal only because portions of them consist of nonsafety-related components affecting safety-related components based on 10 CFR 54.4(a)(2) criteria:

- condensate system
- demineralized water makeup system
- condensate and feedwater chemical addition system
- plant heating system
- central chilled water system
- gaseous radwaste system
- solid radwaste system
- boron recycle system
- secondary liquid waste system
- domestic water system
- sanitary drainage system
- roof drains system
- chemical and detergent waste system

Condensate System. LRA Section 2.3.3.28 states that the purposes of the condensate system are the following:

- to provide a heat sink for the steam cycle
- to provide a surge volume and flow collection points for the steam
- to provide for removal of air and non-condensable gasses
- to provide a source of water to the main feedwater pumps
- to provide hood sprays to the turbine exhaust
- to provide cooling to the steam generator blowdown regenerative heat exchanger
- to provide seal water to the condensate and turbine-driven main feedwater pumps
- to accept and bypass steam flow to the main condenser

Demineralized Water Makeup System. LRA Section 2.3.3.28 states that the purpose of the demineralized water makeup and transfer system is to store water for makeup use and to transfer water to diverse components.

Condensate and Feedwater Chemical Addition System. LRA Section 2.3.3.28 states that the purpose of the condensate and feedwater chemical addition system is to inject hydrazine and ammonia or an alternate amine into the condensate pump discharge and to inject additional hydrazine and ammonia into the steam generators main feedwater lines.

Plant Heating System. LRA Section 2.3.3.28 states that the purpose of the plant heating system is to provide a medium for heating air to maintain a suitable environment for personnel and equipment.

Central Chilled Water System. LRA Section 2.3.3.28 states that the purpose of the central chilled water system is to provide a medium for cooling, when required, equipment and ventilation system cooling coils.

Gaseous Radwaste System. LRA Section 2.3.3.28 states that the purpose of the gaseous radwaste system is to receive and contain fission gases removed from radioactive fluids to eliminate the need for regular discharge to the atmosphere of radioactive gases during normal plant operation. The gaseous radwaste system has the capacity to provide long-term storage for fission gases.

Solid Radwaste System. LRA Section 2.3.3.28 states that the purpose of the solid radwaste system is to collect, process, and package normal plant operation and anticipated operational occurrences radioactive wastes. The solid radwaste system stores the packaged radioactive wastes until it is shipped off site to a licensed burial site.

Boron Recycle System. LRA Section 2.3.3.28 states that the purpose of the boron recycle system is to support the reuse of boric acid and makeup water by means of recycling reactor coolant. The boron recycle system uses demineralization and gas stripping to decontaminate the effluent; evaporation is also used to separate and recover the boric acid and makeup water.

Secondary Liquid Waste System. LRA Section 2.3.3.28 states that the purpose of the secondary liquid waste system is to process wastes collected in the turbine building (e.g., condensate demineralizer regeneration waste and potentially radioactive liquid waste).

Domestic Water System. LRA Section 2.3.3.28 states that the purpose of the domestic water system is “to distribute and heat chlorinated potable water for drinking, cooking, showers, lavatories, toilets, and washdown.”

Sanitary Drainage System. LRA Section 2.3.3.28 states that the purpose of the sanitary drainage system is to collect non-corrosive, non-radioactive, non-oily liquid wastes and sewage within the non-radioactive areas of the power block from service and pantry facilities; electric water coolers and heaters, clean showers, plumbing fixtures, and toilet room floor drains.

Roof Drains System. LRA Section 2.3.3.28 states that the purpose of the roof drains system is to collect precipitation water from building roofs and convey the water by gravity to the storm drain system.

Chemical and Detergent Waste System. LRA Section 2.3.3.28 states that the purpose of the chemical and detergent waste system is "to collect waste from selected laboratory sinks and washers, recycle evaporator and reagent tank, waste evaporator and reagent tank, secondary liquid waste evaporator and reagent tank, radwaste building sample panel, evaporator bottoms tank overflow, decon showers, and men's showers."

LRA Table 2.3.3-28 identifies the "Miscellaneous Systems In Scope ONLY for Criterion 10 CFR 54.4(a)(2)" component types within the scope of license renewal and subject to an AMR.

2.3.3.28.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.28 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. On the basis of its review, the staff did not identify the need for any additional information.

2.3.3.28.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3, and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the "Miscellaneous Systems In Scope ONLY for Criterion 10 CFR 54.4(a)(2)" components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.29 Circulating Water System

2.3.3.29.1 Summary of Technical Information in the Application

In a letter dated February 14, 2014, the applicant submitted LRA Section 2.3.3.29 as part of LRA Amendment 31. The amendment states that the circulating water system was added to the scope of license renewal as a result of the issuance of Callaway license Amendment 206, regarding transition to a risk-informed, performance-based fire protection program in accordance with 10 CFR 50.48(c), "National Fire Protection Association Standard NFPA 805." The applicant stated that the circulating water system was added to support fire protection requirements based upon the criteria of 10 CFR 54.4(a)(3). The applicant stated that the system provides a return path to the cooling tower for the service water system consistent with NFPA 805 changes. The applicant also stated that the purpose of the circulating water system is to supply cooling water from the plant's cooling water source to the main condenser to condense discharged steam from the exhaust of the turbine or the turbine bypass system. Finally, LRA Section 2.3.3.29 states that the system is nonsafety-related and performs no safety-related functions.

The intended function of the circulating water system portion within the scope of license renewal is to support fire protection requirements of 10 CFR 50.48 and NFPA 805, based upon the criteria of 10 CFR 54.4(a)(3).

2.3.3.29.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.29 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. On the basis of its review, the staff did not identify the need for any additional information.

2.3.3.29.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3, and on a review of the LRA, LRA Amendment 31, FSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the circulating water system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4 Steam and Power Conversion Systems

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

- LRA Section 2.3.4.1, “Main Turbine System”
- LRA Section 2.3.4.2, “Main Steam Supply System”
- LRA Section 2.3.4.3, “Main Feedwater System”
- LRA Section 2.3.4.4, “Steam Generator Blowdown System”
- LRA Section 2.3.4.5, “Auxiliary Feedwater System”
- LRA Section 2.3.4.6, “Condensate Storage and Transfer System”

Steam and Power Conversion Generic Request for Additional Information

The staff noted the following instances on license renewal boundary drawings where the continuation of in-scope piping could not be identified:

- “F”-HBD-2” and “I”-HBD-2” piping on license renewal boundary drawing LR-CW-AB-M-22AB02, location B-6
- piping downstream of valves V039m, V028, V017, and V006, which continues from license renewal boundary drawing LR-CW-BM-M-22BM01, locations B-5, C-5, E-5, and G-5 respectively, to license renewal boundary drawing M-22RM01, which was not provided in the LRA
- piping downstream of valve V998 on license renewal boundary drawing LR-CW-AL-M-22FC02

By letter dated June 11, 2012, the staff issued RAI 2.3.4-1 requesting the applicant to identify the continuation and termination of the above piping examples, along with any information regarding scoping classification changes as necessary.

In its response letter dated July 2, 2012, the applicant provided information to clarify the above piping continuation examples as follows:

- On license renewal boundary drawing LR-CW-AB-M-22AB02, the applicant stated that pipe sections "I"-HBD-2" and "F"-HBD-3/4" continue and connect with their respective lines "E"-HBD-2" and "A"-HBD-1" for each of the safety valves in their loop. The applicant included a note in the revised license renewal boundary drawing LR-CW-AB-M-22AB02 to clarify the scoping boundary for the pipe sections. The staff confirmed that the applicant corrected the pipe sections as part of its RAI response. The staff also reviewed the revised license renewal boundary drawing LR-CW-AB-M-22AB02 to confirm the scoping boundary for the above pipe sections and the inclusion of the note.
- On license renewal boundary drawing LR-CW-BM-M-22BM01, the applicant stated that each of the continuation piping downstream of valves V039, V028, V017, and V006 is tubing. The applicant indicated that the valves are within the scope of license renewal for 10 CFR 54.4 (a)(2) with an intended function of structural integrity (attached). The applicant stated that the tubing attached downstream of these valves does not have an intended function of structural integrity (attached). The applicant also included a note to the revised license renewal boundary drawing LR-CW-BM-M-22BM01 to indicate that tubing is not within the scope of license renewal.
- On license renewal boundary drawing LR-CW-AL-M-22FC02, the applicant stated that valve 998 is a sentinel relief valve that vents directly to the room and no further continuation is needed. The applicant also included a note to the revised license renewal boundary drawing LR-CW-AL-M-22FC02 to indicate the scoping boundary for the sentinel relief valve.

Based on its review, the staff finds the applicant's response to RAI 2.3.4-1 acceptable because the applicant clarified each of the continuation piping examples as described above and identified the system scoping boundary in each instance. The staff reviewed the above revised license renewal boundary drawings to confirm the scoping boundaries as described in the applicant's RAI response. Therefore, the staff's concern described in RAI 2.3.4-1 is resolved.

2.3.4.1 Main Turbine System

2.3.4.1.1 Summary of Technical Information in the Application

LRA Section 2.3.4.1 states that the purpose of the main turbine system is to convert the steam thermal energy to mechanical energy to drive the main generator.

The intended function of the main turbine system within the scope of license renewal is to support ATWS (10 CFR 50.62) requirements.

LRA Table 2.3.4-1 identifies the main turbine system component types within the scope of license renewal and subject to an AMR.

2.3.4.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.1 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. On the basis of its review, the staff did not identify the need for any additional information.

2.3.4.1.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the main turbine system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.2 Main Steam Supply System

2.3.4.2.1 Summary of Technical Information in the Application

LRA Section 2.3.4.2 states that the purpose of the main steam supply system is to send the steam produced in the steam generators to the turbine generator, turbine driven feedwater pumps, the turbine-driven auxiliary feed pump, steam dumps, reheaters, and the auxiliary steam system.

The intended functions of the main steam supply system within the scope of license renewal include the following:

- to provide heat removal from the RCS for controlled cooldown during normal, accident, and post-accident conditions
- to provide containment isolation and overpressure protection for the steam generator secondary side and the main steam piping
- to provide steam to support the operation of the turbine-driven auxiliary feedwater pump
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support fire protection (10 CFR 50.48), SBO (10 CFR 50.63), and EQ (10 CFR 50.49) requirements

LRA Table 2.3.4-2 identifies the main steam supply system component types within the scope of license renewal and subject to an AMR.

2.3.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.2, FSAR Sections 10.3 SP and 10.4 SP 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. On the basis of its review, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results.

The staff noted license renewal boundary drawing LR-CW-AE-M-22AB02 depicts main steam piping in the auxiliary building highlighted in green, which indicates that the piping is within the scope of license renewal for 10 CFR 54.4(a)(1). However, at locations C-2, D-2, F-2, and G-2, four sections of main steam piping exit the auxiliary building and continue into the turbine building. As described by Note 1 on license renewal boundary drawing LR-CW-AE-M-22AB02, the scoping classification change and seismic portion of the main steam piping occurs at the first weld within the turbine building. Nonsafety-related components were not identified within the scope of license renewal for 10 CFR 54.4(a)(2)

inside the turbine building on the license renewal boundary drawing, as required by the applicant's scoping methodology described in LRA Section 2.1.2.2. By letter dated June 11, 2012, the staff issued RAI 2.3.4.2-1 requesting the applicant to provide justification for excluding the nonsafety-related components in the turbine building, which may be in proximity of the 10 CFR 54.4(a)(1) main steam piping, from the scope of license renewal for 10 CFR 54.4(a)(2).

In its response letter dated July 2, 2012, the applicant stated that the main steam piping located in the turbine building is not relied upon to remain functional during or following DBEs and is excluded from scope of license renewal for 10 CFR 54.4(a)(1). The applicant explained that the Callaway FSAR defines the portion of the main steam piping from the containment penetration to outside the outboard isolation restraint as a "no break zone." The outboard isolation restraint is a torsional restraint in the wall between the auxiliary building and the turbine building. The applicant also indicated that Callaway FSAR Section 3.6.2.1.1e states that stresses within the "no break zone" will remain acceptable when subjected to the combined loadings of internal pressure, dead weight, and postulated pipe break beyond the "no break zone." The applicant further stated that the main feedwater and steam generator blowdown systems also have safety classification breaks in the turbine building.

As with the main steam piping, the applicant also determined that the piping for these systems inside the turbine building are not within the scope of license renewal for 10 CFR 54.4(a)(1). The applicant stated that plant documentation associated with these sections of piping was being revised to clarify the safety classification boundary as being at the wall between the auxiliary building and the turbine building.

Based on its review, the staff found the applicant's response to RAI 2.3.4.2-1 unacceptable. Therefore, by letter dated October 12, 2012, the staff issued RAI 2.3.4.2-1a requesting the applicant to provide its justification for excluding from the scope of license renewal the attached main steam piping, which extends from the "no break zone" area and into the turbine building. In addition, during a telephone conference call with the applicant held on December 6, 2012, the staff stated that the applicant needs to provide clarification of the safety classification boundaries of the piping for the main steam, main feedwater, and steam generator blowdown systems, which exit the auxiliary building and enter the turbine building. During the telephone conference call, the staff also stated that it considers the applicant's intention to exclude the attached nonsafety-related piping in the turbine building for the main steam, main feedwater, and steam generator blowdown systems an exception to its 10 CFR 54.4(a)(2) scoping methodology for attached nonsafety-related piping to safety-related piping as described in LRA Section 2.1.2.2. During the telephone conference call, the applicant stated that it will address the staff's concerns in its upcoming response to RAI 2.3.4.2-1a.

By letter dated January 10, 2013, the applicant provided its response to RAI 2.3.4.2-1a. In its response, the applicant indicated that the piping for the main steam and main feedwater systems are located in "no break zones," which extend from the anchors in the reactor building wall to outside the torsional restraints in the auxiliary building to turbine building wall. The applicant defined "no break zones" as areas of high energy piping, where breaks are not postulated because the stresses are limited. The applicant also further described the "no break zones" in the RAI response as not exceeding the "1.8 S_h per equation (9), Subarticle NC-3652 of ASME Section III when subjected to the combined loadings of internal pressure, deadweight, and postulated pipe break beyond the no break zone." The applicant's safety assessment of the safety-related piping for the main steam and main feedwater systems concluded that, since this piping is located in the "no break zones," postulated pipe breaks on the turbine building side

beyond the “no break zones” would not prevent the piping within the “no break zones” from performing its intended functions. The applicant excluded the nonsafety-related piping, which is attached to the safety-related piping for the main steam and main feedwater systems, in the turbine building because the failure of this piping beyond the “no break zones” will not prevent the connected safety-related components from performing their intended function.

Also, as part of its response, the applicant stated that Callaway was taking an exception to NEI 95-10, Appendix F, to exclude the nonsafety-related piping attached to the safety-related piping of the main steam and main feedwater systems beyond the “no break zones” and into the turbine building from the scope of license renewal. The applicant revised LRA Section 2.1.2.2 to provide the justification for taking this exception to NEI 95-10, Appendix F. The applicant indicated in its response that the steam generator blowdown system will continue to meet NEI 95-10, Appendix F. The applicant included the revised license renewal boundary drawing LR-CW-BM-22BM01 for the steam generator blowdown system to depict that the nonsafety-related piping was included within the scope of license renewal for 10 CFR 54.4(a)(2). The applicant also provided supplemental drawings of the “no break zones” and torisional restraints located within the “no break zones” for staff review. In addition, the applicant revised LRA Section 2.3.4.3 and Table 3.4.2-3 as part of its RAI response to remove the nonsafety-related main feedwater system components in the turbine building from the scope of license renewal. The applicant deleted and revised license renewal boundary drawings, LR-CW-AE-M-22AE01 and LR-CW-AE-M-22AE02 respectively, to remove the red highlighted nonsafety-related components in the turbine building from scope of license renewal.

The staff reviewed the applicant’s FSAR assessment, RAI response, and supplemental plant drawings of the “no break zones” and torsional restraints for the main steam and main feedwater systems. Based on its review, the staff finds that the torsional restraint consists of two sets of restraints about 8 ft (2.4 m) apart, which act as bending moment restraints and torsional moment restraints along with lateral guides. The staff observed that the axial restraining effect is provided by the containment anchor because of the straight sections of main steam and main feedwater safety piping between the containment anchor and the auxiliary building wall within the “no break zone.” The staff finds that the safety-related piping in the “no break zones” is protected from pipe break effects outside of auxiliary building wall. Therefore, the staff finds the applicant’s justification for taking exception to NEI 95-10, Appendix F acceptable because (1) the physical design of the “no break zone” does not allow any piping failures downstream from the auxiliary building wall to impact the safety-related main steam and main feedwater piping in the “no break zones,” and (2) the physical layout of the main steam and main feedwater piping from the containment anchor to the auxiliary building wall restrains any axial movement of the piping beyond the “no break zones.” The staff finds the applicant’s response to RAI 2.3.4.2-1a acceptable because the applicant provided an adequate justification for excluding from the scope of license renewal the main steam piping which extends from the "no break zone" area into the turbine building.

The staff also reviewed the revised LRA Sections 2.1.2.2, 2.3.4.3, and the license renewal boundary drawings for the main steam and main feedwater systems to confirm that the nonsafety-related piping in the turbine building was removed from scope of license renewal. The staff also reviewed the revised license renewal boundary drawing for the steam generator blowdown system to confirm that the nonsafety-related piping was included within the scope of license renewal for 10 CFR 54.4(a)(2). Therefore, the staff’s concerns described in RAI 2.3.4.2-1 and RAI 2.3.4.2-1a are resolved.

2.3.4.2.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, FSAR, RAI responses, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the main steam supply system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.3 Main Feedwater System

2.3.4.3.1 Summary of Technical Information in the Application

LRA Section 2.3.4.3 states that the purpose of the main feedwater system is to receive condensate from the condensate system and deliver feedwater to the four steam generators at the required pressure, temperature, and flow rate.

The intended functions of the main feedwater system within the scope of license renewal include the following:

- to provide containment and feedwater isolation for reactivity control during an accident
- to provide a flow path for auxiliary feedwater for the removal of decay heat
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support fire protection (10 CFR 50.48), EQ (10 CFR 50.49), ATWS (10 CFR 50.62), and SBO (10 CFR 50.63) requirements

LRA Table 2.3.4-3 identifies the main feedwater system component types within the scope of license renewal and subject to an AMR.

2.3.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.3, FSAR Section 10.4.7 SP, 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. On the basis of its review, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results.

The staff noted license renewal boundary drawing LR-CW-AE-M-22AE01 depicts solenoid valves, which are highlighted in green, at locations A-7, B-7, C-7, D-7, E-7, F-7, G-7, and H-7. These solenoid valves are accompanied on the license renewal boundary drawing with license renewal Note 1, which indicates that these valves are within the scope of license renewal under 10 CFR 54.4(a)(1). However, there were not any nonsafety-related components identified on license renewal boundary drawing LR-CW-AE-M-22AE01. The exclusion of these nonsafety-related components from the scope of license renewal appears to be inconsistent with the scoping methodology described in LRA Section 2.1.2.2. By letter dated June 11, 2012, the staff issued RAI 2.3.4.3-1 requesting the applicant to provide justification for excluding the nonsafety-related components near the solenoid valves from the scope of license renewal for 10 CFR 54.4(a)(2) on license renewal boundary drawing LR-CW-AE-M-22AE01.

In its response letter dated July 2, 2012, the applicant stated that the solenoid valves do not have a safety-related intended function consistent with the 10 CFR 54.4(a)(1) criteria, and were incorrectly identified on the boundary drawing as being within the scope of license renewal for 10 CFR 54.4(a)(1). The applicant did further state that the solenoid valves are within the scope of license renewal for 10 CFR 54.4(a)(2) because they support the diverse backup function of the main feedwater control valves and main feedwater bypass control valves. The applicant revised license renewal boundary drawing LR-CW-AE-M-22AE01 to depict the solenoid 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 2.3.4.3-1 acceptable because the solenoid valves do not have a safety-related intended function consistent with 10 CFR 54.4(a)(1). The staff reviewed reference documents regarding the initial classification of the solenoid valves during the April 16–19, 2012 scoping and screening audit, which support the applicant's RAI response. However, the safety-related classification of the solenoid valves in the current LRA was not identified by the applicant before the staff's initial review. The staff also finds the applicant's scoping classification of the solenoid valves as being within the scope of license renewal for 10 CFR 54.4(a)(2) acceptable since the solenoid valves support the safety functions of main feedwater control valves and main feedwater bypass control valves. The staff reviewed the revised license renewal boundary drawing LR-CW-AE-M-22AE01 to confirm that the solenoid valves are shown as being within the scope of license renewal for 10 CFR 54.4(a)(2). Therefore, the staff's concern described in RAI 2.3.4.3-1 is resolved.

Also, in its January 10, 2013, response to RAI 2.3.4.2-1a, the applicant stated that Callaway was taking an exception to NEI 95-10, Appendix F, to exclude the nonsafety-related piping attached to the safety-related piping of the main feedwater systems beyond the "no break zones" and into the turbine building from the scope of license renewal. As part of its response, the applicant revised LRA Section 2.1.2.2 to provide the justification for taking this exception to NEI 95-10, Appendix F. The staff's resolution of this issue is documented in SER Section 2.3.4.2.

2.3.4.3.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, FSAR, RAI response, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the main feedwater system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.4 Steam Generator Blowdown System

2.3.4.4.1 Summary of Technical Information in the Application

LRA Section 2.3.4.4 states that the purpose of the steam generator blowdown system is to maintain the secondary side water of the steam generators within the chemical specifications.

The intended functions of the steam generator blowdown system within the scope of license renewal include the following:

- to provide containment isolation for four containment penetrations with isolation valves inside and outside of containment

- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support fire protection (10 CFR 50.48), EQ (10 CFR 50.49), and ATWS (10 CFR 50.62) requirements

LRA Table 2.3.4-4 identifies the steam generator blowdown system component types within the scope of license renewal and subject to an AMR.

2.3.4.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.4 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. On the basis of its review, the staff did not identify the need for any additional information.

2.3.4.4.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the steam generator blowdown system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.5 Auxiliary Feedwater System

2.3.4.5.1 Summary of Technical Information in the Application

LRA Section 2.3.4.5 states that the purpose of the auxiliary feedwater system is to provide feedwater to the steam generators during startup, shutdown, and emergency conditions.

The intended functions of the auxiliary feedwater system within the scope of license renewal include the following:

- to provide decay heat removal in post-accident conditions
- to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to support fire protection (10 CFR 50.48), EQ (10 CFR 50.49), ATWS (10 CFR 50.62), and SBO (10 CFR 50.63) requirements

LRA Table 2.3.4-5 identifies the auxiliary feedwater system component types within the scope of license renewal and subject to an AMR.

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. On the basis of its review, the staff 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 SER Section 2.3 and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the auxiliary feedwater system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.6 Condensate Storage and Transfer System

2.3.4.6.1 Summary of Technical Information in the Application

LRA Section 2.3.3.4.6 states that the purpose of the condensate storage and transfer system is to deliver or receive condensate to compensate for changes in plant systems inventory. The condensate storage and transfer system consists of a 450,000-gallon condensate storage tank that works as a non-seismically designed source of water to the auxiliary feedwater system. The condensate storage and transfer system is not credited for accident mitigation.

The intended functions of the condensate storage and transfer system within the scope of license renewal are: (1) to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2); and (2) to support fire protection (10 CFR 50.48), EQ (10 CFR 50.49), and SBO (10 CFR 50.63) requirements.

LRA Table 2.3.4-6 identifies the condensate storage and transfer system component types within the scope of license renewal and subject to an AMR.

2.3.4.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.6 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. On the basis of its review, the staff did not identify the need for any additional information.

2.3.4.6.3 Conclusion

Based on the results of the staff evaluation discussed in SER Section 2.3 and on a review of the LRA, FSAR, and license renewal boundary drawings, the staff concludes that the applicant appropriately identified the condensate storage and transfer system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also concludes that the applicant adequately identified the system components subject to an AMR, in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4 Scoping and Screening Results: Structures

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

- reactor building
- control building
- auxiliary building
- turbine building

- diesel generator building
- miscellaneous in-scope structures
- in-scope tank foundations and structures
- electrical foundations and structures
- radwaste building
- fuel building
- ESW structures
- supports

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

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

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

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

2.4.1 Reactor Building

2.4.1.1 Summary of Technical Information in the Application

In LRA Section 2.4.1, the applicant described the reactor building as including internal structural components within the scope of license renewal that are safety-related, in accordance with 10 CFR 54.4(a)(1). Portions of the reactor building provide structural support, shelter, and protection for nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of a safety-related function, in accordance with 10 CFR 54.4(a)(2).

The reactor building is a seismic Category I structure, which provides protection for the reactor vessel, RCS, steam generators, pressurizer, RCPs, accumulators, and containment air coolers. The staff defines seismic Category I structures as SSCs designed and built to withstand the maximum potential earthquake stresses for the particular region where a nuclear plant is sited.

The building is a pre-stressed and conventionally reinforced concrete structure consisting of several major structural components, including a steel liner plate, penetrations, and various reactor building internal structures.

Reactor building internal structures include a heavily reinforced concrete reactor cavity that houses the reactor and provides the primary shield barrier, secondary shield walls, and the refueling canal, a reinforced concrete structure lined with stainless steel used to transfer fuel elements under water between the reactor and the spent fuel pool. Structural steel provides support for various safety-related and nonsafety-related SCs, including piping, ducts, equipment, cable trays, conduit, instruments, and tubing.

The intended functions of the reactor building within the scope of license renewal include the following:

- to provide structural support and protection for safety-related SSCs required to mitigate the consequences of accidents that could result in potential offsite exposure
- to provide structural support and protect nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to provide structural support and protect SSCs that support fire protection (10 CFR 50.48), ATWS (10 CFR 50.62), and SBO (10 CFR 50.63), in accordance with the requirements stated in 10 CFR 54.4(a)(3)

LRA Table 2.4-1 identifies the reactor building component types within the scope of license renewal and subject to an AMR.

2.4.1.2 Staff Evaluation

The staff reviewed LRA Section 2.4.1 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. On the basis of its review, the staff did not identify the need for any additional information.

2.4.1.3 Conclusion

On the basis of its review of the LRA and FSAR, the staff concludes that the applicant has appropriately identified the reactor building 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).

2.4.2 Control Building

2.4.2.1 Summary of Technical Information in the Application

In LRA Section 2.4.2, the applicant described the control building as a seismic Category I structure supported by a reinforced concrete base mat founded on compacted soil. The

purpose of the control building is to support, shelter, and protect the main control room, access control areas, upper and lower cable spreading rooms, electrical and mechanical equipment rooms, Class 1E switchgear, battery rooms, and other equipment supporting the control room habitability systems. The intermediate floors and roof are reinforced concrete slabs supported by structural steel beams and girders while the floor and roof framing are supported by exterior reinforced concrete bearing walls and interior steel columns. The communications corridor adjacent to the control building is a non-Category I structure, which is designed to preclude gross collapse upon safety-related structures or components under loads imposed by the design-basis tornado.

The intended functions of the control building within the scope of license renewal include the following:

- to provide structural support and protection for safety-related SSCs required for safe shutdown of the reactor
- to provide structural support and protect nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to provide structural support and protect SSCs that support fire protection (10 CFR 50.48), ATWS (10 CFR 50.62), and SBO (10 CFR 50.63), in accordance with the requirements stated in 10 CFR 54.4(a)(3)

LRA Table 2.4-2 identifies the control building component types within the scope of license renewal and subject to an AMR.

2.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. On the basis of its review, the staff did not identify the need for any additional information.

2.4.2.3 Conclusion

On the basis of its review of the LRA and FSAR, the staff concludes that the applicant has appropriately identified the control building 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).

2.4.3 Auxiliary Building

2.4.3.1 Summary of Technical Information in the Application

In LRA Section 2.4.3, the applicant described the auxiliary building as a seismic Category I structure supported by a reinforced concrete base mat founded on compacted soil. The purpose of the auxiliary building is to support, shelter, and protect the safety injection system, RHR system, chemical and volume control monitoring system, auxiliary feedwater pumps, steam and feedwater isolation and relief valves, heat exchangers, other pumps, tanks, filters, demineralizers, and heating and ventilating equipment. The building also includes the non-Category I radioactive material storage building and laundry decontamination facility, whose

structural framing is designed to preclude gross collapse upon the auxiliary building or its components under loads imposed by the design-basis tornado.

The intended functions of the auxiliary building within the scope of license renewal include the following:

- to provide structural support and protection for safety-related SSCs required for safe shutdown of the reactor
- to provide structural support and protect nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to provide structural support and protect SSCs that support fire protection (10 CFR 50.48), ATWS (10 CFR 50.62), and SBO (10 CFR 50.63), in accordance with the requirements stated in 10 CFR 54.4(a)(3)

LRA Table 2.4-3 identifies the auxiliary building component types within the scope of license renewal and subject to an AMR.

2.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.4.3 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. On the basis of its review, the staff did not identify the need for any additional information.

2.4.3.3 Conclusion

On the basis of its review of the LRA and FSAR, the staff concludes that the applicant has appropriately identified the auxiliary building 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).

2.4.4 Turbine Building

2.4.4.1 Summary of Technical Information in the Application

In LRA Section 2.4.4, the applicant described the turbine building as a non-Category I building that is designed to support, shelter, and protect the turbine generator, condensers, main feed pumps, and other power conversion equipment; and houses the auxiliary boiler room, which is evaluated with the turbine building.

The intended functions of the turbine building within the scope of license renewal are: (1) to provide structural support and protect nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2) and (2) to provide structural support and protect SSCs that support fire protection (10 CFR 50.48) and ATWS (10 CFR 50.62), in accordance with the requirements stated in 10 CFR 54.4(a)(3).

LRA Table 2.4-4 identifies the turbine building component types within the scope of license renewal and subject to an AMR.

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. On the basis of its review, the staff did not identify the need for any additional information.

2.4.4.3 Conclusion

On the basis of its review of the LRA and FSAR, the staff concludes that the applicant has appropriately identified the turbine building 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).

2.4.5 Diesel Generator Building

2.4.5.1 Staff Evaluation Summary of Technical Information in the Application

In LRA Section 2.4.5, the applicant described the diesel generator building as a seismic Category I structure comprised of structural steel and reinforced concrete supported by a reinforced concrete base mat founded 10 ft below grade on crushed rock. The purpose of the building is to support, shelter, and protect the EDGs, diesel auxiliaries, emergency fuel oil day tanks, exhaust silencers, and exhaust stacks. A fire barrier wall separates the two standby diesel generator rooms. The building also includes fuel oil storage tanks, which consist of two buried cylindrical steel tanks and associated reinforced concrete access vaults.

The intended functions of the diesel generator building within the scope of license renewal include the following:

- to provide structural support and protection for safety-related SSCs required for safe shutdown of the reactor
- to provide structural support and protect nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to provide structural support and protect SSCs that support fire protection (10 CFR 50.48) and SBO (10 CFR 50.63), in accordance with the requirements stated in 10 CFR 54.4(a)(3)

LRA Table 2.4-5 identifies the diesel generator building component types within the scope of license renewal and subject to an AMR.

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. On the basis of its review, the staff did not identify the need for any additional information.

2.4.5.3 Conclusion

On the basis of its review of the LRA and FSAR, the staff concludes that the applicant has appropriately identified the diesel generator building 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).

2.4.6 Miscellaneous In-Scope Structures

2.4.6.1 Summary of Technical Information in the Application

In LRA Section 2.4.6, the applicant described the miscellaneous in-scope structures . The miscellaneous in-scope structures intended functions are to support, shelter, and protect equipment required for fire protection (10 CFR 50.48) and SBO (10 CFR 50.63) recovery. The miscellaneous in-scope structures include the following structures: fire pumphouse, security diesel generator building, security building (main access facility), switchyard control building, circulating and service water pumphouse, and the cooling tower basin:

Fire Pumphouse. A single-story metal-sided enclosure supported by structural steel framing on three sides and a concrete masonry block wall on the west face. The structure is supported by reinforced concrete footings on structural backfill and has interior block walls that serve as fire barriers. The roof consists of a built-up material over rigid insulation and metal deck supported by steel roof joists.

Security Diesel Generator Building. A single-story metal-sided enclosure with a built-up roof. The structure is supported by a reinforced concrete foundation on structural backfill.

Security Building (main access facility). A multi-story reinforced concrete structure with metal siding. The intermediate floor framing and reinforced concrete bearing walls are supported by reinforced concrete footings on structural backfill. The roof is a reinforced concrete deck with built-up roofing over rigid insulation.

Switchyard Control Building. A single-story concrete masonry block wall building with a built-up roof. The structure is supported by reinforced concrete footings on structural backfill.

Circulating and Service Water Pumphouse. A multi-story reinforced concrete and structural steel framed building supported by reinforced concrete footings on structural backfill. The roof consists of a built-up material over rigid insulation and metal deck supported by steel roof joists.

Cooling Tower Basin. A reinforced concrete slab with sidewalls founded on reinforced concrete piers and structural backfill. The structure provides water for the service water pumps supplying fire water to hose stations located in the essential service water pumphouse.

The intended function of the miscellaneous in-scope structures within the scope of license renewal is to provide structural support and protect SSCs that support fire protection (10 CFR 50.48) and SBO (10 CFR 50.63) in accordance with the requirements stated in 10 CFR 54.4(a)(3).

LRA Table 2.4-6 identifies the miscellaneous in-scope structures component types within the scope of license renewal and subject to an AMR.

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. On the basis of its review, the staff did not identify the need for any additional information.

2.4.6.3 Conclusion

On the basis of its review of the LRA and FSAR, the staff concludes that the applicant has appropriately identified the miscellaneous in-scope structures 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).

2.4.7 In-Scope Tank Foundations and Structures

2.4.7.1 Summary of Technical Information in the Application

In LRA Section 2.4.7, the applicant described in-scope tank foundations and structures as consisting of the seismic Category I safety-related RWST and valvehouse, and the nonsafety-related condensate storage tank (CST), CST trench, and the fire water storage tanks.

The intended functions of the in-scope tank foundations and structures within the scope of license renewal include the following:

- to provide structural support and protection for safety-related SSCs required for safe shutdown of the reactor
- to provide structural support and protect nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to provide structural support and protect SSCs that support fire protection (10 CFR 50.48) and SBO (10 CFR 50.63) in accordance with the requirements stated in 10 CFR 54.4(a)(3)

LRA Table 2.4-7 identifies the in-scope tank foundations and structures component types within the scope of license renewal and subject to an AMR.

2.4.7.2 Staff Evaluation

The staff reviewed LRA Section 2.4.7 and the FSAR 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 FSAR to verify that the applicant has not omitted from the scope of license renewal any SCs with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those SCs that the applicant has included within the scope of license renewal to verify that the applicant has not omitted any passive and long-lived SCs subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

During its review of LRA Section 2.4.7, the staff noted an area in which additional information was necessary to complete its review of the applicant's scoping and screening results.

The staff noted LRA Section 2.4.7 only lists the Category I safety-related RWST and valvehouse, the nonsafety-related CST, and the FWST as the tanks within the scope of license renewal. However for the structural foundations and supports of other safety-related tanks that are not specifically called out in the LRA, such as the component cooling water surge tank and the chemical and volume control system tank, it is not clear if the tank supports are analyzed under the specific LRA section that describes the structure that houses the tank, or as a separate commodity such as in LRA Section 2.4.7. By letter dated July 5, 2012, the staff issued RAI 2.4.7-1 requesting that the applicant clarify if the tank supports are analyzed under the specific LRA section that describes the structure that houses the tank, or as a separate commodity, such as in LRA Section 2.4.7. In its response letter dated August 6, 2012, the applicant stated that the foundations and associated structures for other in-scope tanks are evaluated as part of the buildings in which the tanks are located. For example, the component cooling water surge tanks are founded on a concrete slab within the auxiliary building which is evaluated under component type "concrete elements" in LRA Table 2.4-3. Supports that connect in-scope tanks to their foundations are evaluated as commodities in LRA Section 2.4.12, "Supports." These supports are included in LRA Table 2.4-12 as component types "Supports Mech Equip Class 1, [2, or 3,]" or "Supports Mech Equip Non-ASME," depending on the code class of the particular tank. Foundations and supports for all in-scope tanks are within the scope of license renewal and subject to AMR, while tanks are evaluated in their associated mechanical systems.

On the basis of its review, the staff finds the applicant response to RAI 2.4.7-1 acceptable because it clarified that the tank supports are analyzed under the specific LRA section that describes the structure that houses the tank and also identified the location within the LRA where the components were covered. Therefore, staff's concern described in RAI 2.4.7-1 is resolved.

2.4.7.3 Conclusion

On the basis of its review of the LRA, FSAR, and RAI response, the staff concludes that the applicant has appropriately identified the in-scope tank foundations and structures 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).

2.4.8 Electrical Foundations and Structures

2.4.8.1 Summary of Technical Information in the Application

In LRA Section 2.4.8, the applicant described electrical foundations and structures as consisting of reinforced concrete pads on structural backfill for station transformers (ESF, startup, main, unit auxiliary and station service). The purpose of the electrical foundations and structures is to support, shelter, and protect the station transformers, cables, and other in-scope electrical SSCs. The main and unit auxiliary transformers and support equipment are mounted on one common pad separated by concrete barrier walls while the two ESF transformers and support equipment are mounted on another common pad. The startup and station service transformers and associated support equipment are also mounted on separate pads. The seismic Category I electrical duct banks are located below grade and consist of a number of PVC conduits encased in reinforced concrete which house safety-related electrical cables. Duct banks also connect the ESF transformers to the turbine building and to the switchyard. Electrical manholes are reinforced concrete underground chambers founded on reinforced concrete slabs and are used

for installing and pulling electrical cables in the ductbanks. Transmission towers between the ESF and startup transformers are steel towers with reinforced concrete foundations.

The intended functions of the electrical foundations and structures within the scope of license renewal include the following:

- to provide structural support and protection for safety-related SSCs required for safe shutdown of the reactor
- to provide structural support and protect nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to provide structural support and protect SSCs that support fire protection (10 CFR 50.48) and SBO (10 CFR 50.63) in accordance with the requirements stated in 10 CFR 54.4(a)(3)

LRA Table 2.4-8 identifies the electrical foundations and structures component types within the scope of license renewal and subject to an AMR.

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. On the basis of its review, the staff did not identify the need for any additional information.

2.4.8.3 Conclusion

On the basis of its review of the LRA and FSAR, the staff concludes that the applicant has appropriately identified the electrical foundations and structures 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).

2.4.9 Radwaste Building

2.4.9.1 Summary of Technical Information in the Application

In LRA Section 2.4.9, the applicant described the purpose of the radwaste building as providing support, shelter, and protection for radioactive waste treatment facilities, tanks, filters, and other miscellaneous equipment. The building is a multi-story structural steel and reinforced concrete structure supported on a reinforced concrete mat foundation constructed on structural backfill, and has a built-up roof supported by structural steel beams and girders while the intermediate floor framing is supported by structural steel columns and reinforced concrete bearing walls.

The radwaste pipe tunnel is a below-grade, reinforced concrete, two-cell box structure connecting the auxiliary building and the radwaste building. The pipe tunnel provides access and carries electrical cable trays and piping between the auxiliary building and the radwaste building, and is separated from the connected auxiliary building by a fire wall barrier and isolation joints.

The intended function of the radwaste building within the scope of license renewal is to support fire protection (10 CFR 50.48) in accordance with the requirements stated in 10 CFR 54.4(a)(3).

LRA Table 2.4-9 identifies the radwaste building component types within the scope of license renewal and subject to an AMR.

2.4.9.2 Staff Evaluation

The staff reviewed LRA Section 2.4.9 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. On the basis of its review, the staff did not identify the need for any additional information.

2.4.9.3 Conclusion

On the basis of its review of the LRA and FSAR, the staff concludes that the applicant has appropriately identified the radwaste building 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).

2.4.10 Fuel Building

2.4.10.1 Summary of Technical Information in the Application

In LRA Section 2.4.10, the applicant described the fuel building as a multi-story seismic Category I structural steel and reinforced concrete structure supported by a two-way reinforced concrete base mat founded on structural backfill with reinforced concrete pilasters integral with the exterior walls. The elevated floors and roof are reinforced concrete slabs supported by structural steel beams and girders while the floor and roof framing are supported by reinforced concrete bearing walls.

The purpose of the fuel building is to provide support, shelter, and protection for the spent fuel pool, transfer canal, cask loading pool and cask washdown pit, spent fuel pool bridge crane, cask handling crane, and other miscellaneous equipment.

The intended functions of the fuel building within the scope of license renewal include the following:

- to provide structural support and protection for safety-related SSCs required to mitigate the consequences of accidents that could result in potential offsite exposure
- to provide structural support and protect nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to provide structural support and protect SSCs that support fire protection (10 CFR 50.48) in accordance with the requirements stated in 10 CFR 54.4(a)(3)

LRA Table 2.4-10 identifies the fuel building component types within the scope of license renewal and subject to an AMR.

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. On the basis of its review, the staff did not identify the need for any additional information.

2.4.10.3 Conclusion

On the basis of its review of the LRA and FSAR, the staff concludes that the applicant has appropriately identified the fuel building 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).

2.4.11 Essential Service Water Structures

2.4.11.1 Summary of Technical Information in the Application

In LRA Section 2.4.11, the applicant described ESW structures as those structures used to support, shelter, and protect the SSCs required for the ESW system and UHS. The ESW structures consist of the UHS cooling tower, ESW pumphouse, ESW system supply lines yard vault, and UHS retention pond and ancillary structures.

The intended functions of the ESW structures within the scope of license renewal include the following:

- to provide structural support and protection for safety-related SSCs required for safe shutdown of the reactor
- to provide structural support and protect nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to provide structural support and protect SSCs that support fire protection (10 CFR 50.48) in accordance with the requirements stated in 10 CFR 54.4(a)(3)

LRA Table 2.4-11 identifies the ESW structures component types within the scope of license renewal and subject to an AMR.

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. On the basis of its review, the staff did not identify the need for any additional information.

2.4.11.3 Conclusion

On the basis of its review of the LRA and FSAR, the staff concludes that the applicant has appropriately identified the ESW structures 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).

2.4.12 Supports

2.4.12.1 Summary of Technical Information in the Application

In LRA Section 2.4.12, the applicant described the supports commodity as including supports for American Society of Mechanical Engineers (ASME) Class 1, 2, and 3 piping and

components, and supports for non-ASME piping and components evaluated as commodities across system boundaries. Other commodity groups include cable trays and supports, conduits and supports, electrical panels and enclosures, instrument panels and racks, reactor vessel and steam generator supports, RCP and pressurizer supports, instrument tubing, and HVAC ducts.

The intended functions of the supports structures within the scope of license renewal include the following:

- to provide structural support and protection for safety-related components
- to provide structural support of nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function in accordance with the requirements of 10 CFR 54.4(a)(2)
- to provide structural support of components that support fire protection (10 CFR 50.48), ATWS (10 CFR 50.62), and SBO (10 CFR 50.63), in accordance with the requirements stated in 10 CFR 54.4(a)(3)

LRA Table 2.4-12 identifies the supports component types within the scope of license renewal and subject to an AMR.

2.4.12.2 Staff Evaluation

The staff reviewed LRA Section 2.4.12 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. On the basis of its review, the staff did not identify the need for any additional information.

2.4.12.3 Conclusion

On the basis of its review of the LRA and FSAR, the staff concludes that the applicant has appropriately identified the supports 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).

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

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

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

The staff's evaluation of the information in the LRA was the same for all electrical and I&C systems. The objective was to determine if the applicant has identified, in accordance with 10 CFR 54.4, components and supporting structures for electrical and I&C systems that appear to meet the license renewal scoping criteria. Similarly, the staff evaluated the applicant's

screening results to verify that all passive, long-lived components were subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In its scoping evaluation, the staff reviewed the applicable LRA sections and the RAI response, focusing on components that have not been identified as within the scope of license renewal. The staff reviewed the FSAR for each electrical and I&C system to determine if the application has omitted, from the scope of license renewal, 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 (1) the functions are performed with moving parts or a change in configuration or properties or (2) 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 Commodity Groups

2.5.1.1 Summary of Technical Information in the Application

LRA Section 2.5 describes the electrical and I&C systems. The scoping method includes all plant electrical and I&C components. Evaluation of electrical systems includes electrical and I&C components in mechanical systems. The default inclusion of plant electrical and I&C systems within the scope of license renewal reflects the method for the IPAs of electrical systems. This method is different from those for mechanical systems and structures.

The basic philosophy of the electrical and I&C components IPA is that components are included in the scoping review unless specifically screened out. The electrical and I&C IPA began by grouping all components into commodity groups of similar electrical and I&C components with common characteristics and by determining component level intended functions of the commodity groups.

The IPA eliminated commodity groups and specific plant systems from further review as the intended functions of commodity groups were examined. In addition to the plant electrical systems, certain switchyard components required to restore offsite power following SBO were included conservatively within the scope of license renewal even though those components are not relied on in the Callaway plant safety analyses or plant evaluations for functions that demonstrate compliance with the SBO regulation (10 CFR 50.63). The offsite power system evaluation boundaries are described next.

The offsite power system provides the electrical interconnection between the Callaway plant and the offsite transmission network. LRA Section 2.1.2.3.5 states the ESF transformers, startup transformer, overhead transmission lines, disconnects, overhead lines from disconnects to and including the switchyard breakers and the switchyard breaker control cables and connections are within the scope of license renewal as shown in Figure 2.1-2 of the LRA.

LRA Section 2.5 identifies electrical and I&C systems component types within the scope of license renewal and subject to an AMR:

- cable connections (metallic parts)
- connectors
- high voltage insulator

- insulated cable and connections
- switchyard bus and connections
- terminal blocks
- transmission conductors
- transmission connections
- electrical equipment subject to 10 CFR 50.49 EQ requirements
- metal enclosed bus
- mechanical EQ components
- fuse holders (not part of a larger assembly)
- penetrations, electrical
- grounding conductors
- cable tie wraps

The intended functions of the electrical and I&C systems component types within the scope of license renewal are to provide electrical continuity, expansion and separation, structural support, and electrical insulation.

2.5.1.2 Staff Evaluation

The staff reviewed Callaway LRA Section 2.5 and Unit 1 FSAR Sections 7 and 8 using the evaluation methodology described in SER Section 2.5 and the guidance in SRP-LR Section 2.5, "Scoping and Screening Results: Electrical and Instrumentation and Controls Systems."

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

General Design Criterion 17 of 10 CFR Part 50, Appendix A, requires, in part, that electric power from the transmission network to the onsite electric distribution system be supplied by two physically independent circuits to minimize the likelihood of their simultaneous failure. In addition, the staff noted that the guidance provided by letter dated April 1, 2002, "Staff Guidance on Scoping of Equipment Relied on to Meet the Requirements of the Station Blackout Rule (10 CFR 50.63) for License Renewal (10 CFR 54.4(a)(3))," (ADAMS Accession No. ML020920464) and later incorporated in SRP-LR Section 2.5.2.1.1, states 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 SBO requirements are maintained over the period of extended license.

In addition, the aforementioned guidance has been clarified in a license renewal interim staff guidance (ISG) document LR-ISG-2008-01, "Staff Guidance Regarding the Station Blackout Rule (10 CFR 50.63) Associated with License Renewal Applications," related to the SBO recovery path for license renewal. LR-ISG-2008-01 emphasizes that the SBO recovery path should include (1) the switchyard breakers at the transmission system (69 kV and higher) that connect to the offsite system power transformers; (2) the transformers themselves; (3) the intervening overhead or underground circuits between circuit breaker and transformer and transformer and onsite electrical distribution system; and (3) the associated control circuits and structures.

In its application dated December 15, 2011, the applicant described the SBO recovery path that was in the scope of license renewal. The applicant stated that the SBO recovery path included all the components and connections from the offsite power source, including switchyard transformers, high side disconnects, conductors, transformers, and buses up to the Callaway nuclear plant safeguards buses. Based on the above, the staff finds that the scope of the license renewal SBO recovery path is consistent with the scope of NUREG-1800, Revision 2, and, therefore, is acceptable.

During its review of LRA Section 2.5, the staff identified a need for additional information and, therefore, issued RAI 2.5-1 dated June 11, 2012, regarding the inclusion of control circuits of the switchyard circuit breakers (at the transmission voltage) in the scope of license renewal. In its response letter dated July 2, 2012, the applicant stated that the control circuits for the switchyard circuit breakers are included in the scope of license renewal as they are part of the SBO recovery path. The staff finds that the applicant's response is consistent with SRP-LR, and, therefore, is acceptable. The staff's concern described in RAI 2.5-1 is resolved.

2.5.1.3 Conclusion

The staff reviewed the LRA, FSAR, and RAI responses to determine if the applicant identified all SSCs within the scope of license renewal and to determine if the applicant had identified all components subject to an AMR. On the basis of its review, the staff concludes that the applicant adequately identified the electrical and I&C systems components within the scope of license renewal as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.6 Conclusion for Scoping and Screening

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

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

SECTION 3

AGING MANAGEMENT REVIEW RESULTS

This safety evaluation report (SER) section evaluates aging management programs (AMPs) and aging management reviews (AMRs) for Callaway Plant Unit 1 (Callaway) by the staff of the U.S. Nuclear Regulatory Commission (NRC or the staff).

In Appendix B of its license renewal application (LRA), Union Electric Company, doing business as Ameren Missouri (the applicant), described the 42 AMPs that it relies on to manage or monitor the aging of passive, long-lived structures and components (SCs).

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

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

In preparing its LRA, the applicant credited NUREG-1801, Revision 2, "Generic Aging Lessons Learned (GALL) Report," dated December 2010. The GALL Report contains the staff's generic evaluation of the existing plant programs and documents the technical basis for determining where existing programs are adequate without modification and where existing programs should be augmented for the period of extended operation. The evaluation results documented in the GALL Report indicate that many of the existing programs are adequate to manage the aging effects for particular license renewal SCs. The GALL Report also contains recommendations on specific areas for which existing programs should be augmented for license renewal. An applicant may reference the GALL Report in its LRA to demonstrate that its programs correspond to those reviewed and approved in the report.

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

The GALL Report identifies the following:

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

The staff performed its review in accordance with the requirements of Title 10, Part 54, of the *Code of Federal Regulations* (CFR), "Requirements for Renewal of Operating Licenses for

Nuclear Power Plants"; the guidance provided in NUREG-1800, Revision 2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR), dated December 2010; and the guidance provided in the GALL Report.

In addition to its LRA review, the staff conducted an onsite audit of selected AMPs during the weeks of April 30 and May 7, 2012, as described in the "Aging Management Programs audit report Regarding the Callaway Plant Unit 1 License Renewal Application," dated August 9, 2012. The onsite audits and reviews are designed for maximum efficiency of the staff's LRA review. The applicant can respond to questions, the staff can readily evaluate the applicant's responses, and the need for formal correspondence between the staff and the applicant is reduced, resulting in improvement review efficiency.

3.0.1 Format of the License Renewal Application

The applicant submitted an application that follows the standard LRA format agreed to by the staff and the Nuclear Energy Institute (NEI) by letter dated December 15, 2011.

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

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

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

The content of the previous LRAs and of the Callaway application is essentially the same. The intent of the revised format of the Callaway LRA was to modify the tables in LRA Section 3 to provide additional information that would assist in the staff's review. In Table 1s, the applicant summarized the portions of the application that it considered to be consistent with the GALL Report. In Table 2s, 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 3.x.1 (Table 1) provides a summary comparison of how the facility aligns with the corresponding tables of the GALL Report. The table is essentially the same as Tables 1 through 6 provided in the GALL Report, Volume 1, except that the "Type" column has been replaced by an "Item Number" column and the "Related Generic Item" and "Unique Item" columns have been replaced by a "Discussion" column. The applicant used the "Discussion" column to provide clarifying and amplifying information. The following are examples of information that might be contained within this column:

- further evaluation recommended—information or reference to where that information is located
- name of a plant-specific program
- exceptions to the GALL Report assumptions

- discussion of how the line is consistent with the corresponding AMR item in the GALL Report when the consistency may not be obvious
- discussion of how the item is different from the corresponding AMR item in the GALL Report (e.g., when an exception is taken to a GALL Report AMP)

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

3.0.1.2 Overview of Table 2s

Each Table 3.x.2-y (Table 2) provides the detailed AMR results for those components identified in LRA Section 2 as subject to an AMR. The LRA contains a Table 2 for each of the systems or components within a system grouping (e.g., reactor coolant systems (RCS), engineered safety features (ESF), auxiliary systems, etc.). For example, the ESF group contains tables specific to the containment spray system, residual heat removal (RHR) system, and safety injection system. Each Table 2 consists of the following nine columns:

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

(2) Intended Function: The second column identifies the license renewal intended functions, including abbreviations, where applicable, for the listed component types. Definitions and abbreviations of intended functions are in LRA Table 2.1-1.

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

(4) Environment: The fourth column lists the environments to which the component types are exposed. A list of these environments in LRA Tables 3.0-1. 3.0-2, and 3.0-3 indicates internal and external service environments.

(5) 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.

(6) AMPs: The sixth column lists the AMPs that the applicant uses to manage the identified aging effects.

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

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

(9) Notes: The ninth column lists the corresponding notes used to identify how the information in each Table 2 aligns with the information in the GALL Report. The notes, identified by letters, were developed by an NEI working group and will be used in future

LRAs. Any plant-specific notes identified by numbers provide additional information about the consistency of the AMR item with the GALL Report.

3.0.2 Staff's Review Process

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

(1) 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.

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

The SRP-LR states that an applicant may take one or more exceptions to specific GALL Report AMP elements; however, any 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 before the period of extended operation. Therefore, the staff considers these augmentations or additions to be enhancements. Enhancements include, but are not limited to, activities needed to ensure consistency with the GALL Report recommendations. Enhancements may expand, but not reduce, the scope of an AMP.

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

These audits and technical reviews of the applicant's AMPs and AMRs determine if the effects of aging on SCs can be adequately managed so that the intended functions can be maintained 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 those AMPs for which the applicant had claimed consistency with the GALL Report AMPs, the staff conducted either an audit or a technical review to confirm that the applicant's AMPs were consistent with the GALL Report. For each AMP that had one or more deviations, the staff evaluated each deviation to determine whether the deviation was acceptable and whether the AMP, as modified, would adequately manage the aging effect(s) for which it was credited. For AMPs that were not addressed in the GALL Report, the staff performed a full review to determine their adequacy. The staff evaluated the AMPs against the following 10 program elements defined in SRP-LR Appendix A:

(1) "scope of the program"—should include the specific SCs subject to a license renewal AMR.

(2) "preventive actions"—should prevent or mitigate aging degradation.

(3) "parameters monitored or inspected"—should be linked to the degradation of the particular structure or component-intended function(s).

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

(5) "monitoring and trending"—should provide predictability of the extent of degradation, as well as timely corrective or mitigative actions.

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

(7) "corrective actions"—these actions, including root cause determination and prevention of recurrence, should be timely.

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

(9) "administrative controls"—should provide for a formal review and approval process.

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

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

The staff reviewed the applicant's Quality Assurance (QA) Program and documented its evaluations in SER Section 3.0.4. The staff's evaluation of the QA Program included an assessment of the "corrective actions," "confirmation process," and "administrative controls" program elements.

The staff reviewed the information on the "operating experience" program element and documented its evaluation in SER Sections 3.0.3 and 3.0.5.

3.0.2.2 Review of AMR Results

Each LRA Table 2 contains information concerning whether the AMRs identified by the applicant align with the GALL Report AMRs. For a given AMR in a Table 2, the staff reviewed the intended function, material, environment, AERM, and AMP combination for a particular system component type. Item numbers in column seven of the LRA, "NUREG-1801 Item," correlate to an AMR combination as identified in the GALL Report. A blank in column seven indicates that the applicant was unable to identify an appropriate correlation in the GALL Report. The staff also conducted a technical review of combinations not consistent with the GALL Report. The next column, "Table 1 Item," refers to a number indicating the correlating row in Table 1.

For component groups evaluated in the GALL Report for which the applicant claimed consistency and for which it does not recommend further evaluation, the staff determined, on the basis of its review, 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 audited these items to verify consistency with the GALL Report and validity of the AMR for the site-specific conditions.

Note B indicates that the AMR item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff audited these items to verify consistency with the GALL Report and confirmed that the identified exceptions to the GALL Report AMPs have been reviewed and accepted. The staff also determined whether the applicant's AMP was consistent with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report; however, the applicant identified in the GALL Report a different component with the same material, environment, aging effect, and AMP as the component under review. The staff audited these items to verify consistency with the GALL Report. The staff also determined if the AMR item of the different component was applicable to the component under review and if the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff audited these items to verify consistency with the GALL Report. The staff confirmed whether the AMR item of the different component was applicable to the component under review and whether the identified exceptions to GALL Report AMPs have been reviewed and accepted. The staff also determined if the applicant's AMP was consistent with the GALL Report AMP and if the AMR was valid for the site-specific conditions.

Note E indicates that the AMR item is consistent with the GALL Report for material, environment, and aging effect, but it credits a different AMP. The staff audited these items to verify consistency with the GALL Report. The staff also determined if the credited AMP would manage the aging effect consistently with the GALL Report AMP and if the AMR was valid for the site-specific conditions.

The applicant defined its mechanical service environments in LRA Table 3.0-1. LRA Table 3.0-1 states that the Callaway water environments encompass the GALL Report defined water environments for water temperatures both above and below 60°C (140°F). For example, the "closed cycle cooling water" environment in the LRA encompasses the GALL Report defined environments of "closed cycle cooling water" and "closed cycle cooling water > 60°C (140°F)." Also, the "secondary water" environment in the LRA encompasses the GALL Report defined environments of "treated water" and "treated water > 60°C (140°F)." GALL Report Section IX.D indicates that the susceptibility of stainless steels to stress-corrosion cracking (SCC) in water environments depends on whether the water temperature is above or below 60°C (140°F).

Because the applicant defined its water environments as encompassing the GALL Report defined water environments for water temperatures both above and below the stress corrosion cracking threshold, the staff could not determine if the proper aging effects and aging management programs had been identified for those AMR items exposed to water environments. By letter dated July 5, 2012, the staff issued Request for Additional Information (RAI) 3.0.1-1 requesting that the applicant (a) identify which components are exposed to water environments with temperatures greater than the stress corrosion cracking threshold and (b) add AMR items to manage stress corrosion cracking, as necessary.

In its response dated August 6, 2012, the applicant stated that stainless steel components exposed to water environments greater than 60°C (140°F) have an aging effect of cracking. The applicant provided a list of LRA tables that include such components, and it also revised LRA Table 3.3.2-22 to add AMR items for stainless steel components in the standby diesel generator engine system that are susceptible to stress corrosion cracking.

In a teleconference with the applicant dated August 23, 2012, the staff requested clarification of the applicant's response regarding which AMR items in the LRA have a water environment with a temperature greater than 60°C (140°F). The applicant clarified that it reviewed the LRA and confirmed that all stainless steel components that are exposed to water environments with temperatures greater than 60°C (140°F) have an AMR item for cracking caused by stress corrosion cracking (i.e., the cracking aging effect can be used as an indicator of an elevated temperature water environment in the LRA). In the teleconference, the staff also discussed the applicant's list of affected LRA tables, which appeared to be incomplete. By letter dated September 18, 2012, the applicant supplemented its original RAI response to add additional tables to the list of those containing affected components.

The staff finds the applicant's response, as supplemented, acceptable because the applicant identified which stainless steel components in the LRA are exposed to water environments with temperatures greater than 60°C (140°F), such that the staff can determine whether the proper aging effects and aging management programs have been identified. The staff's individual AMR item evaluations for components exposed to water environments are documented in the appropriate SER sections for their associated LRA Table 1 references. The staff's concern described in RAI 3.0.1-1 is resolved.

3.0.2.3 FSAR Supplement

Consistent with the SRP-LR, for the AMRs and associated AMPs that it reviewed, the staff also reviewed the final safety analysis report (FSAR) supplement that summarizes the applicant's programs and activities for managing the effects of aging for the period of extended operation, as required by 10 CFR 54.21(d).

3.0.2.4 Documentation and Documents Reviewed

In performing its review, the staff used the LRA, LRA supplements, the SRP-LR, the GALL Report, and Requests for Additional Information (RAI) responses. Also, during the onsite audit, the staff examined the applicant's justifications, as documented in the audit summary report, to verify that the applicant's activities and programs will adequately manage the effects of aging on SCs. The staff also conducted detailed discussions and interviews with the applicant's license renewal project personnel and others with technical expertise relevant to aging management.

3.0.3 Aging Management Programs

SER Table 3.0-1 below presents the AMPs credited by the applicant and described in LRA Appendix B. The table also indicates the GALL Report AMP that the applicant claimed its AMP was consistent with and whether the program is a new or existing AMP. The SER section in which the staff's evaluation of the program is documented also is provided.

Table 3.0-1 Callaway Aging Management Programs

Applicant AMP	LRA sections	New or existing program	Applicant comparison to the GALL Report	GALL Report AMPs	SER section
[American Society of Mechanical Engineers] ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	A1.1 B2.1.1	Existing	Consistent	XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	3.0.3.1.1
Water Chemistry	A1.2 B2.1.2	Existing	Consistent	XI.M2, "Water Chemistry"	3.0.3.1.2
Reactor Head Closure Studs Bolting	A1.3 B2.1.3	Existing	Consistent	XI.M3, "Reactor Head Closure Stud Bolting"	3.0.3.1.3
Boric Acid Corrosion	A1.4 B2.1.4	Existing	Consistent with enhancements	XI.M10, "Boric Acid Corrosion"	3.0.3.2.1
Cracking of Nickel-Alloy Components and Loss of Material Caused by Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components	A1.5 B2.1.5	Existing	Consistent	XI.M11B, "Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components"	3.0.3.1.4
PWR Vessel Internals	A1.6 B2.1.6	New	Consistent	XI.M16A, "PWR Vessel Internals"	3.0.3.1.5
Flow-Accelerated Corrosion	A1.7 B2.1.7	Existing	Consistent	XI.M17, "Flow-Accelerated Corrosion"	3.0.3.1.6
Bolting Integrity	A1.8 B2.1.8	Existing	Consistent with enhancements	XI.M18, "Bolting Integrity"	3.0.3.2.2
Steam Generators	A1.9 B2.1.9	Existing	Consistent	XI.M19, "Steam Generators"	3.0.3.1.7
Open-Cycle Cooling Water System	A1.10 B2.1.10	Existing	Consistent with enhancements	XI.M20, "Open-Cycle Cooling Water System"	3.0.3.2.3
Closed Treated Water Systems	A1.11 B2.1.11	Existing	Consistent with enhancements	XI.M21A, "Closed Treated Water Systems"	3.0.3.2.4
Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	A1.12 B2.1.12	Existing	Consistent with enhancements	XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems"	3.0.3.2.5
Fire Protection	A1.13 B2.1.13	Existing	Consistent with enhancements	XI.M26, "Fire Protection"	3.0.3.2.6

Applicant AMP	LRA sections	New or existing program	Applicant comparison to the GALL Report	GALL Report AMPs	SER section
Fire Water System	A1.14 B2.1.14	Existing	Consistent with enhancements and exceptions	XI.M27, “Fire Water System”	3.0.3.2.7
Aboveground Metallic Tanks	A1.15 B2.1.15	New	Consistent with exception	XI.M29, “Aboveground Metallic Tanks”	3.0.3.2.8
Fuel Oil Chemistry	A1.16 B2.1.16	Existing	Consistent with enhancements	XI.M30, “Fuel Oil Chemistry”	3.0.3.2.9
Reactor Vessel Surveillance	A1.17 B2.1.17	Existing	Consistent with enhancements	XI.M31, “Reactor Vessel Surveillance”	3.0.3.2.10
One-Time Inspection	A1.18 B2.1.18	New	Consistent	XI.M32, “One-Time Inspection”	3.0.3.1.8
Selective Leaching	A1.19 B2.1.19	New	Consistent with exception	XI.M33, “Selective Leaching”	3.0.3.2.11
One-Time Inspection of ASME Code Class 1 Small-Bore Piping	A1.20 B2.1.20	New	Consistent	XI.M35, “One-Time Inspection of ASME Code Class 1 Small-Bore Piping”	3.0.3.1.9
External Surfaces Monitoring of Mechanical Components	A1.21 B2.1.21	New	Consistent	XI.M36, “External Surfaces Monitoring of Mechanical Components”	3.0.3.1.10
Flux Thimble Tube Inspection	A1.22 B2.1.22	Existing	Consistent	XI.M37, “Flux Thimble Tube Inspection”	3.0.3.1.11
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	A1.23 B2.1.23	New	Consistent with exception	XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	3.0.3.2.12
Lubricating Oil Analysis	A1.24 B2.1.24	Existing	Consistent with enhancement	XI.M39, “Lubricating Oil Analysis”	3.0.3.2.13
Buried and Underground Piping and Tanks	A1.25 B2.1.25	New	Consistent with exceptions	XI.M41, “Buried and Underground Piping and Tanks”	3.0.3.2.14
ASME Section XI, Subsection IWE	A1.26 B2.1.26	Existing	Consistent with enhancements	XI.S1, “ASME Section XI, Subsection IWE”	3.0.3.2.15
ASME Section XI, Subsection IWL	A1.27 B2.1.27	Existing	Consistent	XI.S2, “ASME Section XI, Subsection IWL”	3.0.3.1.12
ASME Section XI, Subsection IWF	A1.28 B2.1.28	Existing	Consistent with enhancements	XI.S3, “ASME Section XI Subsection IWF”	3.0.3.2.16
10 CFR PART 50, Appendix J	A1.29 B2.1.29	Existing	Consistent	XI.S4, “10 CFR Part 50 Appendix J”	3.0.3.1.13
Masonry Walls	A1.30 B2.1.30	Existing	Consistent	XI.S5, “Masonry Walls”	3.0.3.1.14
Structures Monitoring	A1.31 B2.1.31	Existing	Consistent with enhancements	XI.S6, “Structures Monitoring”	3.0.3.2.17
RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	A1.32 B2.1.32	Existing	Consistent	XI.S7, “RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants”	3.0.3.1.15

Applicant AMP	LRA sections	New or existing program	Applicant comparison to the GALL Report	GALL Report AMPs	SER section
Protective Coating Monitoring and Maintenance Program	A1.33 B2.1.33	Existing	Consistent with enhancements and exception	XI.S8, “Protective Coating Monitoring and Maintenance Program”	3.0.3.2.18
Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	A1.34 B2.1.34	Existing	Consistent with enhancements	XI.E1, “Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements”	3.0.3.2.19
Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	A1.35 B2.1.35	Existing	Consistent with enhancements	XI.E2, “Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits”	3.0.3.2.20
Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	A1.36 B2.1.36	Existing	Consistent with enhancements	XI.E3, “Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements”	3.0.3.2.21
Electrical Cable Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements	A1.37 B2.1.37	New	Consistent	XI.E6, “Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements”	3.0.3.1.16
Monitoring of Neutron-Absorbing Materials Other than Boraflex	A1.38 B2.1.38	New	Consistent	XI.M40, “Monitoring of Neutron-Absorbing Materials Other than Boraflex”	3.0.3.1.17
Metal Enclosed Bus	A1.39 B2.1.39	New	Consistent	XI.E4, “Metal Enclosed Bus”	3.0.3.1.18
Fatigue Monitoring	A2.1 B3.1	Existing	Consistent with enhancements	X.M1, “Fatigue Monitoring”	3.0.3.2.22
Environmental Qualification (EQ) of Electrical Components	A2.2 B3.2	Existing	Consistent	X.E1, “Environmental Qualification (EQ) of Electric Components”	3.0.3.1.19
Concrete Containment Tendon Prestress	A2.3 B3.3	Existing	Consistent with enhancements	X.S1, “Concrete Containment Tendon Prestress”	3.0.3.2.23

3.0.3.1 AMPs Consistent with the GALL Report

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

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
- Water Chemistry
- Reactor Head Closure Stud Bolting
- Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components
- [Pressurized Water Reactor (PWR)] Vessel Internals
- Flow-Accelerated Corrosion
- Steam Generators
- One-Time Inspection
- One-Time Inspection of ASME Code Class 1 Small-Bore Piping
- External Surfaces Monitoring of Mechanical Components
- Flux Thimble Tube Inspection
- ASME Section XI, Subsection IWL
- 10 CFR PART 50, Appendix J
- Masonry Walls
- RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants
- Electrical Cable Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements
- Monitoring of Neutron-Absorbing Materials Other than Boraflex
- Metal Enclosed Bus
- Environmental Qualification (EQ) of Electrical Components

3.0.3.1.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

Summary of Technical Information in the Application. LRA Section B2.1.1 describes the existing American Society of Mechanical Engineers (ASME) Section XI Inservice Inspection (ISI), 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 LRA states that this program manages cracking, loss of fracture toughness, and loss of material in Class 1, 2, and 3 piping and components within the scope of license renewal. The LRA also states that this program includes periodic visual, surface, volumetric examinations, and leakage tests of Class 1, 2, and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting.

In addition, the LRA states that these components are identified in ASME Code Section XI Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1 for Class 1, 2, and 3 components, respectively. The LRA states that the program directs that repair and replacement activities be

performed in accordance with IWA-4000. The LRA further states that this program is updated during each successive 120-month (i.e., 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 compared program elements one through six of the applicant's program to the corresponding program 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 Tables IWB-2500-1 and IWC-2500-1 are used to determine the examination requirements for Class 1 and Class 2 components, respectively. The staff noted that the applicant implemented risk-informed inservice inspections (RI-ISI) with Examination Category R-A in lieu of Categories B-F, B-J, C-F-1, and C-F-2 for the current 10-year ISI interval as approved by the NRC. The RI-ISI provides alternative inspection requirements for a subset of Class 1 and Class 2 piping welds. The staff also noted that the use of RI-ISI is only approved for the current 10-year ISI interval. Future implementation of the RI-ISI is subject to NRC approval, in accordance with 10 CFR Part 55.55a, for each subsequent 10-year ISI interval, including the period of extended operation. The staff confirmed during the onsite audit that the applicant's ISI Program plan calls for a review of the RI-ISI implementation for future inspection intervals. The staff finds this acceptable because the applicant will need NRC approval for use of this RI-ISI relief request for future inspection intervals.

In addition, the staff noted that the applicant updates its program every 10 years (120 months) to the latest ASME Code Section XI as approved by the NRC before the start of the inspection interval. The applicant's ISI Program is currently in the third 10-year ISI interval, from December 19, 2004, to December 18, 2014. The applicant's fourth 10-year ISI interval will be from December 19, 2014, to December 18, 2024. The proposed period of extended operation will commence on October 19, 2024. The current ASME Code of record for the applicant's ISI Program is the ASME Code Section XI 1998 Edition with 2000 addenda of the ASME Code.

Based on its audit, and review of the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD 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.M1.

Operating Experience. LRA Section B2.1.1 summarizes operating experience related to the ASME 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 industrywide operating experience, research data, and technical evaluations. The applicant stated that plant-specific examples are documented in its ISI Summary Reports, as well as in the Corrective Action Program (CAP) records.

LRA Section B2.1.1 also provides a specific example of the applicant's operating experience. The LRA states that during refueling outage (RFO) 13 (spring 2004) the ISI examination detected one indication in a nozzle weld that required an evaluation for continued operation. The applicant's evaluation concluded that the indication was a result of fabrication. The flaw had propagated to the inside surface, but the growth toward the outside surface was minimal to

nonexistent. The flaw was found to be acceptable by analytical evaluation, as allowed by ASME Code Section XI, Section IWB-3600. Based on a technical evaluation of the indication, the course of action was to monitor the indication for change. The LRA states that the monitoring will use the same nondestructive evaluation (NDE) techniques as the current to ensure accurate comparison. The LRA also states that the monitoring interval coincides with the ASME Code's requirement for re-inspection within 3 years. The LRA further states that a subsequent inspection was performed during RFO 15 in 2007 and indicated that the flaw had not grown. In addition, the flaw also will be examined in RFO 19 in 2013 and in RFO 21 in 2016 or RFO 22 in 2017.

The staff reviewed operating experience information in the application and during the audit to determine if the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the audit report, the staff conducted an independent search of the plant operating experience information to determine if the applicant had adequately evaluated and incorporated operating experience related to this program

The staff also performed an independent search of plant operating experience related to the applicant's program. During its audit and 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.

The staff reviewed the applicant's ISI summary reports dated from 1999 to 2012 and noted that degradation, including multiple pin hole leaks, have been detected in the site's essential service water (ESW) piping system. However, it was not clear to the staff how these aging effects were effectively addressed since no details had been provided. By letter dated July 18, 2012, the staff issued RAI B2.1.1-1 requesting the applicant to discuss and justify the ISI Program's effectiveness in addressing the noted aging effects in light of the failures, as documented in its ISI summary reports.

In its response dated August 21, 2012, the applicant stated that most of the leaks identified in the ISI summary reports from 1999 to 2012 have been in the ESW system. The applicant stated that "leaks were caused or exacerbated by microbiologically-[influenced] corrosion (MIC) of carbon steel surfaces." The applicant also stated that the failures were addressed effectively and the number of leaks detected was drastically decreased in recent ISI Program inspections. In its response, the applicant provided detailed corrective actions and mitigative measures that the ISI Program implemented to address the aging effects. The measures included enhancement of chemistry control in the ESW system and replacement of susceptible and degraded piping with more corrosion-resistant piping. The applicant further stated that the positive trend in recent inspections indicates that the aging effects have been addressed. The staff noted the corrective actions and mitigative measures that the applicant's program implemented. As part of the corrective actions, the applicant has replaced the degraded piping with more corrosion-resistant piping. In addition, the applicant has improved its water treatment to eliminate the root cause, as part of its mitigative measures. The staff also noted that there were significantly fewer leaks in the most recent ISI Program inspections, indicating that the program's implementation has been effective in addressing aging and degradation. The staff finds the applicant's response acceptable because the applicant performed appropriate corrective actions and adequate mitigative measures to address the aging effects. Therefore, the staff's concern described in RAI B2.1.1-1 is resolved.

Based on its audit, review of the application, and review of the applicant's response to RAI B2.1.1-1, the staff finds that the applicant has appropriately evaluated plant-specific and

industry operating experience and that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.M1 was evaluated.

FSAR Supplement. LRA Section A1.1, as amended by letter dated February 14, 2013, provides the FSAR supplement for the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The FSAR supplement was amended in response to RAI B2.1.5-4b discussed in SER Section 3.0.3.1.4. The staff reviewed this FSAR supplement description of the program and noted that it is consistent with the recommended description for this type of program, as described in SRP-LR Table 3.0-1. The staff finds that the information in the FSAR supplement, as amended by letter dated February 14, 2013, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD 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 function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.2 Water Chemistry

Summary of Technical Information in the Application. LRA Section B2.1.2 describes the existing Water Chemistry Program as consistent with GALL Report AMP XI.M2, "Water Chemistry." The LRA states that the Water Chemistry Program manages loss of material, cracking, reduction of heat transfer, and wall thinning in components exposed to a treated water environment. The program comprises the primary water chemistry program, which includes monitoring and control of the chemical environment in the RCS and related auxiliary systems, and the secondary water chemistry program, which includes monitoring and control of the chemical environment in the steam generator secondary side and the secondary cycle systems. The LRA states that the primary water chemistry program is consistent with Electric Power Research Institute (EPRI) 1014986, Revision 6, "PWR Primary Water Chemistry Guidelines," Volumes 1 and 2, and the secondary water chemistry program is consistent with EPRI 1016555, Revision 7, "PWR Secondary Water Chemistry Guidelines." The LRA also states that the One-Time Inspection Program will be used to verify the effectiveness of the Water Chemistry Program.

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. 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.

Operating Experience. LRA Section B2.1.2 summarizes operating experience related to the Water Chemistry Program. A summary of the operating experience is given below.

- In 2004, the applicant replaced the main condenser tube bundles with 316L stainless steel tube sheets and stainless steel tubes. Previously, the main condenser consisted mostly of 90/10 copper/nickel and some small percentage of 304 stainless steel tubes.
- Following the replacement of the steam generators in 2005, the applicant implemented an optimized methoxy-propyl-amine/ethanol-amine chemistry plan, which, along with the replacement of key susceptible piping with more corrosion resistant material, significantly reduced corrosion transport rates in the extraction steam and drain piping.
- In 2005, just after replacement of the steam generators, RCS samples indicated high sulfate concentration. The sulfate spike later was identified as oxalic acid, which is found in lubricants used in cutting, drilling, and hydrostatic expansion of the steam generator components. Oxalates degrade the performance of ion chromatographs, causing false sulfate measurements. The oxalates were removed by the letdown mixed beds.
- In 2005, the Callaway pressurizer liquid space had a dissolved oxygen concentration of 500 parts per billion (ppb) just after an insurge of RCS water was allowed to cool the pressurizer surge line. Pressurizer liquid-space oxygen concentration was monitored every 6 hours until oxygen concentration came back down to within specification (less than 100 ppb). In 2010, the dissolved oxygen concentration in the pressurizer liquid space exceeded 100 ppb for approximately 16 hours because of premature initiation of pressurizer spray while in Mode 5.
- Since cycle 15, Callaway has run on no condensate polisher operation, except for shutdowns, startups, and chemical and other transients, and with methoxy-propyl-amine/ethanol-amine chemistry and use of the blowdown demineralizers as the main secondary chemistry control. The applicant stated that it plans to continue to run in a no-polisher mode.
- In March 2007, a major sodium, sulfate, and chloride intrusion from a condenser circulating water tube rupture caused a plant shutdown. A single tube rupture was located in the condenser. The applicant determined that the rupture was the result of the failure of a 10-inch slope-drain angle iron. The applicant repaired the support.
- In 2007, the applicant evaluated NRC Information Notice (IN) 2007-37, “Buildup of Deposits in Steam Generator.” The applicant determined that the Callaway Steam Generator Program was not affected because the contributing factors cited in the IN are not present at Callaway. The applicant also performed a secondary-side sludge loading analysis and determined that the actions that it has taken to reduce the amount of corrosion products in the secondary systems have been effective.

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 that implementation of the program has resulted in the applicant taking corrective action. In addition,

the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.M2 was evaluated.

FSAR Supplement. LRA Section A1.2 provides the FSAR supplement for the Water Chemistry Program. The staff reviewed this FSAR 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 FSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Water Chemistry 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 function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff reviewed the FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.3 Reactor Head Closure Stud Bolting

Summary of Technical Information in the Application. LRA Section B2.1.3 describes the existing Reactor Head Closure Stud Bolting Program as consistent, with GALL Report AMP XI.M3, "Reactor Head Closure Stud Bolting." The LRA states that the Reactor Head Closure Stud Bolting Program manages cracking and loss of material by conducting ASME Code Section XI inspections of reactor vessel flange stud hole threads, reactor closure studs, nuts, and washers. The LRA also states that the program uses visual and volumetric examinations in accordance with the general requirements of ASME Code Section XI, Subsection IWA-2000. The LRA further states that examination and inspection requirements specified in the ASME Code Section XI, Subsection IWB, Table IWB-2500-1, are used. The LRA states that reactor vessel studs are removed from the reactor vessel flange during each RFO, when possible. In addition, the LRA states that if a stud is stuck, a stainless steel or fiberglass protective cover is installed before cavity flooding. The LRA also states that the program has proven to be effective in preventing and detecting potential aging effects of reactor vessel flange stud hole threads, closure studs, nuts, and washers.

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 "detection of aging effects" and "monitoring and trending" program elements, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

During the LRA review and the audit of the applicant's operating experience for the AMP, the staff noted that on several occasions, the applicant's closure studs became stuck during stud insertion or removal activities. During RFO 3 (spring 1989), five stuck studs were destructively removed from their reactor pressure vessel (RPV) flange stud hole locations. Subsequent to the removal of the studs, the applicant determined that the corresponding RPV lower flange stud hole locations had damaged threads, which resulted in fewer threads than the original design. In addition, during stud installation in RFO 8 (fall 1996), stud No. 18 became stuck with only partial RPV flange hole thread engagement (i.e., the stud was not completely threaded into the hole). The staff noted that stud No. 18 has not been removed during subsequent outages. The staff is concerned that examinations performed in accordance with the Reactor Head Closure Stud Bolting Program may not be capable of detecting loss of material for the flange hole threads or quantifying the amount of wear or damage of the portion of the threads thought to be engaged. In addition, the staff noted that, when studs are stuck in place, corrosion due to

the boric acid environment during cavity flooding could go unmonitored if the studs were never removed for examination.

By letter dated July 18, 2012, the staff issued RAI B2.1.3-1 to request that the applicant clarify how the program will detect loss of material caused by wear or corrosion (including potential boric acid corrosion) and quantify the potential amount of damage in areas of the studs and lower flange (including engaged threaded regions and remaining stud hole areas below the stud bottom faces), when a stud is not removed during an outage.

In its response dated August 21, 2012, the applicant stated that it currently has only one stuck stud (No. 18), which has been stuck since 1996 and is threaded to 2.625 in. above the base of the stud hole (i.e., 6.505 in. of thread engagement). The applicant stated that, since the minimum required thread engagement length is 6.31 in., stud No. 18 meets the requirement for minimum thread engagement. The applicant also stated that inspection of stud No. 18, before reactor vessel head installation, identified a small burr on the 10th and 11th threads; the burr was removed, and no other problems were noted with the stud threads. The applicant further stated that the stud hole threads were also inspected, and no damage was found. In addition, the applicant stated that when the stud became stuck, excessive force was not used to force it in, or remove it. Thus, the applicant stated its belief that no thread damage was caused by actions taken after the stud became stuck.

Furthermore, the applicant stated that, in preparation for refueling, when the stuck stud is de-tensioned, a stress of 65,000 psi is successfully applied, which provides further evidence that there is no thread damage. The applicant noted that during normal operations, the stress is approximately 39,400 psi. The applicant also stated that, during an RFO, stud No. 18 is protected from exposure to borated water in the refueling pool by encapsulation to prevent corrosion caused by exposure to boric acid. The applicant further stated that it performs inspection of the stuck stud as required by ASME Code Section XI, and it believes that stud No. 18 will continue to perform its intended function.

The staff finds that the applicant's response did not address the following issues: (1) the number of threads that may have been damaged as a result of stud No. 18's getting stuck, (2) uniform wear, and (3) corrosion. In addition, it is not clear from the applicant's response if the noted inspections associated with stud No. 18 were performed right before it became stuck. The applicant's response is also not specific in how ASME Code Section XI inspections can verify the current number of threads that are properly engaged for stud No. 18, particularly since the stud has not been removed since getting stuck in 1996. Furthermore, the staff needs clarification of the applicant's basis for stating that the stuck stud has 6.505 in. of thread engagement remaining and that the required minimum thread engagement is 6.31 in. By letter dated October 24, 2012, the staff issued RAI B2.1.3-1a to request that the applicant provide additional information regarding its basis for determining that all the engaged threads for stud No. 18 are undamaged. In addition, the staff requested that the applicant provide the analyses used to support the determinations that stud No. 18 has 6.505 in. of thread engagement and that the required minimum thread engagement is 6.31 in.

In its response dated November 20, 2012, the applicant stated that the threads for stud No. 18 and its stud hole were inspected immediately prior to installation of the stud and found to be intact at that time. The applicant also stated that, when the stud became stuck, excessive force was not used in an attempt to free the stud, and therefore no threads were damaged by installation of the stud. The applicant further stated that, although the threads of stud No. 18 have not been inspected for damage caused by wear or corrosion, the other 53 reactor vessel

studs and stud holes have been inspected. The applicant also stated that, since 1992, no damage to the threads of the other studs and stud holes has been observed. The applicant further stated that, since stud No. 18 is exposed to the same environment as the other studs, except during refueling, it is reasonable to conclude that damage to the threads caused by corrosion or wear has not occurred. The applicant also stated that the ultrasonic test (UT) examination is capable of identifying cracking and severe corrosion of the threads.

In addition, the applicant provided a sketch of the stuck stud and stud hole to demonstrate its basis that, with the stud 2.625 in. from the bottom of the stud hole, the stuck stud still has 6.505 in. of thread engagement. The applicant also provided the basis that only 6.31 in. of thread engagement is required.

The staff finds that the applicant's response still did not address the possibility of thread damage to the vessel flange or stud threads, as a result of the stud's becoming stuck. In addition, in its previous response the applicant had stated that a burr was removed from threads 10 and 11 on stud No. 18 just before the stud was inserted.

The staff noted that the applicant did not appropriately consider the unique condition for the stuck stud. Specifically, the staff noted that the stresses would be higher for the stuck stud than at other locations because of less thread engagement. Furthermore, the staff noted that the applicant assumes that future tensioning and de-tensioning operations will not cause any wear, and that there will be no loss of material because of corrosion. This reasoning is non-conservative and contrary to the engineering evaluations performed in 1989, which recommended that if damage approaches the limiting value (6.31 in. of engagement or 19.5 threads missing), or if the vessel is operated with a missing stud, vessel hydrotest should be avoided, and the plant heat up rate should be limited to half the design value to minimize the risk of localized plastic deformation.

The staff also noted that, as stated by the applicant in its response, the current UT examinations performed on the stuck stud and its flange hole would only be able to detect cracking or severe thread corrosion. Since the number of fully engaged threads for this location is near the acceptance level, a marginal reduction in the number of properly engaged threads may bring the effective number of engaged threads below the acceptance criteria. Furthermore, the staff does not agree with the applicant's assertion that the conditions at this location are typical of the remaining 53 locations. Specifically, since the stud at location No. 18 is stuck 2.625 in. from the bottom of the flange hole and has fewer threads engaged than normal, it has higher stresses than those that have no thread damage or more threads engaged. As stated earlier, this location would be more susceptible to localized plastic deformation.

Since the applicant's stated acceptance criteria for the minimum allowable thread engagement (6.31 in.) is very close to the acceptable calculated thread engagement for stud No. 18 (6.505 in.), the staff does not have reasonable assurance that the applicant's current UT examinations will detect thread degradation prior to exceeding the acceptance criteria.

By letter dated March 26, 2013, the staff issued follow-up RAI B2.1.3-1b, requesting that the applicant clarify how the Reactor Head Closure Stud Bolting Program will detect thread damage on stud and vessel flange hole threads at locations with stuck studs. In its response dated April 26, 2013, the applicant stated, in part, that detensioning of stud No. 18 during each RFO confirms its intended function will be maintained. The applicant also stated that normal RPV head stud tensioning and detensioning operations performed during each RFO are a form of "proof test" of the adequacy of the threaded connection to support inservice RPV head stud loads. The applicant further stated that the minimum RPV head stud load experienced by RPV

head stud No. 18 during detensioning is a 113-percent proof test of the maximum inservice primary plus secondary RPV head stud loading during heatup.

The applicant stated that the 1987 evaluation which calculated the RPV head stud minimum thread engagement (6.31 in.) was based on a conservative methodology. The applicant also stated that an evaluation performed in 2013 demonstrates that the minimum RPV head stud engagement required to resist all primary loads is 4.77 in. The applicant further stated that the stuck stud No. 18 nominally has in excess of 35 percent more thread engagement than is required to meet American Society of Mechanical Engineers (ASME) Code limits, and that the margin is sufficiently large that the comments related to plastic deformation in the 1989 evaluations do not apply to RPV stud No. 18.

The applicant stated that although the condition of the threads on the inside of the RPV head stud hole No. 18 cannot be observed through direct visual examination, the 2013 evaluation performed a bounding estimate based on the amount of force used during efforts to remove stud No. 18 and concluded that the effective damage could be no more than 20 percent of a single thread, which would result in less than 0.025 in. of lost effective thread engagement.

The applicant also stated that stud No. 18 is protected from boric acid corrosion by encapsulation during refueling to prevent exposure to the boric acid in the refueling pool. The applicant further stated that most wear occurs when an RPV head stud is threaded in and out of the RPV head stud hole. Since stud No. 18 is stuck, it is not being removed or installed, therefore essentially there is no wear (loss of material).

In addition, the applicant stated that the existing RPV head stud handling procedures and practices do not damage threads. The applicant stated that with the exception of minor maintenance on RPV head stud No. 18 (burr removal in 1996) and RPV head stud No. 20 (chasing lead threads), no threads have been damaged in over 20 years. The applicant also stated that it has not destructively removed an RPV head stud since 1989, when five stuck studs were removed due to their interference with the fuel transfer path and to restore functionality to RPV head stud No. 2. The applicant further stated that, at that time, the risks associated with destructive removal, which included possible introduction of foreign material, worker safety, dose exposure, possibility of additional damage during the repair process, technical challenges associated with the RPV head stud removal tooling, and failure to restore the normal fuel transfer path, were acceptable in order to repair the RPV. Finally, the applicant stated that given the above considerations, it is considered appropriate to monitor and manage the continued use of RPV head stud No. 18 rather than pursue its removal.

The staff finds that the applicant's response did not fully address how the condition of the threads for the RPV head stud and stud hole No.18 would be monitored during the period of extended operation. In its response the applicant stated that normal RPV head stud tensioning and detensioning operations performed during each RFO is a form of "proof test" of the adequacy of the threaded connection to support inservice RPV head stud loads for the subsequent cycle. The staff does not agree that successful tensioning and detensioning provides adequate assurance that the threads will withstand all inservice loads in the subsequent operating cycle. Specifically, the tensioning and detensioning is usually performed at ambient temperature. In addition, during tensioning and detensioning, some of the stresses may be distributed or shared by the adjacent studs and flange ligaments, while during inservice transients the adjacent areas may not be able to share as much of the stresses.

Furthermore, the staff noted that the applicant is essentially assuming zero corrosion at the location of the stuck stud, because the stuck stud is encapsulated during RFOs. The staff noted

that leakage past the encapsulation may occur along with leakage past the inner O-ring, and therefore loss of material at this location is an aging effect which requires management during the period of extended operation.

By letter dated August 2, 2013, the staff issued RAI B2.1.3-1c, requesting the applicant explain how the current aging management program (AMP) will monitor the condition of the threads on the stud and vessel flange hole threads, so that there is reasonable assurance that the known degradation and any postulated degradation along with the number of unengaged threads will not exceed the acceptance criteria during the period of extended operation.

In its response dated August 29, 2013, the applicant stated that it manages cracking and loss of material for RPV stud and stud hole No. 18 consistent with the Reactor Head Closure Bolting Program and in accordance with the ASME Section XI. The applicant also stated that RPV stud and stud hole No. 18 are protected from exposure to the borated water of the refueling pool to prevent loss of material due to corrosion. The applicant further stated that to allow for monitoring of the condition of the threads of the RPV stud and stud hole No. 18 relative to aging, it will remove stud No. 18 through a nondestructive or destructive means. The applicant also stated that the removal will be scheduled no later than 6 months prior to the period of extended operation or the refueling outage prior to the period of extended operation, whichever occurs later. The applicant further stated that if repair of the stud hole is required subsequent to the stud removal, the repair plan would include inspection prior to and after the repair to access the as-found conditions and the results of the repair. As part of its response, the applicant amended LRA Table A4-1 and added Commitment No. 41, which states:

> To allow for monitoring of the condition of the threads on the RPV stud and flange hole threads, Callaway commits to remove RPV stud No. 18 through nondestuctive or destructive means. If RPV stud hole repair is required following removal of the RPV stud No. 18, the repair plan will include inspecting the RPV stud hole prior to the repair to assess the as-found condition and an inspection after the repair is completed to assess the results of the repair.

In order to ensure that the condition of the threads for RPV stud and stud hole No.18 can be monitored, so that there is a reasonable assurance that it can perform its intended function through the period of extended operation, the staff will issue a license condition to the applicant. The license condition will require the applicant to remove the stuck stud prior to entering the period of extended operation. Therefore, the staff's concerns described in RAIs B2.1.3-1, B2.1.3-1a, B2.1.3-1b, and B2.1.3-1c are resolved.

Based on its audit and review of the applicant's Reactor Head Closure Stud Bolting Program and review of the applicant's responses to RAIs B2.1.3-1, B2.1.3-1a, B2.1.3-1b, and B2.1.3-1c, the staff finds that the program elements 1 through 6, for which the applicant claimed consistency with the GALL Report, are consistent with the corresponding program elements of GALL Report AMP XI.M3.

Operating Experience. LRA Section B2.1.3 summarizes operating experience related to the Reactor Head Closure Stud Bolting Program. The applicant stated that review of owner activity reports for RFO since 1996 indicates that there were no repair or replacement items identified with reactor vessel closure studs, nuts, washers, or flange stud hole threads. The LRA states that during RFO 8 (fall 1996) a stud became stuck during installation, as discussed in the staff's evaluation regarding stud No. 18 above.

The applicant also stated that Callaway experienced problems with other stuck reactor head closure studs. Specifically, during RFO 2 (fall 1987) five reactor head closure studs could not be removed from the reactor vessel flange. The applicant further stated that the studs were cut out during RFO 3 (spring 1989).

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 audit and 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.

The staff noted that there may be additional RPV flange stud holes that may have damaged threads. Specifically, RPV flange stud hole location Nos. 2, 4, 5, 7, 9, 13, 18, 25, 39, 53, and 54 may have missing or damaged threads. The total number of locations with possible damaged threads represents more than 20 percent of the applicant's total RPV closure stud bolting.

By letter dated July 18, 2012, the staff issued RAI B2.1.3-2, requesting that the applicant:

(a) Identify all RPV flange assembly studs or stud hole locations that have had past experience with stuck studs, damage, or missing stud/stud hole threads. For each location, identify when the issue was first detected, and summarize the corrective actions taken to resolve the issue.

(b) Clarify how the AMP performs "monitoring and trending" of relevant operating experience, and include an explanation on the type of evaluations that will be performed in individual stud or stud hole problems detected at the plant and of the entire RPV flange, based on the latest configuration of the flange assembly. Clarify how the evaluations will be used to reconcile the latest, as-known configuration of the RPV flange assembly against the applicable ASME Code Section III design requirements.

In its response dated August 21, 2012, the applicant provided a summary description of the problems encountered with its reactor vessel head closure stud bolting. The applicant stated that the Reactor Head Closure Stud Bolting Program owner monitors the operating experience associated with the reactor head closure studs, nuts, and stud holes, such as repairs, replacements, prior evaluations or calculations, and documented aging effects. The applicant also stated that evaluations of reactor vessel head closure stud and stud hole problems, such as stuck studs or missing threads, are initiated through use of the applicant's corrective action program. The applicant further stated that inputs to the evaluations consider all relevant information, including ASME Code requirements, the latest vendor calculations, and operating experience such as repairs, replacements, prior evaluations, and documented aging effects. In addition, the applicant stated that these evaluations are performed in accordance with applicable plant procedures for repairs, design changes, or calculations, as appropriate for the disposition.

In its review of the applicant's response, the staff noted that the applicant's summary of the problems encountered with its RPV closure stud bolting was not complete in that it did not include information on stud Nos. 15 and 35, whose inspection reports the staff reviewed during its audit and indicated that the studs for these locations were replacement studs. The staff

needed additional information to understand the nature of these replacements (i.e., whether they were replaced because of damage).

Furthermore, based on the assessment in the applicant's response, there was no consideration of the cumulative impact of the degraded closure stud bolting over the years on the entire RPV flange assembly. Because of the cumulative number of damaged stud holes and their locations throughout the RPV flange, the staff is concerned that assessments to justify adequate thread engagement for individual stud holes may not consider the overall impact of other degraded studs within the vicinity of one another. Moreover, the staff is uncertain how future RPV closure stud bolting issues will be assessed during the period of extended operation in this respect (e.g., if additional stud locations became damaged over time). The staff's concern is based on the fact that currently at least 10 closure stud bolting locations have some degradation in the form of missing threads. In addition, stud No. 18 has been stuck in a partially engaged position since fall 1996.

By letter dated October 24, 2012, the staff issued RAI B2.1.3-2a, requesting that the applicant supplement RAI B2.1.3-2 to provide information on all RPV closure stud bolting corrective actions, repair, and replacement activities performed to date, which were not included in its response letter dated August 21, 2012. In addition, the staff also requested that the applicant provide a condition assessment and evaluations that justify the adequacy of the entire RPV flange assembly, which accounts for all of the locations with known closure stud bolting degradation.

In its response dated November 20, 2012, the applicant stated that review of plant records confirmed that reactor vessel stud No. 15 was replaced in June of 1984, and stud No 35 was replaced in the spring of 1989. The applicant also stated that these studs were replaced because of thread damage. The applicant further stated that no other repair or replacement activities were discovered in the review of plant records.

In addition, the applicant provided a brief summary of two engineering evaluations which were performed on its reactor vessel head closure studs in 1987 and 1989. The applicant stated that the two evaluations which were performed in 1987 and 1989 related to the problems the applicant has experienced with the reactor vessel studs and flange threads. The applicant also stated that both of the evaluations addressed minimum thread engagement, and based on those evaluations, the value of 6.31 in. has been used by the applicant to determine acceptability of the reactor vessel stud thread engagement. The applicant further stated that the 1989 evaluation provided criteria for taking partial credit for damaged threads; however, all damaged threads were removed from the stud holes in 1989 and 1992, and all studs with damaged threads were replaced.

The applicant stated that the first evaluation was performed in 1987, when in RFO 2, five reactor vessel studs became stuck. The applicant also stated that the evaluation provided justification for operation in the subsequent cycle with one stud untensioned and the other four studs with partial engagement. The applicant further stated that the evaluation provided three recommendations in addition to the conclusion that the plant could operate with stud No. 2 untensioned. The applicant stated that all three recommendations were satisfied.

In addition, the applicant stated that the purpose of the 1989 report was to develop criteria to accept or reject reactor vessel thread degradation on a generic basis. The applicant also stated that the report also provided five recommendations. The applicant stated that it has met all five recommendations.

During its review, the staff noted that both evaluations (1987 and 1989) assumed that, with the exception of the five stud hole locations (2, 4, 5, 7, and 9), all the other remaining studs and stud hole threads had no degradation. Furthermore, the 1989 report also anticipated that a laser inspection technique would be used to accurately evaluate thread damage at the facility, noting that the laser inspection technique would yield high quality profiles of damaged threads; the report further stated that care should be exercised in the evaluation of areas with uniform wear, because they may appear intact but may in fact be out of tolerance. It is not clear to the staff whether the applicant has employed this specific technique in evaluating thread damage.

In contrast to the conditions assumed in the 1987 and 1989 evaluations, additional stud hole locations have known thread damage (i.e., 13, 25, 39, 53, and 54). Furthermore, stud No. 18 has been stuck since 1996, with partial thread engagement. The staff also noted that the affected locations are mostly on one side of the reactor vessel flange periphery.

In addition, during review of the applicant's reply, the staff noted that recommendation 2 (from the 1989 report), stated, in part, that studs used in vessel flange holes with degraded threads should be free from damage. Since the applicant stated that a burr was removed from threads 10 and 11 on the No. 18 stud, it is not clear to the staff that recommendation 2 from the 1989 report will be met for this location. Furthermore, recommendation 4 (also from the 1989 report) stated, in part, that if damage approaches the limiting values, or if the vessel is operated with a missing stud, vessel hydrotests should be avoided, and the plant heatup rate limited to 50 °F/hr in order to minimize the risk of localized plastic deformation of the threads. It is not clear to the staff that this aspect of recommendation 4 is met.

By letter dated March 26, 2013, the staff issued RAI B2.1.3-2b, requesting that the applicant clarify if the thread inspections for the vessel flange hole and stud threads include a laser inspection method referenced in the 1989 report, which can accurately gauge thread degradation so that there is assurance that any damage which is present does not exceed the acceptance criteria prior to the next inspection. In addition, the evaluations performed in 1987 and 1989 assumed that, with the exception of location nos. 2, 4, 5, 7, and 9, there were no other locations with damaged threads. Since additional damage has occurred, the applicant was also requested to provide justification that the evaluations and the acceptance criteria provided by these reports will be valid during the period of extended operation and that the overall adequacy of the entire RPV flange assembly will be adequately managed during the period of extended operation.

In its response dated April 26, 2013, the applicant stated that during the 1989 and 1992 repairs, a tool specially designed for inspection of RPV stud holes was used which produced a high-quality video of the stud hole threads by using a laser to illuminate and map the profile of the threads. The applicant stated that the laser inspection tool was used before and after the repairs. The applicant also stated that, since 1992, due to improved RPV head stud handling procedures, only one minor indication was found on RPV stud hole No. 20 threads. The applicant further stated that the laser inspection device has not been used since 1992.

In addition the applicant stated that the 1989 evaluation was intended to apply to the remainder of the "RPV design life" and does not include a discussion on the pattern of the degraded RPV head at that time, rather the thread damage existing at that time was used only to support the discussions estimating the effective thread engagement in hole locations 2, 4, 5, 7, and 9. The applicant also stated that thread damage to RPV stud hole Nos. 13, 25, 39, 53, and 54, subsequent to the 1989 evaluations, do not invalidate past evaluations as long as the minimum thread engagement criteria are met. The applicant further stated that the thread degradation

evaluation criteria developed in the 1989 report was analyzed such that each RPV stud engagement region fully meets applicable ASME Code rules, provided that the thread degradation evaluation criteria are met for each vessel stud hole. The applicant stated that using this evaluation, the RPV flange as a whole would fully meet ASME Code rules even if the effective thread engagement of all 54 RPV head stud locations were at a minimum. The applicant stated that there is no interaction mechanism between adjacent RPV stud hole locations, provided that each one meets the acceptance criteria established in the 1989 evaluation.

The applicant also stated that Recommendation 2 from the 1989 evaluation, which stated that "studs used in vessel flange holes with degraded threads should be free from damage," was based on the assumption that the vessel threads would engage with RPV head stud threads that were each fully intact. The applicant stated that use of RPV head stud No. 18 after removing a small burr was not in conflict with the recommendation that "studs used in vessel flange holes with degraded threads should be free of damage." The applicant further stated that the recommendations of the 1989 evaluations are considered to be optional since the language used was "should" rather than "must" or "shall."

The applicant stated that the 1987 evaluation calculated a 6.31-in. minimum vessel/stud thread engagement length based on a conservative calculation methodology. However, a 2013 evaluation demonstrates that the minimum vessel/stud engagement required to resist all primary loads is 4.77 in. The applicant also stated that the stuck RPV head stud No. 18 has in excess of 35 percent more thread engagement than is required to meet ASME Code limits. The applicant further stated that this margin is sufficiently large that the comments related to localized plastic deformation do not apply to stuck stud No. 18.

During its review, the staff noted that the evaluations (1987 and 1989), essentially used similar language such as "should" rather than "must" or "shall." This is because at the time these evaluations were performed the applicant had other options, such as the option to repair the RPV stud hole locations with stud hole inserts. However, in pursuing the continued use of the 1987 and 1989 evaluations to justify the use of the RPV closure bolting in its current condition (i.e., with multiple locations with less than full thread engagement), the use of the recommendations should not be considered as "optional" by the applicant. In addition, since these evaluations are only valid if the acceptance criteria are still being met, the staff still seeks assurance that, for location Nos. 2, 4, 5, 7, 9, 13, 18, 25, 39, 53, and 54, the minimum thread engagement criteria will continue to be met during the term of the renewed license, with sufficient margin such that there is an extremely low probability of abnormal leakage, rapidly propagating failure, and gross rupture. The staff also noted that the applicant in its response stated that the 1989 evaluation was intended to apply to the remainder of the RPV design life. The staff reviewed the license renewal application (LRA) and did not note that the 1989 evaluation was identified as time-limited aging analysis (TLAA), the applicant's response did not provide additional information for the staff to determine whether this evaluation should have been identified as a TLAA in the LRA.

By letter dated August 2, 2013,the staff issued RAI B2.1.3-2c, requesting the applicant explain:

> (1) What is meant by the term "remainder of the RPV design life," as discussed above. In addition, clarify whether the 1987 and 1989 evaluations should be identified as TLAAs in accordance with 10 CFR 54.3. If the evaluations are identified as TLAAs, revise the LRA accordingly and provide TLAA disposition in accordance with 10 CFR 54.21(c)(1). If not, provide the justifications why these evaluations are not considered as TLAAs.

2) How the current AMP will monitor the condition of the threads such that there is adequate assurance that the acceptance criteria will continue to be met at repaired RPV stud hole location Nos. 2, 4, 5, 7, 9, 13, 18, 25, 39, 53, and 54 during the period of extended operation.

In its response dated August 29, 2013, the applicant responded to Part (1) of RAI B2.1.3-2c and stated that the 1987 evaluation addressed questions relating to plant operation with RPV stud No. 2 not tensioned and unknown thread conditions in RPV stud holes 4, 5, 7, and 9. The applicant also stated that the 1987 evaluation discussed a number of different issues that were germane to the circumstances of the fall 1987 refueling outage, and this report was specific to the pattern of stuck studs and the known thread degradation that existed at that time. The applicant further stated that the calculation in 1987 provided the basis for the applicant to operate during Cycle 3 and was communicated to NRC by letter ULNRC-1663 dated October 29, 1987.

The applicant stated that the stud and flange conditions described in the 1987 evaluation have been repaired and therefore are no longer representative of the current stud and flange conditions. The applicant also stated that, since the 1987 evaluation does not provide the basis for the current conclusion related to the capability of the reactor vessel studs, stud holes, or flange to perform their intended functions, the evaluation is not a TLAA in accordance with 10 CFR 54.3(a), criterion 5.

The applicant also stated that the 1989 evaluation provided acceptance criteria for thread degradation and the starting point of the evaluation was related to the reactor vessel flange condition as it was known in 1989. In addition, the applicant stated that the evaluation itself did not contain any time-limited assumptions. The applicant further stated that its response to RAI B2.1.3-2b inadvertently introduced the statement that the 1989 evaluation was “intended to apply to the remainder of the RPV design life.” The applicant stated that the phrase was meant to convey that the 1989 evaluation was forward-looking rather than a snapshot in time and could be used to evaluate similar future conditions should the need arise. The applicant also stated that since the analyses contained in the 1989 evaluation are not time-dependent, this analysis is not a TLAA in accordance with 10 CFR 54.3(a), criterion 3.

The staff finds the applicant’s response acceptable because the applicant clarified that it inappropriately introduced the statement “intended to apply to the remainder of the RPV design life,” in its response to staff’s RAI. In addition, the applicant reiterated that the 1989 evaluations which provided its acceptance criteria for the RPV threads did not contain any time-limited assumption and the analysis is not time dependent. The staff’s concerns described in RAI B2.1.3-2c, Part (1), are resolved.

In its response to Part (2) of RAI B2.1.3-2c, the applicant stated that its RPV closure stud and stud holes experienced problems early in plant life (1986-1992), and multiple RPV stud holes required ASME Section XI repairs to remove damaged threads. The applicant also stated that, to supplement the monitoring that is accomplished through regular volumetric inspections and to confirm that additional thread degradation has not occurred in the RPV stud holes, it commits to perform a one-time inspection of select RPV stud holes (Nos. 2, 4, 5, 7, 9, and 53) using a method consistent with the laser inspection that was applied following stud hole repair in 1989 and 1992. The applicant also stated that if inspection of these RPV stud holes confirms that there was minimal or no additional degradation since the prior inspections, then it is reasonable to conclude that there will be minimal additional degradation in the period of extended operation. The applicant further stated that, if additional degradation is observed, the condition will be

entered in the Corrective Action Program for evaluation and corrective action, and the remaining RPV stud hole locations will be inspected (Nos. 13, 25, 39, and 54). The applicant stated that the inspections will be completed no later than 6 months prior to the period of extended operation or the refueling outage prior to the period of extended operation, whichever occurs later. As part of its response, the applicant amended LRA Table A4-1 and added Commitment No. 42, which states:

> It is noted that Callaway experienced problems with the reactor vessel head closure studs and stud holes early in plant life (1986-1992) and that multiple RPV stud holes required ASME Section XI repairs to remove damaged threads. To supplement the monitoring that is accomplished through regular volumetric inspections and to confirm that additional thread degradation is not occurring in the RPV stud holes, Callaway commits to perform a one-time inspection of select RPV stud holes using a method consistent with the Babcock and Wilcox laser inspection that was applied following stud hole repair in 1989 and 1992. RPV stud hole locations 2, 4, 5, 7, 9, and 53 have had more than one thread removed and will be inspected. If inspection of these RPV stud holes confirms that there was minimal or no additional degradation since the prior video inspection, then it is a reasonable conclusion that there will be minimal additional degradation in the period of extended operation. If additional degradation is observed in any of the repaired stud holes where more than one thread has been removed, the condition will be entered in the Corrective Action Program for evaluation and corrective action, and the remaining repaired RPV stud hole locations 13, 25, 39, and 54 will be inspected. The inspection is expected to confirm that further degradation is not occurring in the repaired stud holes, and will provide a basis for the conclusion that acceptance criteria for thread engagement will continue to be met through the period of extended operation.

In order to ensure that the condition of the threads for the RPV stud holes can be monitored, so that there is adequate assurance that the stud holes with less than the number of designed threads can continue to perform their intended function through the period of extended operation, the staff will issue a license condition to the applicant. The license condition will require the applicant perform laser inspection for the threads of stud hole location Nos. 2, 4, 5, 7, 9, and 53. If inspection of these RPV stud holes confirms that there is additional degradation observed in any of these stud holes, the condition will be entered in the Corrective Action Program for evaluation and corrective action. In addition, the remaining repaired RPV stud hole locations Nos. 13, 25, 39, and 54 will be inspected. Therefore, the staff's concerns described in RAIs B2.1.3-2, B2.1.3-2a, B2.1.3-2b, and B2.1.3-2c are resolved.

Based on its audit and review of the application, and review of the applicant's response to RAIs B2.1.3-2, B2.1.3-2a, B2.1.3-2b, and B2.1.3-2c, and review of the applicant's commitments, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. In addition, the staff finds that, when implemented, the applicant's program can adequately manage the effects of aging on SSCs within the scope of the program.

FSAR Supplement. LRA Section A1.3, as amended by letter dated August 29, 2013, provides the FSAR supplement for the Reactor Head Closure Stud Program. The staff reviewed the FSAR 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 to completing Commitment Nos. 41 and 42 no later than 6 months prior to the period of extended operation or the refueling outage prior to the period of extended operation, whichever occurs later. As stated earlier in this section, the staff will issue license conditions to

ensure that these commitments are completed prior to entering the period of extended operation.

The staff finds that the information in the FSAR supplement, as amended by letter dated August 29, 2013, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Reactor Head Closure Stud Bolting Program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the applicant's Commitment Nos. 41 and 42 and confirmed that their implementation through license conditions 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 FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.4 Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components

Summary of Technical Information in the Application. LRA Section B2.1.5 describes the existing Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components Program as consistent with 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 LRA states that the Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components Program manages cracking of nickel-alloy components and associated welds as well as loss of material caused by boric acid-induced corrosion in susceptible components in the vicinity of nickel-alloy reactor coolant pressure boundary (RCPB) components. The LRA also states that detection of aging is accomplished through examinations consistent with ASME Code Section XI Subsection IWB Code Case N-722-1, subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(E), ASME Code Case N-729-1, subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D), and ASME Code Case N-770-1, subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(F). The LRA further states that this program provides for bare-metal visual, surface, and volumetric examinations of nickel-alloy components, and for pressure boundary leakage and signs of boric acid leakage on adjacent ferritic steel components.

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.M11B. For the "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 "parameters monitored or inspected" program element described in the applicant's program evaluation report indicates that cracking and leakage of the RCPB are monitored by the applicant's ISI program as augmented by ASME Code Cases N-722-1, N-729-1, and N-770-1, subject to the conditions specified in 10 CFR 50.55a. The applicant's third interval ISI plan also indicates that the applicant's program uses ASME Code Cases N-722-1, N-729-1, and N770-1 in accordance with 10 CFR 50.55a. In comparison, GALL Report AMP XI.M11B recommends

that RCPB cracking and leakage should be monitored by the applicant's ISI program in accordance with 10 CFR 50.55a.

ASME Code Case N-770-1, in part, specifies visual examinations to detect reactor coolant leakage and boric acid corrosion associated with ASME Code Class 1 pressure retaining dissimilar metal piping and vessel nozzle welds. During the audit, the staff noted that the third-interval examination schedule for the applicant's ISI program plan and the procedure for boric acid walkdown do not clearly indicate the implementation of visual examinations specified in ASME Code Case N-770-1.

By letter dated July 18, 2012, the staff issued RAI B2.1.5-1 requesting that the applicant clarify why the applicant's examination schedule for ISI and implementing procedure for a boric acid walkdown do not clearly indicate the implementation of the visual examinations that are specified in ASME Code Case N-770-1. The staff also requested that as part of the response, the applicant confirm whether the implementing procedures or examination schedules of the ISI adequately implement visual examination, as specified in Inspection Items A-1 and A-2 of ASME Code Case N-770-1 (i.e., unmitigated butt welds at hot-leg operating temperatures to be examined by visual examinations during each RFO).

In its response dated August 21, 2012, the applicant indicated that the implementation procedure for aging management of Alloy 600 components provides guidance for ASME Code Case N-770-1 examination requirements for the different ASME Code Class 1 Alloy 82/182 dissimilar metal butt welds. The applicant also stated that the following procedures are being enhanced to reference implementation and scheduling of ASME Code Case N-770-1 as applicable for implementation and scheduling of visual examinations: (1) QCP-ZZ-05048, "Boric Acid Walkdown for RCS Pressure Boundary," (2) QCP-ZZ-05041, "Visual Examination to ASME VT-2," and (3) Third Interval ISI Program Plan Appendix D.

The staff finds the applicant's response acceptable because the applicant initiated the revisions to the procedures as applicable for implementation and scheduling of visual examinations in accordance with ASME Code Case N-770-1, consistent with its program basis document and GALL Report AMP XI.M11B. The staff's concern described in RAI B2.1.5-1 is resolved.

The "detection of aging effects" program element described in the applicant's program evaluation report indicates that the program includes examinations in accordance with the requirements of ASME Code Section XI, as augmented by ASME Code Cases N-722-1, N-729-1, and N-770-1, subject to the conditions specified in 10 CFR 50.55a. The staff also noted that applicant's operating experience indicates that refueling cavity seal leakage caused a potential to interfere with the visual examinations of dissimilar metal welds on the reactor vessel loop nozzles and bottom-mounted instrument (BMI) penetrations.

Therefore, the staff needed to confirm whether the applicant's operating experience indicates any other previous or current leakage that may interfere with the visual examinations of the reactor vessel nozzles specified in ASME Code Case N-770-1 and the other RCPB components specified in ASME Code Case N-722-1. In addition, the applicant's implementing procedure for boric acid walkdown for the RCS does not clearly address how the applicant's procedure would resolve the situation when leakage from other locations interferes with the visual examinations of the reactor vessel nozzle welds and other RCPB components specified in ASME Code Cases N-770-1 and N-722-1.

By letter dated July 18, 2012, the staff issued RAI B2.1.5-2 requesting that the applicant describe the corrective action that was taken to prevent the refueling cavity seal leakage and to

correct the conditions (e.g., corrosion product buildup) that would potentially interfere with the visual examination of dissimilar metal welds on the reactor vessel loop nozzles and BMI penetrations. The staff also requested that if applicable, the applicant describe any other previous or current leakage that may interfere with the visual examinations of the dissimilar metal welds on the reactor vessel nozzles, the BMI penetrations, or the other components included in the scope of the program. The staff further requested that the applicant describe how the applicant's implementing procedures would resolve the situation when leakage from the other locations interferes with the visual examination of the RCPB components specified in ASME Code Cases N-770-1 and N-722-1.

In its response dated August 21, 2012, the applicant stated that its "[CAP] is used to address reactor cavity seal ring leakage that could potentially interfere with the visual examination of dissimilar metal welds on the reactor vessel loop nozzles and [BMI] penetrations." The applicant also provided a summary of its corrective actions taken over the past 10 years to prevent refueling cavity seal leakage and potential interference of the leakage with the applicant's visual examinations. The corrective actions include maintenance and replacement activities for the refueling cavity seals, cleaning of reactor vessel nozzles, and confirmation that inspection areas are free of boron residues with no interference with visual examinations. The applicant further stated that after the final draining of the refueling cavity during a RFO, it ensures that any residue due to cavity seal leakage, which might interfere with the examination of the RV nozzles, RV bottom head, or BMI penetrations that will be inspected during the next refueling outage, is removed,

In its response, the applicant stated that no leakage other than the previously discussed cavity seal leakage has occurred that may affect the inspections of the applicant's program. The applicant also stated that the dissimilar metal welds on the reactor vessel are examined and cleaned as necessary at the end of each RFO to remove any residue from refueling operations, which could interfere with the examination for leakage at the beginning of the next refueling outage. The applicant further stated that visual examination on specific Inconel (Alloy 600/82/182 and 690/52/152) components is conducted on the bare surface of the area of interest in accordance with the applicant's implementing work documents. In addition, the applicant indicated that the invoking work document specifies that debris or other restrictions to the examinations are to be removed or resolved for adequate inspection of the components.

In its response, the applicant clarified that its procedures for boric acid walkdown for the RCS pressure boundary require that if boric acid residues are detected on or in the vicinity of components, a corrective action document is generated to evaluate leakage. The applicant also indicated that if boric acid deposits are discovered on the surface of the reactor vessel head or related insulation, regardless of the source or manner found, an examination is performed of the affected area(s) to verify the integrity of the reactor vessel head and penetrations before returning the plant to operation.

The staff finds the applicant's response acceptable because: (1) the applicant confirmed that it has taken corrective actions in response to the previous concerns related to potential interference with the visual examinations of its program; (2) the applicant uses its CAP to ensure that reactor cavity seal ring leakage events or other leakage events do not potentially interfere with the visual examinations of the reactor vessel loop nozzles and BMI penetrations; (3) the applicant confirmed that after the draining of the refueling cavity, it ensures that any residue due to cavity seal leakage is removed; and (4) the applicant's implementing procedures (work documents) for visual examinations ensure that debris or other restrictions to the

examination are to be removed or resolved. The staff's concern described in RAI B2.1.5-2 is resolved.

Based on its audit of the applicant's Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components Program and review of the applicant's responses to RAIs B2.1.5-1 and B2.1.5-2, 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.M11B.

Operating Experience. LRA Section B2.1.5 summarizes operating experience related to the Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components Program. The LRA states that during RFO 15 (spring 2007), the reactor vessel head penetrations were examined using volumetric and surface techniques, and no evidence of cracking or leak path was identified with the volumetric and surface examinations. The LRA also states that no evidence of leakage from the penetration nozzles or indications of wastage was identified during bare metal visual examinations. In addition, the LRA states that during RFO 15, the applicant's RPV hot-leg and cold-leg nozzles were volumetrically examined, and no evidence of cracking or leak path was identified in the nozzle to pipe dissimilar metal welds.

As discussed above, the applicant's program includes volumetric and visual examinations of Class 1 pressure retaining dissimilar metal piping and vessel nozzle welds that are specified in ASME Code Case N-770-1. Inspection Items of ASME Code Case N-770-1, A-1 and A-2 specify the examinations for unmitigated butt welds at hot-leg operating temperatures greater than 329 °C (625 °F) and equal or less than 329 °C (625 °F), respectively.

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 the audit, the staff noted that the applicant's operating experience indicates that the RCS has experienced reactor hot-leg temperature fluctuations associated with changes in adjacent hot-leg temperatures. This phenomenon has been referred to by the term "upper plenum anomaly" (UPA) and apparently is caused by a flow switching phenomenon in the reactor vessel upper plenum.

The UPA may increase the local temperatures of the reactor hot-leg nozzles above 329 °C (625 °F) because of nonsymmetrical flow mixing such that Inspection Item A-1, rather than A-2, should be applied to the inspections of the applicant's reactor hot-leg nozzles. It was not clear to the staff how the applicant's program evaluates the potential effects of the UPA on the reactor hot-leg nozzle temperatures and the determination of the inspection items.

By letter dated July 18, 2012, the staff issued RAI B2.1.5-3 requesting the applicant to provide the following information to confirm that its program uses relevant inspection items in accordance with ASME Code Case N-770-1: (1) inspection item assigned to unmitigated hot-leg nozzle butt welds (that is, Inspection Item A-1 or A-2), and (2) the temperatures of the

hot-leg nozzles based on adequate consideration of the local temperature distributions and fluctuations at the hot-leg nozzles. The staff also requested that as part of the response the applicant describe how the temperatures of the hot-leg nozzles are determined (e.g., an engineering evaluation or actual measurements). In addition, the staff requested that if the applicant's inspection item for the unmitigated hot-leg nozzle welds is A-2 and the maximum temperature of the hot-leg nozzles exceeds 329 °C (625 °F), the applicant should clarify why its program does not specify Inspection Item A-1 to the hot-leg nozzle welds exposed to temperatures exceeding 329 °C (625 °F). The staff further requested that the applicant describe the operating experience in terms of occurrence of primary water stress-corrosion cracking (PWSCC) in the hot-leg nozzles to confirm whether the UPA has an adverse effect on PWSCC of the hot-leg nozzles.

In its response dated August 21, 2012, the applicant stated that its UPA manifests itself in pairs of loops; and in the loop 2 and loop 3 hot-legs, loop 2 has a higher temperature than loop 3. The applicant also stated that "[w]hen the UPA occurs, the temperature in loop 2 temporarily decreases, accompanied by a corresponding increase in loop 3 temperature, [and] after a few seconds, the temperatures return to normal." The applicant further stated that "[w]hen the temperature in loop 3 increases, it does not increase above the temperature in loop 2 prior to the onset of the UPA event." The applicant further stated that "[l]oops 1 and 4 behave in a similar fashion, with the temperature in loop 1 normally higher than the temperature in loop 4. Thus, the UPA does not affect the maximum temperature of the reactor hot leg nozzles."

In its response, the applicant also stated that "[e]ach hot-leg has three [resistance temperature detectors (RTDs)] installed 120 degrees apart [and] [c]omputer logs of all the RTDs were reviewed back to 2005, when the steam generators were replaced." The applicant indicated that during that time period, except during calibration of an RTD, none of the RTDs indicated a temperature greater than 327 °C (620 °F). The applicant also stated that based on this review ASME Code Case N-770-1 Inspection Item A-2 is assigned. The applicant further stated that no cracks have been found in the RCS hot-leg nozzles.

In its review, the staff found the applicant's response acceptable because: (1) the measured temperature data of the RTDs since 2005 confirm that the maximum temperature of the reactor hot-leg nozzles is less than the minimum threshold temperature 329 °C (625 °F) for Inspection Item A-1; (2) the applicant adequately assigned Inspection Item A-2 to the reactor vessel outlet nozzles based on the measured temperature data, consistent with ASME Code Case 770-1; and (3) the applicant confirmed that no cracks have been found in the RCS hot-leg nozzles, which indicates that the UPA did not cause an adverse effect on PWSCC of the hot-leg nozzles. The staff's concern described in RAI B2.1.5-3 is resolved.

LRA Section B2.1.5 addresses the operating experience regarding the reactor vessel lower head cladding by stating that an indication was visually detected in the reactor vessel lower head cladding in 2007, during the remote VT-3 examination of the vessel interior. The LRA also states that the indication was evaluated and additional volumetric and surface examinations were performed for better characterization. The LRA further states that the indication was determined to be acceptable as is.

During the audit, the staff noted that the applicant's reactor vessel bottom head region has at least two indications of cladding degradation (detected in RFOs 13 and 15 respectively), as indicated in LRA Section 4.7.3. Therefore, the staff needed to clarify how many total indications of reactor vessel cladding degradation have been detected. In addition, the staff noted that the LRA does not clearly provide the following information: (a) the root cause analysis and

corrective action for the cladding indications, (b) the previous inspection results to identify any change in the size and depth of the cladding indications, and (c) the inspection method and frequency to manage the degradation of the cladding and reactor vessel as well as the technical basis for the adequacy of the inspection method and frequency.

By letter dated July 18, 2012, the staff issued RAI B2.1.5-4 requesting the applicant to confirm how many total indications of reactor vessel cladding degradation have been detected. The staff also requested that the applicant describe the results of the root cause analysis for the cladding degradation (i.e., what caused the cladding degradation), and to confirm whether cladding degradation continues to progress. In addition, the staff requested that the applicant describe any corrective action taken to prevent additional cladding and vessel degradation and describe why the corrective action was adequate to manage degradation of cladding and reactor vessel.

Furthermore, the staff requested that the applicant provide the following information regarding the previous inspection results for each of the cladding indications: (a) clarification as to whether any of these cladding indications is associated with cracking, leakage, or other degradation of reactor vessel bottom head penetrations, (b) the results (size and depth data) of the previous inspections performed after the initial detections of cladding indications, including any change in the size and depth of the cladding indications in comparison with the initial size and depth that were detected for the first time, and (c) the comparison between the most recent depth data with the thickness of the non-degraded cladding and the thickness of the non-degraded reactor vessel steel (excluding the cladding), respectively.

The staff also requested that the applicant describe the inspection method and frequency of the subsequent inspections of the cladding indications as defined in the applicant's program and describe the technical basis for why the inspection method and frequency are adequate to manage the degradation of cladding and reactor vessel.

In its response dated August 21, 2012, the applicant stated that the only indications are the two indications that were previously documented during RFO 13 (spring 2004) and RFO 15 (spring 2007), and both indications were determined to be the result of damage during fabrication or construction. The applicant also indicated that a root cause analysis was performed for the indication identified during RFO 13, and the direct cause for the indication on the cladding is excessive grinding or buffing of the cladding. The applicant further indicated that as described in its corrective action documents, the exposure of the low alloy carbon steel base metal was caused by (1) grinding during repair activities, (2) grinding during the completion of the cladding application in the lower dome-to-torus weld, or (3) buffing or smoothing performed following onsite vessel installation. In addition, the applicant stated that the cause of the indication identified during RFO 15 is most likely grinding or similar activities during vessel construction. The applicant further stated that no corrective actions were taken to prevent additional occurrence of the cladding damage because the cladding indications were determined to be due to the fabrication or construction activities.

The applicant also stated that stainless steel is highly resistant to erosion and other areas of the vessel seeing higher flow rates do not show similar indications. The applicant further stated that there is no metal-to-metal contact in this area of the vessel; therefore, rubbing is not the cause. Also, there are grinding or flapper wheel marks around the indication, which suggests that these indications are from fabrication.

In its response regarding the previous inspection results, the applicant stated that neither indication is associated with cracking, leaking, or other degradation of reactor vessel bottom

head penetrations. The applicant also stated that no further inspections have been done to the cladding indications as of RFO 18 in 2011. The applicant stated that the indications were planned to be inspected during RFO 18, but difficulties removing the lower internals prevented the inspections from taking place.

In addition, the applicant indicated that based on the applicant's drawings E-11173-171-004 and E-11173-171-005, the inside radius of the reactor vessel shell is 88.16 in. and the reactor vessel wall thickness is 5.38 in., including the cladding (0.22 in.). The applicant further stated that the degraded cladding area dimensions (length x height x depth) are 1.5 inch x 0.625 inch x 0.28 inch and 0.53 inch x 0.3 inch x 0.10 inch, per UT reports from Wesdyne.

In its response regarding the applicant's inspection schedule for the degraded cladding areas, the applicant stated that the indications are inspected opportunistically when the core barrel is pulled during an RFO, such as for ASME category B-N-3 examinations. The applicant also stated that the prior RF 13 and 15 evaluations of the indications determined that there is no growth expected and, based on these evaluations, the opportunistic inspections will be used to manage the degradation of the cladding and RPV.

In its review, the staff found that the applicant's response regarding the total number of the cladding indications and the root cause analysis is acceptable because the applicant clarified that only two indications of reactor vessel cladding degradation have been identified, and the results of the applicant's root cause analysis determined that the direct cause of the indications is excessive grinding or buffing of the cladding (i.e., not due to aging degradation).

However, the staff identified a concern related to the applicant's opportunistic inspections of the cladding indications. Specifically, the applicant's opportunistic inspections do not specify the inspection frequency or inspection method. In addition, the staff needed justification for why the applicant's inspections of the indications are not identified as a program enhancement. The staff also needed further clarification for why the size (1.5 inch x 0.625 inch) of the first indication discovered in 2004 was different from the size described in LRA Section 4.7.3 (1.5 inch x 0.75 inch). The staff needed further clarification for why the conservative total depth for the indications is 0.28 inch rather than 0.36 inch, if the base metal reduction for the indication discovered in 2004 is assumed to be 0.14 inch beyond the reactor vessel cladding (0.22-inch nominal thickness). By letter dated October 12, 2012, the staff issued RAI 2.1.5-4a requesting the applicant to provide clarification on the issues above. The staff further requested that the applicant identify the inspection methods that will be used to manage loss of material of the degradation indications and justify why the opportunistic inspections without a specific inspection frequency are sufficient to manage the aging effect. In addition, the staff requested that the applicant justify why the applicant's inspections of the degradation indications are not identified as a program enhancement.

In its response dated November 8, 2012, the applicant stated that the previous reference to 0.65 inch for the width of the first indication (discovered in 2004) was an error and corrective action was taken to clarify that the correct width value is 0.75 inch. The applicant also clarified that this corrective action did not affect the validity of the corrosion rate calculations. The applicant further stated that grinding during reactor vessel fabrication was the likely cause of the 2004 indication, which reduced the cladding thickness to 0.14 inch at the edge of the indication. In addition, the applicant clarified that the actual measured depth of the first indication was a total of 0.14-inch and therefore, it is conservative to assume that the base metal depth is reduced by 0.14-inch in addition to the 0.14-inch cladding thickness, resulting in a conservative degradation depth of 0.28 inch. In its review, the staff found this portion of the applicant's

response acceptable based on the applicant's clarifications regarding the correct width value (0.75 inch) of the indication and the actual total degradation depth (0.14 inch) in the vicinity of the indication, which is less than the applicant's conservative value (0.28 inch).

In its response, the applicant also clarified that the VT-3 examinations will be performed at least once every 10 years. The applicant further clarified that a program enhancement is not necessary since these visual examinations are consistent with the requirements of ASME Code Section XI, Table IWB-2500-1, Examination Category B-N-1 and the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. In its review regarding the inspection frequency and program enhancement, the staff found this portion of the response acceptable because the applicant clarified that the VT-3 visual examinations will be performed periodically to monitor the degradation indications and these examinations are consistent with the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program.

However, the staff noted the VT-3 examinations are not capable of monitoring the depths of the indications in the reactor vessel and the applicant's response to RAI B2.1.5-4a does not clearly address how its examinations will monitor the depths and depth-related conditions of the indications for the period of extended operation. By letter dated January 30, 2013, the staff issued RAI 2.1.5-4b, requesting the applicant clarify how the applicant will monitor the depths and depth-related conditions of the indications. The staff also requested that such monitoring activities be clearly described in the summary description of the program in the FSAR supplement.

In its response dated February 14, 2013, the applicant stated that during the upcoming RFO (spring, 2013), an ultrasonic examination of each indication in the reactor vessel wall is planned and surface profile data will be collected in the area of the indication and the surrounding cladding. The applicant also stated the following:

> [c]onsistent with the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD [Program], future thickness measurements of the reactor vessel wall indications in the reactor vessel lower head will be determined by: (a) obtaining surface profile data of the indications and surrounding cladding using an ultrasonic examination from the inside of the reactor vessel, (b) using an ultrasonic examination from the outside of the reactor vessel, or (c) using remote mechanical gages inside the reactor vessel.

In addition, the applicant revised LRA Appendix A1.1 (FSAR supplement for the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program) and LRA Section B2.1.1, consistent with its response.

Based on its review, the staff finds the applicant's response acceptable because the applicant clarified that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program will perform depth measurements of the indications using an examination method that is capable of measuring the depths, consistent with ASME Code Section XI, and the applicant appropriately revised the FSAR supplement to summarize the depth measurement activities. Therefore, the staff's concerns described in RAIs B2.1.5-4, B2.1.5-4a and B2.1.5-4b are resolved.

Based on its audit and review of the application, and review of the applicant responses to RAIs B2.1.5-3, B2.1.5-4, B2.1.5-4a, and B2.1.5-4b, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and that implementation of the program has resulted in the applicant taking corrective action. In addition,

the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.M11B was evaluated.

FSAR Supplement. LRA Section A1.5 provides the FSAR supplement for the Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-induced Corrosion in Reactor Coolant Pressure Boundary Components Program. The staff reviewed this FSAR 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 FSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary 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 function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff reviewed the FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.5 PWR Vessel Internals

Summary of Technical Information in the Application. LRA Section B2.1.6 describes the new PWR Vessel Internals Program as consistent with GALL Report AMP XI.M16A, "PWR Vessel Internals." The LRA states that the PWR Vessel Internals Program manages aging in those Callaway reactor vessel internal (RVI) components that provide core structural support for the reactor.

The LRA states that the PWR Vessel Internals Program manages the following aging effects: (a) cracking induced by either SCC, PWSCC, irradiation-assisted SCC, fatigue or cyclical loading; (b) loss of material induced by wear; (c) loss of fracture toughness induced by either neutron irradiation embrittlement or thermal aging embrittlement; (d) changes in component dimensions induced by void swelling, irradiation-induced growth, distortion or deflection; and (e) loss of preload induced by thermal and irradiation-enhanced stress relaxation and creep. LRA Section 3.1.2, "Results," and LRA Table 3.1.2-1, "Reactor Vessel, Internals, and Reactor Coolant System – Summary of Aging Management Evaluation – Reactor Vessel and Internals," provide additional information in support of the PWR Vessel Internals Program.

LRA Table 3.1.2-1 identifies that RVI components are exposed to an external reactor coolant environment; and that with the exception of the RVI clevis inserts and insert bolts and RVI radial support keys, the RVI components are made from stainless steel materials. LRA Table 3.1.2-1 identifies that the RVI clevis inserts and insert bolts and RVI radial support keys are made from nickel alloy materials.

The LRA states that the PWR Vessel Internals Program implements the guidance of EPRI report No. 1016596, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guideline (MRP-227, Revision 0)," and EPRI report No. 1016609, "Inspection Standard for PWR Internals (MRP-228, Revision 0)." The LRA also states that the PWR Vessel Internals Program has addressed those plant-specific action items, conditions, and limitations that were identified in the NRC's safety evaluation for the MRP-227 report. The LRA further states that the PWR Vessel Internals Program inspects the following categories of RVI components:

- inspections of the "primary category" components in accordance with the components and inspection criteria specified in Table 4-3 of the MRP-227 report
- inspections of "expansion category" components in accordance with the components and inspection criteria specified in Table 4-6 of the MRP-227 report
- inspections of RVI components falling into the "existing program" category in accordance with existing programmatic requirement or recommended criteria, such as ASME Code Section XI, Examination Category B-N-3 requirements for core support structure components or LRA AMP B2.1.22, "Flux Thimble Tube Inspection," for inspections of the bottom-mounted instrumentation flux thimble tubes

The LRA states that the PWR Vessel Internals Program inspects these components using either visual VT-3 or enhanced visual EVT-1 inspection methods or ultrasonic volumetric inspection methods. The LRA also states that the remaining RVI components fall into a fourth "No Additional Measures" category and that the components in this category are not subject to the EPRI MRP's augmented inspection recommendations in MRP-227-A. The LRA further states that the reactor vessel integral attachments are inspected in accordance with LRA AMP B2.1.1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD."

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1 through 6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M16A. In addition, the staff observed that the PWR Vessel Internals Program is based on the approved version of the MRP-227 report (i.e., EPRI MRP Technical Report No. MRP-227-A [TR MRP-227-A], which was formally issued on January 9, 2012, and may be accessed in Agencywide Documents Access and Management System [ADAMS] Accession Nos. MI12017A191, ML12017A193, ML12017A194, ML12017A196, and ML12017A197).[1] The NRC endorsed the methodology in TR MRP-227-A in the NRC's revised safety evaluation (SE, Revision 1) on the methodology dated December 16, 2011 (ML11308A770).

The staff also noted that in MRP-227-A, the EPRI MRP had indicated that the program would be implemented in accordance with the "confirmation process" and "administrative controls" program elements specified in the MRP-227-A report and that these controls would be implemented in accordance with the applicant's process for implementing the methodology in Nuclear Energy Institute (NEI) Technical Report (TR) No. NEI 03-08, Revision 2, "Guideline for Management of Materials Issues," dated January 2010. The staff also noted that the MRP-227-A report indicated that the applicant's implementation of the "corrective actions" program element and disposition of relevant plant-specific or applicable generic operating experience would be implemented in accordance with Section 7 of the MRP-227-A report and the applicant's NEI 03-08 process. Therefore, the staff also included a review of the "corrective actions," "confirmation process," and "administrative controls" program elements during its audit review of the applicant's PWR Vessel Internals Program.

The staff noted that Section 1 of the MRP-227-A report states that, for all RVI components that are defined in the PWR applicant's CLB as core support structures components, the applicant must meet the ISI requirements of ASME Code Section XI, Examination Category B-N-3.

[1] The MRP-227-A report includes the staff's safety evaluation that was issued in approval of the report's augmented inspection methodology for PWR RVI components.

The staff noted that the MRP-227-A report indicates that this applies to all RVI components that are classified as RVI core support structure components for the applicant's CLB independent of whether the components have been classified and designated as "No Additional Measures" components in the MRP-227-A report methodology or were inadvertently omitted as being within the scope of the generic analysis for Westinghouse RVI designs in the MRP-227-A report. The staff also noted that the methodology in the MRP-227-A report cannot be used as the basis for establishing which RVI components are ASME Code Section XI, Examination Category B-N-3 components for the CLB. The staff's review of the applicable AMR items for the RVI components in the Callaway design, as documented in SER Sections 3.1.2.1.2 and 3.1.2.1.3, confirms that the applicant will be fulfilling its obligations for complying with these ASME Code Section XI inservice inspection (ISI) requirements.

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.

The staff noted that Table 4-3 of the MRP-227-A report identifies that the flexures in the thermal shield assembly are "Primary Category" RVI components for Westinghouse plants that will be implementing the MRP-227-A recommendations. During its audit, the staff noted that the basis document for the applicant's PWR Vessel Internals Program stated that the RVI design does not include thermal shield flexures. Instead, the staff noted, the basis document stated that the RVI design includes neutron shield panels in lieu of thermal shield flexures. However, the staff noted that LRA Table 4.3-5, "Reactor Internals Design Basis Fatigue Analysis Results," identifies that the applicant performed a fatigue analysis on the thermal shield flexures and calculated cumulative usage factor (CUF) value of 0.978 for the components.

By letter dated July 18, 2012, the staff issued RAI B2.1.6-1, requesting that the applicant address this issue. In this RAI, the staff asked the applicant: (a) to justify why the PWR Vessel Internals Program would not implement inspections of the flexures consistent with the MRP-227-A recommendations, if the plant design includes thermal shield flexures; or (b) if the design does not include thermal shield flexures, to identify the RVI component or components that serve the same intended function as that for thermal shield flexure components in the generic Westinghouse design that was evaluated in the MRP-227-A report, and to justify why the alternative components would not need to be inspected in accordance with the recommendations in the MRP-227-A report, or as an augmentation of the applicant's inspection protocols for the PWR Vessel Internals Program.

The applicant responded to RAI B2.1.6-1 in a letter dated August 21, 2012 (ML12235A467 for the Cover Letter and ML12235A468 for the enclosures containing the RAI response and LRA amendments for LRA Amendment 7). In its response, the applicant stated that the thermal shield and thermal shield flexures described in MRP-227-A are not applicable to the Callaway design. The applicant stated that, instead, a neutron shield panel assembly is used to achieve the same neutron shielding function as do thermal shield flexures that are included in the designs of some other Westinghouse-designed PWRs. The applicant stated that a neutron shield panel assembly consists of four panels that are bolted and pinned to the outside of the core barrel. The applicant stated that the neutron shield panels are used to reduce the neutron fluence exposure to the reactor vessel welds and that the neutron shield panels and bolting are screened out as Category A in Table 7-2 of MRP-191, "Materials Reliability Program: Screening, Categorizing, and Ranking of Reactor Internals of Westinghouse and Combustion Engineering PWR Designs (MRP-191)," dated November 2006. The applicant further stated that, as defined in MRP-191, Section 2.0, the ASME Code Section XI, Category B-N-3 ISI visual inspections will be performed on these components, even though (as clarified in the response to

RAI B2.1.6-3) the thermal shield panels are not strictly defined as ASME Section XI, Examination Category B-N-3 components. The applicant also clarified that the CUF value provided in the LRA is that for the neutron shield panel bolts, and not for thermal shield flexures.

The staff noted that, as part of its response to RAI B2.1.6-1, the applicant amended the LRA to reflect this change. The staff confirmed that the applicant appropriately amended LRA Table 4.3-5 to state that the CUF value was calculated for the neutron panel bolts, and not the thermal shield flexures. The staff also confirmed that, in the applicant's letter of October 24, 2012 (ML12299A248 for the Cover Letter, ML12299A249 for Enclosure 1 containing the RAI responses, and ML12299A250 for Enclosure 2 containing the associated LRA amendments for LRA Amendment 13), the applicant included the applicable AMR Item for managing cracking and loss of material due to wear in the thermal shield panels and credited the ASME Section XI, Subsection IWB, IWC, and IWD Program as the basis for managing the applicable aging effects for the components during the period of extended operation. The staff finds the applicant's basis for managing cracking in the neutron shield panels acceptable because: (a) the applicant has used its CLB to define the appropriate aging management basis for managing cracking in the neutron shield panels and (b) the applicant will appropriately be using its ASME Section XI, Subsections IWB, IWC, and IWD Program to perform VT-3 examinations of the neutron shield panels, even though this type of basis is not referenced in the MRP-227-A report for these components. The staff's request in RAI B2.1.6-1 is resolved.

The staff noted that Table 4-9 in Technical Report No. MRP-227-A (TR MRP-227-A) identifies that the upper support rings or skirts in the upper internal assemblies of Westinghouse reactor designs are "Existing Program" RVI components and that the components will be inspected in accordance with the applicable ASME Section XI inservice inspection (ISI) requirements. During the audit, the staff noted that the program basis document for the applicant's PWR Vessel Internals Program did not include proposed inspections of an upper support ring or skirt in upper internals assembly of the plant. It was not clear to the staff whether the RVI design at Callaway included an upper support ring or skirt.

By letter dated July 18, 2012, the staff issued RAI B2.1.6-2, requesting that the applicant address this issue. In this RAI, the staff asked the applicant to: (a) justify why the PWR Vessel Internals Program would not implement inspections of the component consistent with the MRP-227-A recommendations if the plant design does include an upper support ring or skirt, or (b) if the design does not include an upper support ring or skirt, to identify the RVI component that serves the same intended function as that for upper support ring or skirt components in the generic Westinghouse design that was evaluated in the MRP-227-A report, and to justify why the alternative component would not need to be inspected in accordance with the applicant's PWR Vessel Internals Program.

The applicant responded to RAI B2.1.6-2 in a letter dated August 21, 2012 (ML12235A467 for the Cover Letter and ML12235A468 for the enclosures containing the RAI response and LRA amendments for LRA Amendment 7). In its response, the applicant stated that the plant design does include an upper support skirt, which is a subcomponent of the upper support plate. The applicant stated that the LRA has been amended to include the upper support skirt as an "Existing Program" component consistent with the MRP-227-A recommendations. The staff confirmed that, in the letter of August 21, 2012, the applicant appropriately amended LRA Table 3.1.2-1 to include an AMR item on cracking of the RVI upper support skirt, and that the applicant is crediting the PWR Vessel Internals Program's ASME Code Section XI "Existing Program" activities (along with the Water Chemistry Program) to manage cracking in the support skirt. The staff finds the applicant's basis for managing cracking in the upper support

skirt acceptable because the applicant's basis is consistent with the recommendations of MRP-227-A for "Existing Program" components and the upper support skirt will be examined in accordance with the existing ASME Code Section XI ISI requirements. The staff's request in RAI B2.1.6-2 is resolved.

The staff noted that Section 4.4.3 and Table 4-9 in TR MRP-227-A list those "Existing Program" components that are identified as ASME Code Section XI "Core Support Structure" components. The staff also noted that the MRP-227-A report states that these components are examined with the ISI requirements in ASME Code Section XI, Table IWB-2500-1, for removable core support structure components (i.e., Examination Category B-N-3 components). However, during the audit, the staff noted that the program basis documents for the applicant's PWR Vessel Internals Program did not identify which RVI components are designated as ASME Code Section XI, Examination Category B-N-3 components for the Callaway CLB. In addition, the applicant did not explain: (a) whether the method of performing the VT-3 visual examination in accordance with this ASME Section XI examination category would actually achieve coverage of those RVI components that were designated as ASME Code Section XI, Examination Category B-N-3 components for the Callaway facility, and (b) whether there were any additional RVI components that were identified as ASME Code Section XI, Examination Category B-N-3 components for the Callaway CLB, but that were not assumed in Table 4-9 of the generic MRP-227-A report.

By letter dated July 18, 2012, the staff issued RAI B2.1.6-3, requesting that the applicant provide additional clarifications on the ASME Code Section XI, Examination Category B-N-3 criteria that are used for the plant's CLB. Specifically, the staff asked the applicant: (a) to identify all RVI component locations that are designated as ASME Code Section XI, Examination Category B-N-3 components; (b) to identify those additional component locations that were ASME Code Section XI, Examination Category B-N-3 components for the Callaway CLB but that were not assumed as ASME Code Section XI, Examination Category B-N-3 components in Table 4-9 of the MRP-227-A report, and to identify those aging effects applicable to the additional ASME Section B-N-3 components for the facility; and (c) based on previous ASME Code Section XI examinations of B-N-3 component surfaces, to clarify and justify whether the implementation of VT-3 examinations of the B-N-3 components surfaces would actually achieve inspection coverage of those components that are designated as ASME Code Section XI B-N-3 components for the Callaway CLB.

The applicant responded to RAI B2.1.6-3 in a letter dated August 21, 2012 (ML12235A467 for the Cover Letter and ML12235A468 for the enclosures containing the RAI response and LRA amendments for LRA Amendment 7). In its response, the applicant stated that all the RVI components listed in LRA Table 2.3.1-1, with the exception of the "RVI Neutron Shield Panel" and "RVI BMI Flux Thimbles," are designated as ASME Code Section XI, Examination Category B-N-3 components and that these components are ASME Code Section XI "Existing Program" components for the AMP. The applicant also stated that it did not identify any aging effects that are not assumed in MRP-227-A, Table 4-9. The applicant stated that the VT-3 examinations manage cracking and loss of material due to wear, which are aging effects assumed in Table 4-9 of MRP-227-A. The applicant further stated that as described in ASME Code Section XI Paragraph IWB-3520.2, its VT-3 examination method looks for evidence of loss of component integrity at bolted or welded connections, loose or missing parts, debris, corrosion, wear, or erosion in the components.

The applicant stated that the VT-3 examination is capable of monitoring the aging effects addressed in MRP-227-A, Table 4-9, for "Existing Program" components. The staff finds this

aging management basis, as supplemented in the applicant response to RAI B2.1.6-3, to be acceptable because the basis is consistent with (a) the applicant's CLB for complying with 10 CFR 50.55a requirements and (b) the basis in Section 1 of the MRP-227-A report that requires the applicant to examine all RVI components identified as ASME Code Section XI, Examination Category B-N-3 components. The staff also finds that the applicant may use either the PWR Vessel Internals Program or the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program to implement the applicable ASME Code Section XI ISI requirements for these components. The staff's concern described in RAI B2.1.6-3 is resolved.

The staff noted that, by letter dated April 23, 2014 (ADAMS ML14114A113 for the Cover Letter and ML14114A110 for the enclosure containing the LRA amendment in LRA Amendment 34), the applicant identified that the design of the RVI components at Callaway does not include baffle-edge bolts in the plant's core baffle assembly. The staff reviewed the plant design document and verified that the design of the plant's core baffle assembly does not include baffle-edge bolts. As a result, the staff noted that these components are not within the scope of the applicant's PWR Vessel Internals Program and that the "Primary Category" inspection recommendations for inspecting Westinghouse-designed baffle-edge bolts in TR MRP-227-A do not apply to the Callaway CLB. Based on this review, the staff reviewed the applicant's claim and LRA amendment and finds it acceptable because the staff has confirmed that the RVI design does not include baffle-edge bolts.

Based on its audit of the PWR Vessel Internals Program and review of the applicant's responses to RAIs B2.1.6-1, B2.1.6-2, and B2.1.6-3, the staff finds that program elements 1 through 9 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M16A, with the exceptions that have been noted, discussed, and accepted earlier in this evaluation.

The staff's review of the applicant's bases for resolving applicable Applicant/Licensee Action Items on the methodology in TR MRP-227-A is given in the following subsection.

Review of License Renewal Applicant Action Items. In the staff's revised Safety Evaluation (revised SE [ADAMS Accession No. ML11308A770]) for Topical Report MRP-227-A, the staff issued the following license renewal applicant or licensee action items (A/LAIs):

(1) Applicability of Failure Modes, Effects, and Criticality Analyses (FMECA) and Functionality Analysis Assumptions

(2) PWR Vessel Internal Components within the Scope of License Renewal

(3) Evaluation of the Adequacy of Plant-Specific Existing Programs

(4) Babcock and Wilcox (B&W) Core Support Structure Upper Flange Stress Relief

(5) Application of Physical Measurements as part of I&E Guidelines for B&W, CE, and Westinghouse RVI Components

(6) Evaluation of Inaccessible B&W Components

(7) Plant-Specific Evaluation of CASS Materials

(8) Submittal of Information for Staff Review and Approval

The above A/LAIs represent plant-specific aging management conditions to be addressed by the applicant as part of its program element criteria for implementing the PWR Vessel Internals Program.

The staff noted that NEI TR No. NEI-95-10, Revision 6, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule," dated June 2005, identifies that Appendix C of the LRA is the appropriate place for providing responses to these A/LAIs. However, the staff noted that Appendix C of the LRA did not include the applicant's responses to the A/LAIs on MRP-227-A because the LRA was prepared and submitted to the NRC prior to the NRC's issuance of the revised SE on MRP-227-A report. By letter dated September 25, 2012, the staff issued RAI B2.1.6-4, requesting the applicant to either provide the basis for omitting responses to the applicable A/LAIs on MRP-227-A or to amend its LRA to include the appropriate responses to the applicable A/LAIs on MRP-227-A.

The applicant responded to RAI B2.1.6-4 in a letter dated October 24, 2012. In its response, the applicant stated that it will provide the specific responses to the A/LAIs on the MRP-227-A methodology in LRA Appendix C. The applicant stated that the LRA Appendix C supplement containing the A/LAI response bases will be provided consistent with Commitment No. 4 in LRA Table A4-1, in which the applicant commits to implementation of the PWR Vessel Internals Program within 24 months after the date of the EPRI MRP's issuance of the MRP-227-A report (i.e., January 9, 2012, as submitted in ADAMS Accession Nos. ML12017A193, ML12017A194, ML12017A196, ML12017A197). The applicant also stated that Commitment No. 4 includes a commitment to submit the Callaway RVI inspection plan, as recommended in A/LAI #8, Item (2) of the NRC's revised SE on the MRP-227-A methodology within 24 months after the date of the issuance of the MRP-227-A report.

In its response to RAI B2.1.6-4, the applicant also provided the summaries of its response bases to these A/LAIs. The staff reviewed these A/LAI response summaries to determine which of the A/LAI response bases could be resolved and which of the applicant's A/LAI response bases would require further RAIs. However, the staff noted that NRC Regulatory Information Summary (RIS) 2011-07, "License Renewal Submittal Information For Pressurized Water Reactor Internals Aging Management," dated July 21, 2011 (ML111990086), provides guidance on the specific process that license renewal applicants or licensees would use to submit RVI aging management programs or inspection plans to the NRC for approval. The staff noted that, for plants like Callaway which would be submitting their LRAs in accordance with the guidelines in Revision 2 of the GALL Report (i.e., RIS 2011-07 Category D plants), the RIS identifies that the applicant is expected to submit an AMP for its PWR vessel internals that is consistent with MRP-227-A report for staff approval. Therefore, the staff noted that the applicant should resolve the A/LAIs on the MRP-227-A methodology as part of the staff's review of the PWR Vessel Internals Program. The staff's evaluations of the applicant's A/LAI response bases are given in the italicized, underlined subsections that follow.

Evaluation of the Response Summary to A/LAI #1. In A/LAI #1, the staff recommended that applicants applying the MRP-227-A methodology should describe the process that would be used to determine whether the assumptions used to develop the methodology are bounding for the design of the RVI components at their PWR facility. In response to A/LAI #1, the applicant stated that the applicability of FMECA and Functionality Analysis Assumptions Applicability assumptions identified in MRP-227-A Section 2.4 are identified in the program element 1 discussion of the applicant's basis document for its PWR Vessel Internals Program.

During the audit of the applicant's PWR Vessel Internals Program, the staff noted that the applicant's basis document for the AMP addressed why the CLB for Callaway was considered to be bounded by the following assumptions used to develop the MRP-227-A: (a) fuel loading assumptions, (b) base-load operation assumptions, and (c) RVI design change assumptions.

Specifically, with regard to fuel loading patterns, the staff noted that the MRP-227-A report assumes a 60-year licensed life for the facility and that the reactor for the facility will operate at normal neutron leakage patterns (i.e., leakage rates) from the reactor core for the first 30 years of that operating term, followed by 30 years of operation with low neutron leakage patterns.

In regard to plant operations, the staff also noted that the MRP-227-A report assumes that the plant operates using base load operations (i.e., the plant operates at fixed power levels and does not vary power on a calendar or load demand schedule) and the methodology assumes that the licensee for the facility has only implemented those RVI design changes that were recommended in industry generic communications or in vendor recommendations.

In response to these assumptions, the applicant clarified that the CLB for the RVI components at Callaway is bounded by the assumptions because the plant has operated with low neutron leakage patterns for all operating cycles other than operating Cycle 1 (during which the plant operated with normal neutron leakage rates). The applicant also stated that the Callaway facility is a base-load facility and that the design basis for the RVI components only implemented those RVI design modifications that were recommended by Westinghouse as the nuclear steam supply system vendor for the facility (e.g., the decision to replace the control rod guide tube (CRGT) split pins, as recommended by Westinghouse). The staff noted that the applicant's response was either consistent with the assumptions stated in the MRP-227-A report or bounded by them. However, the staff also noted that the FMECA and Functionality Analysis results that were established in the supporting EPRI MRP-191 report and used to develop the inspection and evaluation (I&E) recommendations for Westinghouse-designed RVI components in the MRP-227-A report were based on conformance with particular upper-bound component stress, temperature, and neutron fluence threshold values for these components. The staff noted that the applicant did not provide any discussion on whether the actual stress, temperature, and neutron fluence values for the design of the RVI components at Callaway were actually bounded by the threshold values for these parameters, as assumed in the MRP-191 report for the same components.

By letter dated December 17, 2012, the staff issued RAI B2.1.6-4a, requesting, in part, that the applicant provide additional information and clarifications on how it would resolve this aspect of the request in A/LAI #1. The staff identified this issue as Open Item B2.1.6-1, Part (a).

The applicant responded to RAI B2.1.6-4a in a letter dated January 24, 2013. In its response, the applicant stated that it was addressing the request and amending Commitment No. 4 in LRA FSAR supplement Table A4-1 to indicate that the resolution of A/LAI #1 would be addressed as part of the applicant's commitment and basis for implementing of the Reactor Vessel Internals Program and that the following actions would be taken relative to this commitment:

> Each applicant/licensee is responsible for assessing its plant's design and operating history and demonstrating that the approved version of MRP-227 is applicable to the facility. Each applicant/licensee shall refer, in particular, to the assumptions regarding plant design and operating history made in the FMECA and functionality analyses for reactors of their design (i.e., Westinghouse, CE, or B&W) which support MRP-227 and describe the process used for determining plant-specific differences in the design of their RVI components or plant operating conditions, which result in different component inspection categories. The applicant/licensee shall submit this evaluation for NRC review and approval as part of its application to implement the approved version of MRP-227.

The staff did not find the applicant's response to RAI B2.1.6-4a (as made relative to the resolution of A/LAI #1) to be acceptable because the applicant did not submit any basis to demonstrate that the methodologies for Westinghouse components in the MRP-191 and MRP-227-A reports were applicable and bounding for the design of the RVI components at the Callaway facility and because Callaway is categorized as a RIS 2011-07 Category D plant.

However, since a number of industry licensees (including Ameren Missouri) were establishing their efforts to resolve the NRC's actions requested in A/LAI #1, the staff held a series of proprietary and public meetings with members of Westinghouse Electric Company (Westinghouse), the EPRI MRP, and NRC-licensed utilities in order to: (a) address the NRC's regulatory bases for resolving this action item, (b) encourage the development of a generic approach that could be used to resolve the requests in A/LAI #1, and (c) establish a path for receiving comprehensive and consistent utility responses that would address the applicability of the MRP-227-A methodology for PWRs having either Westinghouse or Combustion Engineering RVI designs. As a result of these discussions, the staff agreed that a generic approach could be applied as a basis for resolving the action requests in A/LAI #1 if an applicant addressing the action item would respond to the following questions that relate to the unit's reactor design:

Question 1: Does the plant have any nonwelded or bolted austenitic stainless steel (SS) components with 20 percent cold work or greater, and, if so, do the affected components have operating stresses greater than 30 ksi? (If both conditions are true, additional components may need to be screened in for stress corrosion cracking (SCC).)

Question 2: Does the plant have atypical fuel design or fuel management that could render the assumptions of MRP-227-A, regarding core loading/core design, nonrepresentative for that plant?

By a letter dated October 14, 2013, the EPRI MRP issued EPRI MRP Letter 2013-025, "MRP-227-A Applicability Guidelines for Combustion Engineering and Westinghouse Pressurized Water Reactor Designs" (ML13322A454), which provided the industry licensees with a nonproprietary, generic methodology for responding to the two questions on A/LAI #1. The staff noted that, in regard to resolving the request in Question 1, the EPRI MRP letter provides the licensees with guidance for assessing whether the RVI components at their plant, other than those identified in the generic evaluation, would have the potential for cold work greater than 20 percent, and if so, whether the operating stresses for those components would be in excess of 30 ksi. Under this basis, nonwelded or bolted RVI components that have cold-work and stress levels in excess of these criteria would need to be considered for augmented inspections or evaluations under the MRP's recommended protocols in EPRI MRP Letter 2013-025.

With respect to resolving Question 2, the staff noted that EPRI MRP Letter 2013-025 provided specific quantitative criteria that would allow a licensee to assess whether a particular plant has atypical fuel design or fuel management. For a Westinghouse-design plant like Callaway, the threshold criteria for assessing fuel load assumptions in EPRI MRP Letter 2013--025 and used to demonstrate conformance with the fuel loading assumptions in the MRP-227-A report are:

(1) The heat generation rate must be less than or equal to 68 watts/cm^3.

(2) The maximum average core power density must be less than 124 watts/cm^3.

(3) The distance from the top of the active fuel to upper core plate must be greater than 12.2 in.

Therefore, the staff issued a second followup RAI that was based on conformance with the EPRI MRP's generic methodology for resolving A/LAI #1, as given in EPRI MRP Letter 2013-025.

By letter dated December 2, 2013, the staff issued RAI B2.1.6-4d (Followup), Parts a. and b., to the applicant in order to request responses to these questions. In RAI B2.1.6-4d, Part a., the staff asked the applicant to clarify whether the design of RVI components at Callaway included any nonwelded or bolted austenitic stainless steel components whose design stresses are greater than 30 ksi and whose materials were cold worked to 20 percent or greater cold-work levels. If so, the staff asked the applicant to justify why the current I&E bases in MRP-227-A report are considered to be adequate for managing cracking or other applicable aging effects in these nonwelded components. Otherwise, the staff asked the applicant to clarify and justify how the MRP-227-A report's I&E bases for these RVI components would be adjusted as part of the applicant's basis for responding to A/LAI #2.

In RAI B2.1.6-4d (Followup), Part b., the staff asked the applicant to clarify whether Ameren has ever used atypical fuel designs or fuel management protocols that could make the assumptions in MRP-227-A for core design, core loading, and core leakage patterns nonrepresentative for the Callaway RVI design, including those that might have been approved for the facility in accordance with the NRC's 10 CFR 50.90 process for reviewing a power uprate/power change license amendment request. If so, the staff asked the applicant to justify why the current I&E bases in MRP-227-A report were considered to be sufficient for managing cracking and other applicable aging effects in the plant's RVI components based on the actual fuel loading patterns and fuel power conditions that were approved in the CLB. Otherwise, the staff asked the applicant to clarify and justify how the MRP report's I&E bases for these RVI components would be adjusted as part of the applicant's basis for responding to A/LAI #2.

The applicant responded to RAI B2.1.6-4d, Parts a. and b., in a letter dated February 5, 2014 (ML14036A360 for the Cover Letter and ML14036A359 for the enclosed responses to the RAI). On March 28, 2014, the applicant submitted a supplemental, copyrighted response to RAI B2.1.6-4d, Part a. (ML14087A092 for the Cover Letter and ML14087A092 for the enclosed supplemental response to RAI B2.1.6-4d, Part a.), that superseded the previous response to this RAI part in the applicant's letter of February 5, 2014.

In its response to RAI B2.1.6-4d, Part a., the applicant indicated that it used the EPRI MRP-191 report bases and EPRI MRP Letter 2013-025 guidelines (ML13322A454) as the bases for comparing the stress levels of the RVI components at Callaway to those evaluated for the generic Westinghouse design plant that was assumed and assessed in the EPRI MRP-227-A and MRP-191 reports. The applicant stated that it contracted with Westinghouse to gather the necessary information needed to verify whether the stress levels in the RVI components and amount of cold work in the materials used to fabricate the RVI components were within the bounds assessed for these components in the MRP-191 report and to assist the applicant in its development of the response to this RAI.[2]

[2] The staff acknowledges that its summary of the applicant's response to RAI B.2.1.6-4d, Part a., is a summary of the copyrighted response prepared for the applicant by the Westinghouse Electric Company and that the Westinghouse Electric Company has designated that the specific response to the RAI is copyrighted material that is copyright protected in accordance with the following Westinghouse designation:

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The applicant indicated that none of the RVI components made from CASS or hot-formed or annealed austenitic stainless steel materials had cold-work levels in excess of 20 percent because the acceptable levels of cold work were addressed through conformance with the material specifications used to fabricate the components. The applicant stated that these levels of cold work were ensured through implementation of controlled fabrication processes that were used to make the components. The applicant also indicated that, for those fastened (bolted) or welded RVI components in which the applicant conservatively concluded the cold-work levels would be in excess of 20 percent, the MRP methodology was crediting either "Primary Category" or "Existing Program" category inspections of the components. The staff finds this basis to be acceptable because either the components had been appropriately screened out for inspection as "No Additional Measures" components for the program or the applicant is performing appropriate inspections of the components to account for the possibility that the stress levels for the components would be in excess of those assumed for the components in the MRP-191 and MRP-227-A reports. The concern raised in RAI B2.1.6-4d, Part a., is resolved.

In its response to RAI B.2.1.6-4d, Part b., the applicant stated that the methodology in TR MRP-227-A assumed that the degradation rate of the reactor internals would decrease during the second 30 years of operation. The applicant stated that this basis assumes the use of low-leakage reactor cores during this period, and thus precludes the use of out-in core loading patterns. The applicant also stated that Attachment 1 in EPRI Letter No. 2013-025 provides criteria for resolving the request in RAI B.2.1.6-4d, Part b. The applicant explained that, for Westinghouse PWRs, the EPRI MRP established upper axial and lower axial fuel loading boundary limitations (as summarized on the previous page) which, if met, may be used to demonstrate that the fuel loading assumptions of the MRP-227-A report are bounding for the RVI components at Callaway.

In regard to meeting the criterion on average core power density for the reactor, the applicant clarified that, historically, the average core power density for Callaway has been 111.7 watts/cm^3 since Cycle 3, when licensed reactor power for the facility was uprated, and was 106.9 watts/cm^3 prior to the power uprate. The applicant stated that the upper axial boundary criteria have always been less than 124 watts/cm^3 and that this demonstrates that this fuel loading pattern criterion meets the limiting assumptions set for it in EPRI MRP Letter 2013-025.

With regard to the heat generation figure of merit, the applicant stated that all reload fuel cycles met the limit of 68 watts/cm^3, with the exception of those for fuel cycles 2 and 13. The applicant stated that duration of fuel cycle 2, which ran from April 1986 to September 1987, amounted to 1.15 effective full power years (EFPY) of power operation, and that duration of fuel cycle 13, which ran from November 2002 to April 2004, amounted to 1.26 EFPY. The applicant stated that, although the heat generation figure of merit exceeded 68 watts/cm^3 during operating cycles 2 and 13, the fuel cycles occurred in the first 20 years of operation. The applicant stated that the heat generation figure of merit did not exceed this value during the next 10 years of operation, and is not expected to exceed it in the second 30 years of operation. The applicant stated that, since these two fuel cycles occurred in the first 20 years of operation, they do not invalidate the requirement to not use out-in loading patterns during the second 30 years of operations. The applicant also stated that the relatively short duration of these two fuel cycles in the first 30 years of operation are offset by many more years of operation in which the heat generation figure of merit was below the limit established by the MRP.

The applicant also stated that, although the distance from the active fuel to the upper core plate has varied as a result of changes in fuel design, this distance has always been greater than 12.2 in., which meets the limit set by this parameter in EPRI MRP Letter 2013-025. The applicant stated that, to ensure that these limits are met in future core designs, it will continue to use in-out core loading patterns for Callaway in all future fuel cycles and that the core design procedure will be modified to include steps calling for the review of the following core loading pattern parameters:

(1) Distance between the top of the active fuel and the upper core plate greater than 12.2 in.

(2) Reactor average core power density less than 124 watts/cm^3

(3) Reactor heat generation figure of merit, F less than or equal to 68 watts/cm^3

The applicant stated that Commitment No. 43 was added to LRA FSAR supplement Table A4-1 in the applicant's letter of January 16, 2014 (ML14017A008 for the Cover Letter and ML14017A007 for the enclosure containing the commitment), in order to ensure that the core design procedure will be revised accordingly.

The staff noted that, in its response to RAI B2.1.6-4d, Part b., the applicant provided the specific value of the maximum average core power density for Callaway over the last 30 years and demonstrated that this power density is less than the MRP Letter's upper bound limit of 124 watts/cm^3 for average core power densities of Westinghouse-designed reactor units. The staff noted that the applicant also provided specific information to demonstrate that, with the exception of operations during cycles 2 and 13, the heat generation rate figure of merit values for the unit did not exceed the 68 watts/cm^3 threshold limit established for Westinghouse-designed plants in EPRI MRP Letter No. 2013-025, and that, for at least the last 10 years, operations at Callaway have resulted in heat generation rates that are within this limit. The staff also noted that the applicant had assessed the nominal distance between the top of the active core and the upper core plate and had provided sufficient information to demonstrate that the minimum 12.2-foot distance would be achieved in spite of any minor variations that may occur in the lengths of the actual fuel design configurations.

In addition, the staff noted that, in the applicant's letter of January 16, 2014 (ML14017A008 for the Cover Letter and ML14017A007 for the enclosure containing LRA Commitment No. 43), the applicant amended the LRA to include Commitment No. 43 in FSAR supplement Table A.4-1, which includes the following actions:

> The core design procedure will be modified to include a review for the following core design parameters to ensure that these limits are met in future core designs:
>
> - Distance between the top of the active fuel and the upper core plate greater than 12.2 in.
> - Reactor average core power density less than 124 watts/cm^3
> - Reactor heat generation figure of merit, F less than or equal to 68 watts/cm^3

The staff verified that, by letter dated February 14, 2014, the applicant responded to indicate that Commitment No. 43 had been completed and that the core design procedure had been revised to include procedural steps to review the active fuel–upper core plate distance, average core power density, and heat generation figure of merit value parameters during future plant

operations, and to compare these parameters against the EPRI MRP's threshold values for these parameters in EPRI MRP Letter 2013-025.

Based on this review, the staff finds that the applicant has provided adequate demonstration that the fuel loading patterns assumed in MRP-227-A are and will be representative of plant operations at Callaway because: (a) for all three parameters (with the exception of the heat generation figure of merit for Cycles 2 and 13), the applicant has demonstrated that the core loading parameters are within the thresholds set for these parameters in EPRI MRP Letter 2013-25; (b) this demonstrates that the core loading patterns for the reactor unit are bounded by the fuel loading assumptions for Westinghouse-designed internals in the MRP-227-A report; and (c) the applicant has amended its core operating procedures to perform reviews of the average core density, heat generation figure of merit, and active fuel–upper core plate distance parameters during the period of extended operation. The staff's concern in RAI B2.1.6-4d, Part b, is resolved.

Therefore, based on this review, the staff finds that the applicant has adequately addressed the actions requested in A/LAI #1 because the applicant has provided sufficient information to demonstrate that either the cold work-induced stress level and fuel loading patterns for the unit are within those established for Westinghouse-designed PWRs in EPRI MRP Letter 2013-025 or has demonstrated that the program accounts for potential deviations from the EPRI MRP's stress level or fuel loading pattern assumptions by inspecting the components in accordance with the EPRI MRP recommendations in TR MRP-227-A. Furthermore, the staff has confirmed that, consistent with the procedural changes that have been made in accordance with completion of LRA Commitment No. 43, the applicant will continue to assess plant performance against the fuel load pattern assumptions and criteria that were established in EPRI MRP Letter 2013-025 in order to demonstrate that future operations of the Callaway reactor will continue to conform with these limits during the period of extended operation. Therefore, the requested action in A/LAI #1 is resolved, and Open Item B2.1.6-1, Part (a) is closed.

Evaluation of the Response Summary to A/LAI #2. In A/LAI #2, the staff requested that PWR applicants for license renewal should perform a review of the CLBs against the information in Tables 4-4 and 4-5 of the MRP-191 report and identify whether these tables contain all of the RVI components that are within the scope of license renewal for their facilities in accordance with 10 CFR 54.4. If the tables do not identify all the RVI components that are within the scope of license renewal for its facility, the staff recommended that the applicant identify the missing component(s) and propose any necessary modifications to the program defined in MRP-227-A when submitting its plant-specific AMP for staff review. The staff stated that the AMP should provide assurance that the effects of aging on the missing component(s) will be managed for the period of extended operation. In its response to A/LAI #2, the applicant stated that "Callaway AMR items for RVI components in LRA Table 3.1.2-1 have been updated to be consistent with MRP-191 and MRP-227-A report bases for Westinghouse reactor internals."

The staff noted that the applicant was already addressing some additional aging management issues in the CLB for the RVI components that would not specifically be addressed through the implementation of the MRP-227-A methodology and the response summary to these A/LAIs did not credit the additional conservatisms being applied due to aging management of its RVI internals. Specifically, the staff noted that in LRA Table 3.1.2-1, the applicant includes AMR items for the RVI components that credit one of the following three condition monitoring AMPs (i.e., inspection-based AMPs) for aging management of the plant's RVI components: (a) PWR Vessel Internals Program, for those RVI components that are defined as Westinghouse-design "Primary Category," "Expansion Category," or ASME Section XI "Existing Program" components

in the MRP-227-A report; (b) Flux Thimble Tube Inspection Program, for the RVI flux thimble tubes; and (c) ASME Section XI Inservice Inspection, Subsections, IWB, IWC, and IWD Program, for those components that are defined as ASME Code Section XI, Examination Category B-N-3 core support structure components for the CLB but are designated as "No Additional Measure" components under the EPRI MRP's methodology in the MRP-227-A report.

The staff noted that, between these three AMPs, the applicant will be applying a sampling basis to the inspection of its RVI components that is more conservative than what the EPRI MRP would have the applicant inspect in accordance with Tables 4-3, 4-6, and 4-9 in the MRP-227-A report. Examples of RVI components that would be omitted from inspection under the MRP-227-A methodology basis but will be inspected by the applicant in accordance with the ASME Code Section XI ISI requirements for Examination Category B-N-3 components include (but are not limited to) the support pins (split pins) in the control rod guide tube (CRGT) assemblies, the reactor vessel Charpy-impact specimen holders, and the neutron shield panel. The applicant's response to RAI 3.1.2.1-1 identifies those RVI components that will be inspected as ASME Section XI, Examination Category B-N-3 requirements for the CLB, but would not be inspected in accordance with the MRP-227-A methodology basis due to their categorization as "No Additional Measures" components.

The staff also noted that, in the LRA, as amended by the applicant's response to RAI 3.1.2.1-2, Parts a. and b., the applicant identified that the incore instrumentation (ICI) support structure upper and lower tie plates were additional plant-specific "Expansion Category" components for the applicant's PWR Vessel Internals Program and that any plans to inspect these components as additional "Expansion Category" components would be tied to the inspection results of those "Primary Category" inspections that will be performed on the CRGT lower flanges during the period of extended operation. The staff noted that this is in addition to those "Expansion Category" inspections that would normally be applied to the BMI column bodies and lower support column bodies under the MRP-227-A methodology when warranted by the inspection results for the CRGT lower flange components. Thus, the staff noted that the applicant had adjusted its LRA to include the ICI support structure upper and lower tie plates as additional "Expansion Category" components for the program and its basis for resolving the request in A/LAI #2.

Further clarifications on the applicant's AMR item bases for the RVI components are given in the applicant's responses to RAIs 3.1.2.1-2, 3.1.2.1-3, 3.1.2.1-4, 3.1.2.1-5, and 3.1.2.2-1. The staff reviews the adequacy of the AMR items for the RVI components in SER Sections 3.1.2.1.2, 3.1.2.1.3, 3.1.2.2.10, and 3.1.2.2.14. The staff's evaluations in these SER sections include the staff's bases for: (a) resolving the staff's requests that were issued in RAI Nos. 3.1.2.1-1, 3.1.2.1-2, 3.1.2.1-3, 3.1.2.1-4, 3.1.2.1-5 and 3.1.2.2-1; and (b) accepting the applicant's AMR items for these components, as given in LRA Table 3.1.2-1 and clarified in the RAI responses and in specific LRA amendments that were provided in the applicant's letters dated April 25, 2012, and October 24, 2012.

In addition, based on the staff's review of the applicant's response A/LAI #7 (refer to the *Evaluation of the Response Summary to A/LAI #7* section that follows), the staff noted that the applicant does not need to make any programmatic adjustments for those RVI components at Callaway that are made from CASS, martensitic stainless steel, or precipitation-hardened martensitic stainless steel materials because: (a) the staff has confirmed that the components that are made from these materials have been dispositioned as "No Additional Measures" components in the MRP-227-A and MRP-191 reports, and (b) this is consistent with the staff's

basis for addressing A/LAI #7 in the staff's revised SE on the MRP-227-A methodology (refer to the SE of December 16, 2011).

Based on this review, the staff finds that the applicant has adequately addressed the action requested in A/LAI #2 because: (a) the applicant has credited additional ASME Code Section XI inspections and Expansion Category inspections of the RVI components in the plant design as part of the applicant's aging management bases for these components; (b) these plant-specific inspection bases were added to address the specific design configurations of the RVI upper and lower internals assemblies at the Callaway facility and are in addition to and go beyond the augmented inspection criteria that were recommended for the Westinghouse-designed RVI components in the MRP-227-A report; and (c) for the remaining RVI components, the applicant has provided sufficient demonstration that the EPRI MRP's protocols for inspecting the components do not need to be altered or augmented beyond those recommended for the components in TR MRP-227-A. The request in A/LAI #2 is resolved.

Evaluation of the Response Summary to A/LAI #3. In A/LAI #3, the staff recommended that applicants applying the MRP-227-A methodology should perform a plant-specific analysis either to justify the acceptability of an applicant's or licensee's existing programs for its CRGT split pins, or else identify changes to the programs that should be implemented to manage the aging of these components for the period of extended operation. The staff requested that the results of this plant-specific analysis and a description of the plant-specific program being relied upon to manage aging of the CRGT split pins should be submitted as part of the applicant's RVI management AMP that is provided in the LRA.

The applicant stated that the evaluation of the adequacy of plant-specific "Existing Programs" for the Callaway RVI components in the AMR items of LRA Table 3.1.2-1 have been updated to address the cracking of the CRGT pins (split pins) as Existing Program Components to be consistent with MRP-227-A.

The staff verified that in the applicant's letter of October 24, 2012 (ML12299A248 for the Cover Letter and ML12299A249 and ML12299A250 for the associated enclosures), the applicant amended its AMR item for the CRGT split pins to credit the ASME Code Section XI "Existing Program" inspections as the basis for managing cracking and loss of material due to wear that may occur in the CRGT split pin components during the period of extended operation. Therefore, the staff finds this basis to be acceptable because the applicant's application of the ASME Code Section XI, Examination Category B-N-3 requirements to the CRGT split pins will ensure that the applicant will inspect the components even though they have already been replaced with split pins that are made from more fracture-resistant materials (i.e., the split pins from the more SCC susceptible Alloy X-750 Inconel materials have already been replaced with CRGT split pins made from cold-worked type 316 austenitic stainless steel). On the basis of this review, the staff concludes that the applicant has addressed the action requested in A/LAI #3 because the applicant will be inspecting the CRGT split pins in accordance with its ASME Section XI ISI Program requirements, as applied by inspection criteria equivalent to those for ASME Code Section XI, Examination Category B-N-3 components. The action requested in A/LAI #3 is resolved.

Evaluation of the Response Summary to A/LAI #4. In A/LAI #4, the staff recommended that B&W applicants or licensees should confirm that the core support structure upper flange weld was stress-relieved during the original fabrication of the RPV in order to confirm that the assumption for these welds in MRP-227-A basis is applicable to the fabrication of the weld in B&W applicant's plant design.

The applicant stated that the A/LAI on B&W core support structure upper flange stress reliefs is not applicable to the design of the RVI components at the Callaway. The staff finds this basis to be acceptable because the nuclear steam supply system for Callaway was designed by Westinghouse Corporation.

The staff confirmed that LRA AMR Table 3.1.2-1 indicates that the analogous core barrel upper flange welds for the Callaway plant are within the scope of the applicant's PWR Vessel Internals Program and that the AMP will be crediting the "Primary Category" inspections for these welds in the MRP-227-A methodology as the basis for aging management of these welds. On the basis of this review, the staff concludes that the applicant has addressed the action requested in A/LAI #4 because the action item is not applicable to the design of the RVI components at Callaway. The action requested in A/LAI #4 is resolved.

Evaluation of the Response Summary to A/LAI #5. In A/LAI #5, the staff recommended that Westinghouse-design applicants for renewal should identify the plant-specific acceptance criteria to be applied to evaluations of the results of physical measurement techniques that will be applied to the RVI hold-down spring for the facility, as recommended in Table 5-3 of the MRP-227-A report. The staff recommended that the applicant include its proposed acceptance criteria and explain how the proposed acceptance criteria are consistent with both the plant's licensing basis and the need for maintaining the intended function of the hold-down spring under all licensing basis conditions of operation.

The applicant stated that the application of physical measure techniques are part of the I&E guidelines in MRP-227-A for specific Westinghouse-designed RVI components. The applicant stated that the physical measurements for the Callaway RVI hold-down spring are identified in program element 6 of GALL Report AMP XI.M16A, "PWR Vessel Internals," and that Callaway will determine the acceptance criterion to be consistent with Table 5-3 of the MRP-227-A report. The applicant's response to A/LAI #5 confirms that the applicable Callaway component that is within the scope of the A/LAI is the Callaway RVI hold-down spring. During the audit, the staff determined that the applicant's PWR Vessel Internals Program appropriately included "detection of aging effects" program element criteria to: (a) perform direct physical measurements of the spring height for the hold-down spring and (b) perform additional measurements of hold-down spring height over the next two RFOs if the original spring height measurement was not sufficient to demonstrate adequate hold-down spring life during the period of extended operation.

The staff finds this approach to be acceptable because it will provide the applicant with a reasonable basis for estimating the amount of hold-down spring height that will occur such that it will meet the criterion for this type of aging management in Table 5-3 of the MRP-227-A report to determine the amount of spring height. However, the staff noted that the applicant is deferring the establishment of the acceptance criteria that will be applied to the evaluation of the physical measurement results for the hold-down spring and that this does not resolve the request in A/LAI #5.

By letter dated December 17, 2012, the staff issued RAI B2.1.6-4a, requesting, in part, that the applicant provide additional information and clarifications on how it would resolve the action item in A/LAI #5. The staff identified this issue as Open Item B2.1.6-1, Part (b).

By letter dated January 24, 2013 (ML13029A243 for the Cover Letter and ML13029A244 for the enclosures containing the RAI response and associated LRA amendments for LRA Amendment No. 20), the applicant provided its response to RAI B2.1.6-4a indicating that it has replaced the hold-down spring with a Type 403 martensitic stainless steel material and that under the

methodology in the MRP-227-A report, hold-down springs made from Type 403 materials do not need to be subject to the EPRI MRP's physical measurement inspections that are recommended for hold-down springs made from Type 304 austenitic stainless steel materials.

The staff noted that, during the development of the EPRI MRP's recommended augmented inspection methodology for Westinghouse-designed RVI components in the MRP-227-A report and the staff's endorsement of that methodology (refer to NRC's revised SE on the MRP-227-A report dated December 16, 2011, as given in ADAMS ML11308A770), the staff endorsed the EPRI MRP's basis that Westinghouse-designed hold-down springs made from Type 403 martensitic stainless steel materials are not subject to stress relaxation such that the functionality of the component will be jeopardized during the period of extended operation under design basis loading conditions. Specifically, the NRC accepted the EPRI MRP's position that loss of preload due to stress relaxation or wear would not need to be managed in hold-down springs made from Type 403 martensitic stainless steel materials due to better material stiffness properties of Type 403 materials, when compared to hold-down springs that are made from Type 304 austenitic stainless steel materials.

Therefore, based on this verification, the staff concluded that the applicant had provided an acceptable basis for concluding that loss of preload due to stress relaxation would not need to be managed in the hold-down spring at Callaway because: (a) the hold-down spring is made from Type 403 martensitic stainless steel material, and (b) the hold-down spring at Callaway is not within the scope of any MRP-defined augmented inspection criteria in the MRP-227-A report. Therefore, based on this review, the staff has confirmed that the applicant's response to RAI B2.1.6-4a has adequately addressed the NRC's recommended action in A/LAI #5. The action requested in A/LAI #5 is resolved and Open Item B2.1.6-1, Part (b) is closed.

Evaluation of the Response Summary to A/LAI #6. In A/LAI #6, the staff recommended that B&W-design applicants for renewal should justify the acceptability of certain B&W RVI components for continued operation through the period of extended operation by performing an evaluation, or by proposing a scheduled replacement of the components.

The applicant stated that the A/LAI regarding the evaluation of inaccessible and noninspectable B&W RVI components is not applicable to the design of the RVI components at Callaway because the components were designed by Westinghouse. The staff finds this basis to be acceptable because the RVI components at Callaway were designed by Westinghouse and not by B&W. On the basis of this review, the staff concludes that the applicant has addressed the actions requested in A/LAI #6 because the action item is not applicable to the design of the RVI components at Callaway. The action requested in A/LAI #6 is resolved.

Evaluation of the Response Summary to A/LAI #7. In A/LAI #7, the staff recommended that license renewal applicants for Westinghouse reactors should develop plant-specific analyses to demonstrate that lower support column bodies made from cast austenitic stainless steel (CASS), martensitic stainless steel, or precipitation-hardened stainless steel materials will remain functional during the period of extended operation. The staff also recommended that these analyses should consider the possibility of loss of fracture toughness occurring in these components as a result of thermal aging and neutron irradiation embrittlement and should consider any limitations on accessibility of the components to inspection and the resolution and sensitivity of the inspection techniques that would be applied to these components. The staff recommended that the plant-specific analysis should be consistent with the plant's licensing basis and the need to maintain the functionality of the components being evaluated under all licensing basis conditions of operation. The staff also recommended that the applicant should include the plant-specific analysis as part of the PWR Vessel Internals Program that would be

submitted in accordance with A/LAI #8, Item (1) or as part of the inspection plan that would be submitted in accordance with A/LAI #8, Item (2).

The applicant stated that this A/LAI is not applicable to Callaway. The applicant stated that the design of the RVI components at Callaway does not include lower support column bodies that are made from CASS materials.

The staff noted that the MRP-227-A report identifies that the following RVI components in Westinghouse-designed PWRs may be fabricated from CASS materials (e.g., CF8 CASS materials): (a) CRGT assembly lower flanges, (b) bottom mounted instrumentation (BMI) column cruciform, (c) lower internals assembly lower support casting, and (d) lower support assembly lower support column bodies.

The staff reviewed FSAR Section 4.5.2, "Reactor Internals Materials," and noted that the FSAR indicates that RVI components at Callaway are typically made from either wrought or forged stainless steel grades (i.e., from Type 304 or 316 austenitic stainless steels) or Alloy X-750 Inconel materials. Therefore, staff noted that the topic and issue raised in A/LAI #7 would not be applicable to the design of the lower core support column bodies because they are not made from CASS materials. However, the staff also noted that the scope of A/LAI #7 also applies to any other component that is made from a CASS, martensitic stainless steel, or precipitation-hardened martensitic stainless steel material and was not considered and evaluated in the development of the MRP-227-A report (i.e., not considered or evaluated in either MRP-227-A or the supporting MRP-191 background document). The staff confirmed that FSAR Table 5.2-4 identifies that the Callaway RVI design includes RVI components made from CF8 or CF8A CASS materials. Thus, it was not evident which of the RVI components in the plant design were made from these types of CASS materials, or for each RVI component made from CASS, why the applicant would not need to provide a supporting flaw tolerance analysis, functionality analysis, or CASS susceptibility analysis for the component, as recommended in A/LAI #7.

By letter dated September 20, 2013, the staff issued RAI B2.1.6-4b, requesting that the applicant consider the information in FSAR Table 5.2-4 and, based on this information, identify those RVI components that are specifically fabricated from CF8 or CF8A CASS materials. For those RVI components that are made from these materials, the staff asked the applicant to clarify whether the components were considered in the development of the MRP-227-A recommendations for management of thermal aging embrittlement and neutron irradiation embrittlement effects and dispositioned in accordance with applicable component category recommendations for the components in the MRP-227-A report. If it is determined that any RVI CASS component was not considered in the development of the MRP-227-A report and appropriately dispositioned in the report, the staff asked the applicant to clarify and justify how the PWR Vessel Internals Program will be adjusted under A/LAI #2 to manage loss of fracture toughness in the components as a result of potential neutron irradiation embrittlement and thermal aging embrittlement mechanisms; consistent with the position in A/LAI #7, if it is determined that the basis for aging management (as applicable) will be by implementation of a component-specific evaluation, the staff requested that the applicant submit the evaluation for NRC review and approval as part of the LRA review. The staff identified this issue as Open Item B2.1.6-1, Part (c).

The applicant responded to RAI B2.1.6-4b in a letter dated January 16, 2014 (ML14017A008 for the Cover Letter and ML14017A007 for the enclosures containing the RAI response and associated LRA amendments for LRA Amendment No. 29). The applicant stated that there are only two RVI components at Callaway that are fabricated from CASS: (a) the BMI column

cruciforms and (b) an offset instrumentation column cruciform that was evaluated in accordance with the criteria in MRP-191 for evaluating BMI column cruciforms. The applicant stated that the MRP-227-A functionality assessment for these CASS components placed the components in the "No Additional Measures" assessment category. The applicant also stated that the remaining RVI components that were identified in MRP-191 as possibly being fabricated from CASS materials (i.e., the CRGT assembly intermediate and lower flanges, upper support column bases in the upper internals assembly, lower support column bodies and lower support in lower internals assembly) were fabricated from non-cast austenitic stainless steel materials. Therefore, the applicant stated that aging management of thermal aging embrittlement and neutron embrittlement effects of CASS RVI components at Callaway is not required.

The staff noted that the applicant's response to RAI B2.1.6-4b clarified that the BMI column cruciform (including the offset instrumentation column cruciform) are the only RVI components at Callaway that are made from CASS materials and that these components were dispositioned as "No Additional Measures" components in accordance with MRP's methodologies in MRP-227-A and MRP-191. The staff verified that the MRP has evaluated these CASS components in MRP-227-A and MRP-191 reports and placed these components in the MRP's "No Additional Measures" category. The staff also noted that, in the NRC's SE of December 16, 2011, the NRC established the following position in regard to the need for performing augmented aging management of CASS components in the "No Additional Measures" category:

> . . . , the requirement [. . for augmented analysis . .] may not apply to [. .CASS . .] components that were previously evaluated as not requiring aging management during development of MRP-227. That is, the requirement would apply to components fabricated from susceptible materials for which an individual licensee has determined aging management is required, for example during their review performed in accordance with Applicant/Licensee Action Item 2.

Therefore, based on this review, the staff finds that the applicant has provided an acceptable basis for concluding that these CASS components do not need to be subjected to augmented inspections or analyses beyond those recommended in the MRP-227-A report because the staff has confirmed that these RVI components at Callaway have been dispostioned in the MRP-227-A report as "No Additional Measures" components and, consistent with the staff's revised SE on MRP-227-A, CASS components falling into the "No Additional Measures" category do not require aging management in accordance with the criteria in A/LAI #7. On the basis of this review, the staff concludes that the applicant has adequately addressed the action requested in A/LAI #7 because the staff has verified that the CASS RVI components, as "No Additional Measures" components, do not need to be within the scope of any augmented inspections or evaluations, as defined in accordance with the methodology in MRP-227-A. The action requested in A/LAI #7 is resolved and Open Item B2.1.6-1, Part (c) is closed.

Evaluation of the Response Summary to A/LAI #8, Items (1) – (5). MRP-227-A, A/LAI #8, is divided into five items. The applicant's responses are evaluated as follows.

- A/LAI #8, Item (1). In A/LAI #8, Item (1), the staff recommended that PWR applicants for renewal submit an AMP in the LRAs that addresses the 10 AMP program elements for aging management of PWR RVI components in GALL Report AMP XI.M16A, "PWR Vessel Internals."

  The applicant stated that Callaway has provided the PWR Vessel Internals Program for NRC audit that addresses the 10 program elements of GALL Report AMP XI.M16A. The

applicant clarified that the basis documents for the PWR Vessel Internals Program have been updated to conform with the recommendations in the MRP-227-A report and the NRC's revised SE on this report dated December 16, 2011 (ML11308A770).

During the audit of the PWR Vessel Internals Program, the staff verified that the basis document for the AMP was based on a direct comparison to the 10 program elements that are defined for these types of AMPs in GALL Report AMP XI.M16A, "PWR Vessel Internals." The staff also noted that the applicant has addressed the action requested in A/LAI #8, Item (1) because the staff has confirmed that: (a) the applicant has included an RVI management AMP in the LRA that is based on the 10 program elements recommended for PWR RVI management AMPs in GALL Report AMP XI.M16A, and (b) the inclusion of this AMP in the LRA conforms to the action that is recommended and requested in A/LAI #8, Item (1). On the basis of its review, the staff concludes that the applicant has conformed to the action recommended in A/LAI #8, Item (1). The staff's audit evaluation of the PWR Vessel Internals Program is given in the audit report for this LRA and supplements the evaluation of the PWR Vessel Internals Program in this SER section. The action requested in A/LAI #8, Item (1) is resolved.

- A/LAI #8, Item (2). In A/LAI #8, Item (2), the staff recommended that, to ensure the MRP-227-A program and the plant-specific action items will be carried out by PWR license renewal applicants, the applicant should submit an inspection plan which addresses the identified plant-specific action items for staff review and approval consistent with the licensing basis for the plant. In this A/LAI, the staff stated that, if an applicant plans to implement an AMP that deviates from the guidance provided in the MRP-227-A report, the applicant should identify where its AMP deviates from the recommendations of MRP-227-A report and should provide a justification for any deviation that impacts the report's recommendations for "Primary" and "Expansion" inspection category components.

  The applicant stated that it will provide the inspection plan consistent with LRA Commitment No. 4 within 24 months after the issuance of MRP-227-A. The applicant stated that the inspection plan will address plant-specific action items and identify any deviations to MRP-227-A with justification. However, as has been stated previously in the introduction to the overall A/LAI evaluation section, the staff did not permit the applicant to use LRA Commitment No. 4 as a basis for resolving any A/LAIs that remained as open items for the program because: (a) Callaway is identified as a Category D facility under the RVI review categorizations in NRC RIS 2011-07; and (b) under this categorization, the applicant would have to resolve any potential issues with the inspection bases for the AMP (including resolution of any applicable A/LAIs) as part of the basis for getting the LRA's PWR Vessel Internals Program approved by the staff.

  The staff noted that the applicant has provided an acceptable basis for resolving all A/LAIs on the MRP-227-A methodology that apply to the design of the Westinghouse-designed RVI components at Callaway and has made applicable adjustments of the program based on the actual design of the RVI components at Callaway. Examples of this are: (a) the applicant's identification in its April 23, 2014, letter that the Callaway baffle-former assembly design does not include baffle-edge bolts, which otherwise would need to be inspected under the MRP's recommended program if they were present in the plant design; (b) the applicant's identification that its Inservice Inspection Program (LRA AMP B2.1.1) will be used to inspect those RVI components that are identified as being "No Additional Measures Components" under the MRP-227-A methodology but will be inspected using criteria equivalent to those for ASME Code Section XI, Examination Category B-N-3 removable core support structure components in the CLB; and (c) the applicant's identification of the incore instrumentation (ICI) support structure upper and

lower tie plates as additional plant-specific "Expansion Category" components for the applicant's Program and plans to inspect these components as additional "Expansion Category" components based on the inspection results of those "Primary Category" inspections that will be performed on the control rod guide tube (CRGT) lower flanges in the plant design.

Therefore, based on this review, the staff concludes that the applicant will not need to submit an inspection plan for staff approval in accordance with an LRA commitment in the FSAR supplement and that, instead, the staff's reviews of the AMR items for the Callaway RVI components, as given in applicable subsections of SER Sections 3.1.2.1 and 3.1.2.2, and the applicant's PWR Vessel Internals Program and responses to applicable A/LAIs on the MRP-227-A methodology, as given in this evaluation section, serve as an acceptable basis for either confirming consistency of the AMP with the recommendations of the MRP-227-A methodology (as applied to the Callaway design), or else that the applicant has adjusted the program accordingly based on the actual design of the RVI components in the site and the recommended actions in A/LAI No. 2. The action requested in A/LAI #8, Item (2) is resolved.

- A/LAI #8, Item (3). In A/LAI #8, Item (3), the staff stated that 10 CFR 54.21(d) requires that an FSAR supplement for the facility contain a summary description of the programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses (TLAAs) for the period of extended operation.

  In this A/LAI, the staff stated that license renewal applicants referencing the MRP-227-A report for their RVI management AMP shall ensure that the programs and activities specified as necessary in the MRP-227-A report are summarily described in the FSAR supplement.

  The applicant stated that the Callaway FSAR supplement described in LRA Section A1.6 includes an FSAR supplement summary description for the applicant's PWR Vessel Internals Program and that it is consistent with the MRP-227-A report and with the NRC's revised SE on the MRP-227-A report's methodology (ML11308A770). The applicant clarified that the FSAR supplement summary description for the RVI metal fatigue TLAAs does not credit the PWR Vessel Internals Program as the basis for accepting the TLAAs in accordance with the TLAA acceptance criterion in 10 CFR 54.21(c)(1)(iii).

  The staff confirmed that the applicant has included the FSAR supplement summary description for the PWR Vessel Internals Program in LRA Section A1.6 and the FSAR supplement summary description for the RVI metal fatigue TLAAs in LRA Section A3.2.2, "ASME Section III Subsection NG Fatigue Analysis of Reactor Pressure Vessel Internals." The staff finds that the applicant has addressed the request in A/LAI #8, Item (3) because: (a) the staff confirmed that the applicant has included the applicable FSAR supplement summary descriptions for the applicant's PWR Vessel Internals Program in Appendix A of the LRA and (b) this demonstrates compliance with the requirement in 10 CFR 54.21(c)(2). The action requested in A/LAI No. 8, Item (3) is resolved.

- A/LAI #8, Item (4). In A/LAI #8, Item (4), the staff stated that 10 CFR 54.22 requires each license renewal applicant to submit any technical specification (TS) changes (and the justification for the changes) that are necessary to manage the effects of aging during the period of extended operation as part of its LRA. In this A/LAI, the staff recommended that, for those plant CLBs that include mandated inspection or analysis requirements for the RVI components either in the operating license for the facility or in the facility TS, the applicant perform a comparison of the mandated requirements with the recommendations in the MRP-227-A report. The staff stated that, if the mandated requirements differ from

the recommended criteria in MRP-227-A report, the conditions in the applicable license conditions or TS requirements take precedence over the MRP recommendations and must be complied with.

In response to this A/LAI, the applicant stated the CLB does not include any TS requirements that would need to be changed as a result of the implementation of the augmented I&E recommendations in the MRP-227-A report.

The staff reviewed Callaway Operating License No. NPF-30 and TS for operating license conditions or TS requirements that relate to aging management bases for the RVI components in the plant design. The staff did not note any specific operating license or TS requirements related to design or integrity of the Callaway RVI components. The staff also did not find any operating license or TS requirements for the Callaway that would need to be amended as a result of the applicant's plans to implement the augmented inspection criteria in the MRP-227-A report or the ISIs that are mandated by 10 CFR 50.55a and the ASME Code Section XI for those RVI components that are defined in the Callaway CLB as ASME Code Section XI, Examination Category B-N-3 core support structure components or B-N-2 components such as the clevis insert bolts.

Based on this review, the staff finds that the applicant has addressed the request in A/LAI #8, Item (4) because the staff has confirmed that: (a) the CLB does not include any operating license conditions or TS requirements that relate to the design or structural integrity of the applicant's RVI components and (b) the CLB does not include any operating license conditions or TS requirements that would need to be amended as a result of the applicant's plans to implement the augmented inspection criteria in the MRP-227-A report. The action requested in A/LAI #8, Item (4) is resolved.

- A/LAI #8, Item (5). In A/LAI #8, Item (5), the staff stated that license renewal applicants are required by 10 CFR 54.21(c)(1) to identify all analyses in the CLB for their RVI components that conform to the definition of a TLAA in 10 CFR 54.3. The staff stated that the MRP-227-A report does not specifically address the resolution of TLAAs that may apply to a PWR license renewal applicant's RVI components. Thus, in A/LAI #8, Item (5), the staff recommended that PWR license renewal applicants that reference and will be implementing the recommendations in the MRP-227-A report should evaluate the CLB for their facilities to determine if they have any plant-specific TLAAs for the RVI components that need be addressed. If so, the staff recommended that the applicants submit the applicable TLAAs for NRC review along with the AMPs that will be used to implement the MRP-227-A report recommended activities for RVI components at their facilities.

  In A/LAI #8, Item (5), the staff also stated that, for those CUF analyses on RVI components that are TLAAs, the applicant may use the PWR Vessel Internals Program as the basis for accepting these TLAAs in accordance with 10 CFR 54.21(c)(1)(iii) only if the RVI components within the scope of the CUF analyses are periodically inspected for fatigue-induced cracking in the components during the period of extended operation. The staff stated that the periodicity of the inspections of these components requires adequate justification to resolve the TLAA. Otherwise, staff recommended that the acceptance of these TLAAs shall be done in accordance with either 10 CFR 54.21(c)(1)(i) or (ii), or in accordance with 10 CFR 54.21(c)(1)(iii) using the applicant's program that corresponds to GALL Report AMP X.M1, "Fatigue Monitoring." The staff also stated that, to satisfy the evaluation requirements of ASME Code, Section III, Subsection NG-2160 and NG-3121, the existing fatigue CUF analyses shall include the effects of the RCS water environment.

  The applicant stated that the only TLAAs for the Callaway RVI components are the metal fatigue TLAAs for the Callaway core support structure components. The applicant stated

that these TLAAs are addressed in LRA Section 4.3.3 and are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii). The applicant stated that it does not credit the PWR Vessel Internals Program as the basis for accepting the metal fatigue TLAAs in accordance with 10 CFR 54.21(c)(1)(iii). The staff confirmed that LRA Section 4.3.3 does address the metal fatigue TLAA that is applicable to those RVI components at Callaway that are defined as ASME Code Section III core support structure components. The staff also confirmed that the applicant identifies that these TLAAs are acceptable in accordance with 10 CFR 54.21(c)(1)(iii) and that the applicant will use the Fatigue Monitoring Program to manage the impacts of metal fatigue (cumulative fatigue damage) on the intended function of the RVI core support structure components during the period of extended operation. The staff evaluated the metal fatigue analyses for these components in SER Section 4.3.3. However, the staff also noted that the applicant's response to A/LAI #8, Item (5) did not address how exposure to the RCS environment would be evaluated for impact on: (a) the CUF analyses for these components and (b) the applicant's basis for accepting these TLAAs in accordance with the TLAA acceptance requirement in 10 CFR 54.21(c)(1)(iii).

By letter dated December 17, 2012, the staff issued RAI B2.1.6-4a, requesting, in part, that the applicant provide additional information and clarifications on how it would resolve the action item in A/LAI #8, Item (5). The staff identified this issue as Open Item B.2.1.6-1, Part (d).

By letter dated January 24, 2013 (ML13029A243 for the Cover Letter and ML13029A244 for the enclosures containing the RAI response and associated LRA amendments for LRA Amendment No. 20), the applicant provided its response to RAI B2.1.6-4a proposing to address A/LAI #8, Item (5) in a future submittal of an inspection plan that would be submitted in accordance with LRA Commitment No. 4, as given in FSAR supplement Table A4-1.

The staff noted that, in the applicant's letter of April 26, 2013, the applicant amended the LRA to resolve the request in A/LAI #8, Item (5) by superseding the existing Commitment No. 4 with the following amended commitment:

> Applicant/Licensee Action Item (A/LAI) #8 Item #5. Enhance the Fatigue Monitoring program to evaluate the effects of the reactor coolant system water environment on the reactor vessel internal components with existing fatigue CUF analyses to satisfy the evaluation requirements of ASME Code, Section III, Subsection NG-2160 and NG-3121.

Upon further review, the staff determined that the neither the FSAR supplement for the Fatigue Monitoring Program, as given in LRA FSAR supplement Section A2.1, "Fatigue Monitoring," nor Commitment No. 31 on the Fatigue Monitoring Program in FSAR Table A4-1 had been amended to include the stated enhancement. Therefore, the staff noted that it would need additional justifications on why FSAR supplement Section A2.1 and Commitment No. 31 in FSAR supplement Table A4-1 had not been enhanced consistent with the commitment change in FSAR supplement Table A4-1, Commitment No. 4. The staff also noted that it would need additional clarification on how the program elements of the Fatigue Monitoring Program would be adjusted to evaluate (account for) the effects of the reactor coolant environment on the acceptability of the CUF analyses for the applicable RVI components.

By letter dated September 20, 2013, the staff issued RAI B2.1.6-4c, requesting that the applicant provide its basis why Commitment No. 31 in FSAR Table A4-1 and FSAR Section A2.1, "Fatigue Monitoring," had also not been amended to include this

enhancement. The staff also asked the applicant to clarify and justify how the program elements of the Fatigue Monitoring Program will be adjusted to evaluate the effects of the reactor environment on the CUF analyses for the applicable RVI components.

The applicant responded to RAI B2.1.6-4c in a letter dated October 17, 2013. In its response, the applicant stated that LRA Table A4-1 Commitment No. 4 was revised to delete the A/LAI #8 Item #5 commitment on effects of the reactor water environment on the reactor vessel internals locations with fatigue usage calculations and that, instead, the commitment provisions have been incorporated into LRA Table A4-1 Commitment No. 31. The applicant also stated that the implementation of the commitment is described in LRA Appendix A2.1, LRA Section A3.2.3, and LRA Section B3.1. The applicant stated that it will recalculate each of the reactor vessel internals CUFs identified in LRA Table 4.3-5, Reactor Internals Design Basis Fatigue Analysis Results, to consider the reactor water environmental effect factors (F_{en} factors) using the methods of analysis in NUREG/CR-5704 or NUREG/CR-6909, and that consistent with the corrective actions specified in its Fatigue Monitoring program (LRA Section B3.1), corrective actions include fatigue reanalysis, repair, or replacement of the affected components prior to the adjusted usage factor "U_{en}" reaching a value of 1.0. The applicant stated that LRA AMP B3.1, "Fatigue Monitoring Program," Commitment Nos. 4 and 31 in FSAR supplement Table A4-1, and FSAR supplement Sections A2.1 and A3.2.3 have been amended as shown in Enclosure 2 of LRA Amendment 27 to consider the effects of the reactor water environment on the reactor vessel internals locations with fatigue usage calculations.

The staff reviewed the applicant's response to RAI B2.1.6-4c, as given in its letter of October 17, 2013, and determined that in its amendment of Commitment No. 31, the applicant had committed to performing environmental adjustments of the CUF analyses for the applicable RVI components that had been evaluated in accordance with a fatigue analysis and to using the Fatigue Monitoring Program as the basis for managing environmentally assisted fatigue in those components. The staff noted that the amended basis in this letter was consistent with the staff's position in A/LAI #8, Item (5) because the applicant has committed to assessing the CUF of these components for environmental F_{en} adjustments and using the Fatigue Monitoring Program as the basis for monitoring against those assessments, which is consistent with the staff's program element bases in GALL Report AMP X.M1, "Fatigue Monitoring Program." The staff also confirmed that the applicant has made the appropriate changes to LRA Commitment Nos. 4 and 31, LRA AMP B3.1, and FSAR supplement Sections A2.1 and A3.2.3, to ensure that the Fatigue Monitoring Program will be the basis for ensuring the CUF calculations for the RVI components will be evaluated for environmental effects. On this basis, the staff concludes that the applicant has addressed the action requested in A/LAI #8, Item (5), because the applicant has sufficiently clarified how the Fatigue Monitoring Program will be used to manage environmentally assisted fatigue in these RVI components and has demonstrated that its use of the Fatigue Monitoring Program will be consistent with the staff's recommendations for managing environmentally assisted fatigue in GALL Report AMP X.M1. A/LAI #8, Item (5) and RAI B2.1.6-4c are resolved, and Open Item B2.1.6-1, Part (d) is closed.

On the basis of this review, the staff finds that the applicant has resolved the staff's RAIs related to the applicable A/LAIs on the MRP-227-A methodology, including those in RAI Nos. B2.1.6-4, B2.1.6-4a, B2.1.6-4b, B2.1.6-4c, and B2.1.6-4d. Open Item B2.1.6-1, Parts (a) through (d) are closed.

Operating Experience. LRA Section B2.1.6 summarizes operating experience related to the PWR Vessel Internals Program. The applicant stated that it replaced the Alloy X-750 CRGT support pins with strain hardened 316 stainless steel pins during RFO 13 (spring 2004) to reduce the susceptibility for SCC in the support pins. The applicant stated that this replacement was based on industry operating experience. The applicant noted that no cracked Alloy X-750 support pins were discovered during the replacement process. However, the staff noted that, in LRA Table 3.1.2-1, the applicant identified that it would manage cracking of its stainless steel CRGT support pins using its ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD Program. The staff noted that this basis would be acceptable because it would address the inspection basis that the staff recommended in A/LAI #5 on the MRP-227-A methodology.

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, other than possibly the applicant's bases for resolving the generic operating experience with clevis insert bolt cracking, which had occurred in another U.S. Westinghouse-designed reactor in 2010. The following paragraphs address the applicant's basis for evaluating the applicability of the generic clevis insert bolt operating experience on the applicant's bases for inspecting the components in accordance with the applicable ASME Section XI ISI requirements for Examination Category B-N-2 components.

By letter dated February 12, 2014, the staff issued RAI No. 3.1.2.1-6, Parts (a) and (b), to the applicant to address the clevis insert bolt operating experience on the program element criteria for the PWR Vessel Internals AMP. In RAI 3.1.2.1-6, Part (a), the staff asked the applicant to describe the configuration of clevis insert assembly design at Callaway, including the number of bolts used in the assemblies. The staff also asked the applicant to specify the material of fabrication, including any applicable heat treatments, that were used for the design of the clevis insert bolts at Callaway. In RAI 3.1.2.1-6, Part (b), the staff asked the applicant to discuss and justify whether the operating experience associated with cracking of the clevis insert bolts is applicable to clevis insert assembly designs at Callaway.

The applicant responded to RAI 3.1.2.1-6, Parts (a) and (b), in a letter dated April 3, 2014 (as given in ML14093A781 for the Cover Letter, Non-Proprietary ML14093A780 for Westinghouse's associated nonproprietary response bases to the RAI). The applicant indicated that part of the response was prepared for Callaway by Westinghouse, and included some proprietary information that Westinghouse had identified as trade secrets and would need to be protected in accordance with the requirements in 10 CFR 2.390 from disclosure to members of the general public. The applicant therefore submitted both proprietary and nonproprietary versions of the responses to RAI 3.1.2.1-6, Parts (a) and (b), in which only a very limited amount of information in the proprietary version of the response had been marked for protection from public disclosure.

In the nonproprietary response, Westinghouse clarified that there are some similiarities between the material used in the design of the clevis insert bolts at Callaway and those at the plant with the operating experience. Westinghouse stated that although there is some potential for cracking to occur in clevis insert bolts of both facilities, if cracking did lead to a failure of a clevis insert bolt, the bolt would be held in place by the locking bar in the design. Westinghouse also stated that, if a clevis insert bolt head was to separate from its shaft, the locking bar could, over

time, wear and separate, causing the clevis insert bolt head to become loose in the counterbore recess. However, Westinghouse explained that the as-built radial gaps measured between the core barrel radial keys and the inserts are all less than the height of the clevis insert bolt heads, and therefore, the clevis insert bolt heads would remain captured, unless over a long period of time, potential wear of the bolt heads were to reduce the height of the heads by this amount. Westinghouse explained, however, that the bolt head wear is expected to be small because the bolt material is much harder than material used to fabricate the clevis insert assembly inserts and radial keys. Westinghouse therefore concluded that any effects of potential loose parts would be captured or would have a minimal impact on the lower internals design.

In its response to RAI 3.1.2.1-6, Parts (a) and (b), the applicant also stated that it performs VT-3 inspections on 100 percent of the accessible clevis insert assembly components in accordance with ASME Code Section XI, Examination Category B-N-2 requirements, with the most recent inspection performed during Refueling Outage No. 19 in spring 2013. The applicant stated that the examinations inspected 100 percent of the clevis insert bolt heads and locking bars and that the inspections did not identify any evidence of degradation or damage in the clevis insert bolts or locking bars. The applicant stated that, based on these considerations and results of the inspections during Refueling Outage No. 19, the PWR Vessel Internals Program protocols for applying the ASME Code ISI inspections of the clevis insert assemblies and their bolts do not have to be augmented for the purpose of managing cracking or loss of material due to wear in the clevis insert bolts for the facility.

The staff noted that the information in Westinghouse's nonproprietary response to RAI 3.1.2.1--6, Parts (a) and (b), when coupled with the applicant's response to the RAI, was sufficient to make a determination on whether the ISI interval for performing ASME Code Section XI visual examinations of the clevis insert bolts would need to be augmented to a frequency more frequent than the 10-year ISI interval required by the Code. The staff also noted that, based on Westinghouse's assessment, the cracking in the clevis insert bolts at the reference plant was detected using the 10-year ASME Code Section XI visual VT-3 methods before the clevis insert bolts could fail and induce a loss of the intended structural integrity function of the clevis insert assemblies or other RVI components in the lower internal assembly at the plant, even with the small amount of wear that was detected in the locking bars in the clevis insert bolt design. The staff also noted the operating experience and apparent cause assessment for the reference plant with the clevis insert bolt experience demonstrated that the frequency of performing the ASME Code Section XI visual examinations will be capable of detecting crack-induced clevis insert bolt failures prior to any loss of function in a clevis insert assembly or the generation of a postulated loose part with the potential to impact the intended function of other RVI components in the lower internals assembly.

Therefore, based on the Westinghouse assessment provided in the response to RAI 3.1.2.1-6, and the lack of any cracking or wear detected in the clevis insert assemblies at Callaway to date, the staff noted that the 10-year ASME Code Section XI visual VT-3 inspections performed on the clevis insert assemblies and their bolts will be capable of detecting any cracking or loss of material due to wear in the clevis insert bolts prior to generation of a loose part that could potentially impact the intended functions of the clevis insert assemblies or other internals in the RVI lower internals assembly. Based on this review, the staff finds that the applicant has addressed the impact of the generic operating experience on the ability of the ASME visual examination methods to detect and manage potential cracking and loss of material due to wear in the clevis insert assemblies and clevis insert bolts at Callaway because the applicant has provided a sufficient basis for concluding that the existing ASME inspections will be capable of detecting the postulated age-related effects prior to any postulated loss of the intended

structural integrity function of the clevis insert assemblies or other components in the lower internals assembly. RAI 3.1.2.1-6, Parts (a) and (b), 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. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.M16A was evaluated.

FSAR Supplement. LRA Section A1.6, as amended by letter dated April 25, 2012, provides the FSAR supplement for the PWR Vessel Internals Program. The staff reviewed this FSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff confirmed that the applicant's FSAR supplement summary description provided an acceptable summary of the program with regard to: (a) referencing the MRP-227-A report as being within the scope of the applicant's PWR Vessel Internals Program, (b) identifying the aging effects that will be managed in accordance with the applicant's plans to implement the program, (c) identifying that the PWR Vessel Internals Program is a new AMP that will be implemented within 24 months of EPRI's issuance of the MRP-227-A reports (i.e., by January 9, 2014), and (d) identifying that the applicant's review of relevant generic industry and plant-specific operating experience will be factored into the development and implementation of the program.

The staff also noted that the applicant committed (Commitment No. 4) to implement the new PWR Vessel Internals Program as described in LRA Section B2.1.6 within 24 months after the issuance of MRP-227-A. The staff noted that Commitment No. 4 was captured in Table A4-1 of the applicant's FSAR supplement. However, the staff also noted that, in the applicant's response to RAI B2.1.6-4, dated October 24, 2012, the applicant made the following statement with respect to its plans to provide the NRC staff with the applicant's responses to the A/LAIs on the MRP-227-A methodology:

> Callaway will provide specific responses to the Applicant/Licensee Action Items (A/LAIs) identified in the December 16, 2011, NRC Safety Evaluation on the MRP-227-A methodology in LRA Appendix C. The LRA Appendix C supplement for the NRC Safety Evaluation A/LAIs will be provided consistent with the LRA Table A4-1 item #4 commitment to implement the PWR Vessel Internals [P]rogram as described in LRA Section B2.1.6 within 24 months after the issuance of MRP-227-A. LRA Table A4-1 item #4 also includes the Callaway [RVIs] inspection plan noted in part (b) of A/LAI item 8 of the NRC Safety Evaluation on the MRP-227-A methodology. The Callaway [RVIs] inspection plan will be provided within 24 months after the issuance of MRP-227-A.

By letter dated December 17, 2012, the staff issued RAI B2.1.6-4a, requesting that the applicant provide the basis for not modifying Commitment No. 4 in a manner that is consistent with the bases for this commitment as provided in its response to RAI B2.1.6-4 and that would address the activities or aspects of the applicant's PWR Vessel Internals Program related to its responses to A/LAI Nos. 1, 5, 7, and 8 Item (5). This is identified as Open Item B2.1.6-1, Part (e).

As has been discussed in the "Review of License Renewal Applicant Action Items" section of this evaluation, the staff noted that the applicant resolved the requests in A/LAI Nos. 1, 5, 7, and 8, Item (5) in the following Ameren correspondence letters to the staff:

- Resolved the issues in A/LAI #1 and demonstrated that the methodology in TR MRP--227-A is applicable to the design of the RVI components at Callaway in

Ameren Missouri Letter No. ULNRC-05950, dated January 24, 2013, as supplemented with information provided in Ameren Missouri Letter Nos. ULNRC-06072, dated January 16, 2014; ULNRC-06079, dated February 5, 2014; ULNRC-06080, dated February 14, 2014; ULNRC-06090, dated March 13, 2014; ULNRC-06106, dated March 28, 2014; and ULNRC-06117, dated April 23, 2013.

- Resolved the issue in A/LAI #5 and demonstrated that augmented aging management is not needed for the design of the Callaway hold-down spring in Ameren Missouri Letter No. ULNRC-05950, dated January 24, 2013.
- Resolved the issue in A/LAI #7 and demonstrated that supplemental evaluations would not need to be performed for those components that are made from CASS, martensitic stainless steel or precipitation-hardened stainless steels in Ameren Missouri Letter No. ULNRC-06072, dated January 16, 2014.
- Resolved the issue in A/LAI #8, Subitem 5, and demonstrated that the RVI components with fatigue analyses would be adequately managed by the Fatigue Monitoring Program, including bases for managing the impacts of environmental effects on the fatigue analyses, in Ameren Missouri Letter No. ULNRC-05950, dated January 24, 2013, as supplemented by the response in Ameren Letter No. ULNRC-06050, dated October 17, 2013.

The staff noted that in the applicant's letter of December 20, 2013, the applicant had implemented and closed Commitment No. 4. Based on this review, the staff finds that the applicant has provided an acceptable basis for resolving those A/LAIs that were issued regarding the applicant's basis for implementing the augmented inspection and evaluation activities recommended in the MRP-227-A, such that the applicant would not need to submit an RVI inspection plan to the staff for approval in accordance with the request in A/LAI No. 8, Item (2) or LRA Commitment No. 4.

The staff also noted that the FSAR supplement Table A4-1 included the following additional LRA Commitments for implementing the PWR Vessel Internals Program that were included in the LRA subsequent to the resolution and closure of LRA Commitment No. 4 in the applicant's letter of December 20, 2013 (Ameren Missouri Letter No. ULNRC-06057):

- LRA Commitment No. 43, as proposed in the applicant's letter of January 16, 2014, in which the applicant committed to updating the procedures for the program to incorporate the MRP's new criteria for demonstrating that future operations of the plant will be within the bounds of the assumptions used for the methodology in the MRP-227-A report.
- LRA Commitment No. 44, as proposed in the applicant's letter of February 5, 2014, in which the applicant had committed to the implementation of specific actions or activities in order to resolve the staff's requests in A/LAI #1.

The staff noted that the applicant had implemented and closed Commitment No. 43 in the applicant's letter of January 16, 2014, and implemented and closed Commitment No. 44 in the applicant's letter of April 23, 2014.

Based on this review, the staff finds that the information in the FSAR supplement, as amended by letters dated January 24, 2013, October 17, 2013, December 20, 2013, January 16, 2014, February 5, 2014, February 14, 2014, March 13, 2014, March 28, 2014, and April 23, 2013, is an adequate summary description of the program. The requests in RAI B2.1.6-4a are resolved and Open Item B2.1.6-1, Part (e) is closed.

Conclusion. On the basis of its audit and review of the applicant's PWR Vessel Internals Program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent with those recommended in GALL Report AMP XI.M16A. The staff also concludes that the applicant has appropriately augmented the program based on the applicant's bases for resolving those A/LAIs that were issued in the augmented inspection and evaluation methodology in MRP-227-A and plant-specific considerations that have been evaluated in this SER section and resulted in an adjustment of the MRP's recommended program in accordance with the actions requested in A/LAI #2.

Based on these considerations, the staff also 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 FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.6 Flow-Accelerated Corrosion

Summary of Technical Information in the Application. LRA Section B2.1.7 describes the existing Flow-Accelerated Corrosion Program as consistent with GALL Report AMP XI.M17, "Flow-Accelerated Corrosion." The program manages wall thinning of carbon or low alloy steel piping components in single-phase and two-phase, high energy fluids. The LRA states that the program implements the guidance of EPRI NSAC-202L, Revision 3, "Recommendations for an Effective Flow-Accelerated Corrosion Program." The LRA also states that the program predicts critical locations using a computer code (CHECWORKS™), identifies wall thinning with baseline inspections, and performs followup inspections using ultrasonic, visual or other approved testing techniques. The LRA further states that in conjunction with CHECWORKS™, the program also uses a computer code (FAC Manager Web Edition) to calculate component wear rates for scheduling future inspections, or for determining the need to take corrective actions, such as repair, replacement, or reevaluation.

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.

For the "scope of program," "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 "scope of program" program element in GALL Report AMP XI.M17 recommends that the program includes procedures and administrative controls to maintain the structural integrity of all carbon steel lines containing high-energy fluids. During its audit, the staff noted that Callaway Report No. 4501-01, "Callaway Nuclear Plant FAC System Susceptibility Evaluation," excluded the chemical and volume control (CVC) system from the scope of the Flow-Accelerated Corrosion Program because the system components are constructed from non-susceptible materials. However, LRA Table 3.3.2-10, "Auxiliary Systems - Summary of Aging Management Evaluation - Chemical and Volume Control System," includes carbon steel piping that is being managed for wall thinning by the Flow-Accelerated Corrosion Program. Based on this, it was not clear to the staff whether the CVC system has susceptible material that was not evaluated in Callaway's FAC system susceptibility evaluation report or whether other systems have been excluded, which also contain components made from susceptible materials. By letter dated

July 18, 2012, the staff issued RAI B2.1.7-1, requesting that the applicant clarify this apparent discrepancy.

In its response dated August 21, 2012, the applicant stated that LRA Table 3.3.2-10 incorrectly included carbon steel piping in the CVC system as being managed by the Flow-Accelerated Corrosion Program and that the site's FAC system susceptibility evaluation included these carbon steel components within the auxiliary steam system. The applicant also stated that during its review to determine if there were other similar errors in the LRA, it identified one additional occurrence and consequently revised the appropriate tables in LRA Amendment 7 to remove the two erroneous items. The applicant further stated that these lines were excluded from the FAC program because they operate less than two percent of the time, not because their material is not susceptible to FAC. The staff finds the applicant's response acceptable because the applicant amended the LRA to remove the incorrect information and explained that the system susceptibility evaluation report included the subject carbon steel components within the auxiliary steam system. The staff noted that LRA Table 2.2-1, "Callaway Plant Scoping Results," includes the auxiliary steam system with the main steam supply system and that LRA Section 3.4.2.1.2, "Main Steam Supply System," credits the Flow-Accelerated Corrosion Program for managing wall thinning in carbon steel piping. The staff's concern described in RAI RAI B2.1.7-1 is resolved.

The "scope of program" program element in GALL Report AMP XI.M17 states that the program is described by EPRI guideline NSAC-202L. EPRI NSAC-202L states that the program addresses wall thinning caused by flow-accelerated corrosion (FAC) and that it does not address other thinning mechanisms, such as cavitation and erosive wear. During its review of program's operating experience report, the staff identified several Callaway Action Requests (CARs) indicating that the program addresses wall thinning due to erosion mechanisms. Based on this, the staff had questions regarding the scope of the program. By letter dated July 18, 2012, the staff issued RAI B2.1.7-4 requesting the applicant to clarify whether the program addressed mechanisms other than FAC or whether components that experienced wall thinning because of erosion mechanisms are being managed by another program. In its response dated August 21, 2012, the applicant stated that its Flow-Accelerated Corrosion Program does not manage aging mechanisms other than FAC and that none of the CARs cited in the RAI identified wall thinning due to mechanisms other than FAC in components within the scope of license renewal. In addition, the applicant discussed CAR 200703776, which addressed erosion/corrosion in an essential service water pipe, and stated that this component is monitored for erosion mechanisms by the Open-Cycle Cooling Water System Program.

In its review of the applicant's response, the staff noted that all of the CARs cited in the RAI were initially cited by the applicant in its operating experience review for this AMP. In addition, since the operating experience review report comprises one of the records documenting compliance with 10 CFR Part 54, the portions stating that the Flow-Accelerated Corrosion Program manages loss of material due to erosion in a raw water system appears to be incorrect. In a separate but related effort, the staff noted that in its response to IE Bulletin 87-01, "Thinning of Pipe Walls in Nuclear Power Plants," the applicant stated that its erosion and corrosion program, which was the predecessor of the Flow-Accelerated Corrosion Program, included inspections of stainless steel pipe for erosion due to cavitation. To address these concerns, by letter dated October 12, 2012, the staff issued RAI B2.1.7-4a, requesting the applicant to address the apparent incorrect information in the operating experience review documentation and to discuss the CLB associated with the erosion/corrosion program and how it correlates to the Flow-Accelerated Corrosion Program.

In its response dated November 8, 2012, the applicant stated that CAR 200608992 and CAR 201004190 incorrectly assigned the Flow-Accelerated Corrosion Program as the AMP relevant to the condition prompting the action requests and that it had revised the operating experience review documentation for these two CARs to correct this error. In addition, the applicant explained that although its original response to IE Bulletin 87-01 included raw water components subject to wall thinning due to mechanisms other than FAC, it moved all of these inspections to the new program in response to NRC Generic Letter (GL) 89-13, "Service Water System Problems Affecting Safety-Related Equipment." The applicant stated that it moved the inspections for wall thinning in raw water systems to the GL 89-13 program because the operating conditions such as temperature and oxygen levels of raw water systems are not consistent with those causing FAC. The staff finds the response acceptable because the applicant corrected its operating experience documentation to indicate that the Flow-Accelerated Corrosion Program does not manage aging mechanisms other than FAC. In addition, the applicant clarified that the inspections for wall thinning in raw water systems that it initially included in response to IE Bulletin 87-01 are now part of its GL 89-13 program, which it implements through the Open-Cycle Cooling Water System Program. The staff's concerns described in RAIs B2.1.7-4 and B2.1.7-4a are resolved.

The "detection of aging effects" program element in GALL Report AMP XI.M17 states that the program uses ultrasonic or radiographic testing to detect wall thinning. The LRA states that the Flow-Accelerated Corrosion Program uses ultrasonic, visual or other approved techniques during baseline and followup inspections. During its review, the staff could not find documentation describing how the applicant uses visual inspections to detect wall thinning or whether visual inspections are used in lieu of volumetric techniques to detect wall thinning. By letter dated July 18, 2012, the staff issued RAI B2.1.7-2 requesting the applicant to clarify how visual inspections will be used to detect wall thinning and whether visual inspections will be used in lieu of volumetric examinations.

In its response dated August 21, 2012, the applicant stated that visual examinations may be used for very large diameter piping and for components such as valves that are not suitable for ultrasonic examination because of their shape and thickness. The applicant also stated that visual examinations provide qualitative indications of FAC and are not used to determine wall thickness. The staff notes that NSAC-202L discusses the use of visual observations with followup ultrasonic examinations of areas where damage is observed or suspected. The staff finds the applicant's response acceptable because the applicant clarified how visual examinations are used and that visual examinations do not take the place of volumetric examinations for determining wall thickness. The staff's concern described in RAI B2.1.7-2 is resolved.

The "acceptance criteria" program element in GALL Report AMP XI.M17 states that inspection results are input for a predictive code to calculate the remaining number of operating cycles before a component reaches its minimum allowable wall thickness. Industry guidance, EPRI NSAC 202L, Revision 2, "Recommendations for an Effective Flow-Accelerated Corrosion Program," states that a minimum safety factor should never be less than 1.1 to account for wear rate inaccuracies when calculating the remaining service life of a component. Although the program's implementing procedure, EDP-ZZ-01115, "Flow-Accelerated Corrosion of Piping and Components Predictive Performance Manual," specifies a safety factor of 1.1 in calculating an "inspection index," LRA Section B2.1.7 states that FAC Manager Web Edition is utilized to calculate wear, wear rates and the next scheduled inspection. During its review of onsite documentation related to FAC Manager Web Edition, the staff could not verify that the applicant's program used a minimum safety factor of 1.1 in calculating the next scheduled

inspection. By letter dated July 18, 2012, the staff issued RAI B2.1.7-3 requesting the applicant to confirm that calculations use a minimum safety factor of 1.1 to determine the remaining service life or to schedule the next inspection.

In its response dated August 21, 2012, the applicant stated that the user defines the safety factor for FAC Manager Web Edition, and it uses a 1.1 safety factor in the calculations of remaining service life. The applicant also stated that it initiated a corrective action request to revise procedure EDP-ZZ-01115, to clarify that a safety factor of no less than 1.1 is to be used to calculate remaining service life. The staff finds the applicant's response acceptable because the applicant confirmed that it uses a safety factor of 1.1 to schedule a component's next inspection, which is consistent with the guidance given in NSAC-202L. In addition, the applicant initiated corrective actions to clarify this requirement in its implementing procedure. The staff's concern described in RAI B2.1.7-3 is resolved.

The "acceptance criteria" program element in GALL Report AMP XI.M17 states that if calculations indicate that an area will reach the minimum allowed wall thickness before the next scheduled outage, corrective action should be considered. During its review of plant-specific operating experience, the staff identified CAR 200403322, which stated that "this calculation decreased the design minimum thickness required by utilizing the measured ultimate tensile stress listed in the certified materials test report [(CMTR)]." In justifying the use of CMTR data during the staff's audit, the applicant's personnel provided engineering design guide, ME 013, "Pipewall Thickness," which states, "the use of CMTR data [in] lieu of using the published allowable stress for the material is permissible to further refine the minimum wall thickness analyses." The design guide defines the minimum wall thickness as the thickness that will meet the applicable code requirements for a given application and states that this process applies to ASME Code Class 2 and Class 3 and to American National Standards Institute (ANSI) B31.1 piping. Based on this, the staff questioned the applicant's acceptance criteria for meeting ASME Code minimum allowable wall thickness, since the ASME Code does not address the use of CMTR data for this purpose. By letter dated July 18, 2012, the staff issued RAI B2.1.7-5 requesting the applicant to provide information regarding its use of CMTR data to reduce the ASME Code-required minimum wall thickness during the period of extended operation.

In its response dated August 21, 2012, the applicant stated that the bases for determining the allowable stress limits are defined in ASME Code Section III, Appendix III, Article 3000, and would be applicable to situations where acceptance limits must be established for a material that is not listed in the stress tables. Based on this concept, the applicant stated that CMTR data can be applied when the documented material strength is greater than the minimum required strength for that particular standard and that use of CMTR data does not result in any reduction of conservatism. The applicant also stated that engineering evaluations performed on inservice components for reduced thickness or unanticipated loads are beyond the scope of ASME Code Section III and that such evaluations should be based on engineering judgment.

In its review of the applicant's response, the staff noted that in addition to the use of CMTR data for calculating the minimum wall thickness, engineering design guide ME-013 also specifies that the ASME Code allowable stresses may be increased by a factor of 1.1. The staff notes that this would result in a less conservative wall thickness, and there did not appear to be any restriction in combining the use of CMTR data with the additional stress increase. By letter dated October 12, 2012, the staff issued RAI B2.1.7-5a requesting the applicant to further clarify its use of CMTR data and to also address the apparent use of the 1.1 stress increase factor with respect to meeting the ASME Code requirements.

In its response dated November 8, 2012, the applicant stated that it had revised ME-013 to limit its applicability to operability determinations and evaluations of reduced wall thickness due to corrosion and erosion to support continued plant operation until repairs could be implemented. In addition, the applicant supplemented its response by letter dated December 20, 2013, and clarified that ME-013 is not used for the design of piping, piping systems, or components. The staff finds the response acceptable because the applicant clarified the applicability of ME-013 to ensure that current licensing bases regarding ASME Code minimum allowable wall thicknesses will be maintained during the period of extended operation. The staff's concerns described in RAI B2.1.7-5 and B2.1.7-5a are resolved.

Based on its audit of the applicant's Flow-Accelerated Corrosion Program and review of the applicant's responses to RAIs B2.1.7-1, B2.1.7-2, B2.1.7-3, B2.1.7-4, B2.1.7-4a, B2.1.7-5, and B2.1.7-5a, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M17.

Operating Experience. LRA Section B2.1.7 summarizes operating experience related to the Flow-Accelerated Corrosion Program. The LRA discussed the 1999 event for the rupture of a 6-inch drain line from a moisture separator reheater drain tank to high pressure feedwater heater. The applicant stated that, based on the small predicted wear rate from CHECWORKS™, the component was scheduled to be inspected during the next RFO. The applicant also stated that corrective actions for this event included the immediate inspections of 40 locations with similar geometry and fluid conditions, with no similar problem being identified. The staff noted that this event is cited in the GALL Report AMP XI.M17 as operating experience for this AMP. In addition, the LRA discussed the identification in 2001 of unexpected wall thinning in feedwater piping, which required expansion of the inspection scope and extensive replacement of the piping. According to the applicant, a personnel error caused these locations to not be modeled in CHECWORKS™. The staff noted that the associated CAR 200102270, was upgraded to a significance level 1, which required a formal root cause and extensive corrective actions to prevent recurrence.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant. 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 Callaway operating experience report, CAR 200500411, describes the failure of a flow venturi component due to FAC, which resulted in the blockage of downstream equipment. The flow meter's flow tube separated from its venturi throat and migrated down the pipe, blocking the minimum recirculation flow line. The applicant had inspected the spool piece containing the flow venturi in 2004 and had projected that it would last more than 50 years; however, the configuration of the flow element does not allow it to be inspected from the outside of the pipe using UT methods. The staff noted that this operating experience was unique because normal inspections cannot monitor the loss of material for the internal component, and failure of the flow venuri resulted in macrofouling, which is not an aging mechanism that is associated with the Flow-Accelerated Corrosion Program. Since this plant-specific operating experience is not bounded by the industry experience for which the GALL Report AMP XI.M17 was evaluated, by

letter dated July 18, 2012, the staff issued RAI B2.1.7-6 requesting the applicant to address whether this aging mechanism needs to be managed and, if so, how it intends to manage it and through which AMP.

In its response dated August 21, 2012, the applicant stated that it replaced the flow elements in both heater drain lines with an all stainless steel design and that the extent of condition identified five other locations with similarly designed flow elements. The applicant also stated that its corrective actions taken in response to CAR 200500411 are adequate to prevent failure of the flow elements and that the components identified during the extent of condition are not within the scope of license renewal. In its review of the response, the staff noted that the applicant issued an industry-wide operating-experience report in 2005 documenting the unexpected flow element failure. The staff finds the response acceptable because the applicant's corrective actions eliminated the concern for managing this plant-specific operating experience in all in-scope components. The staff's concern described in RAI B2.1.7-6 is resolved.

Based on its audit and review of the application and review of the applicant's response to RAI B2.1.7-6, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.M17 was evaluated.

FSAR Supplement. LRA Section A1.7 provides the FSAR supplement for the Flow-Accelerated Corrosion Program. The staff reviewed this FSAR 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 FSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Flow-Accelerated Corrosion 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 function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.7 Steam Generators

Summary of Technical Information in the Application. LRA Section B2.1.9, as amended by letter dated October 24, 2012, describes the existing Steam Generators Program as consistent with GALL Report AMP XI.M19, "Steam Generators." The LRA states that the Steam Generators Program manages cracking, loss of material, wall thinning, and loss of heat transfer of the steam generators; and that this program is applicable to the steam generator tubes, plugs, sleeves, and secondary side steam generator internal components. The LRA also states that aging is managed through assessment of potential degradation mechanisms, inspections, tube integrity assessments, plugging and repairs, primary to secondary leakage monitoring, maintenance of secondary side component integrity, primary side and secondary side water chemistry, and foreign material exclusion. The LRA further states that Callaway's procedural guidance implements the performance criteria for tube integrity, condition monitoring

requirements, inspection scope and frequency, acceptance criteria for the plugging or repairs of flawed tubes, acceptable tube repair methods, leakage monitoring requirements, operational leakage, and accident induced leakage requirements of applicant's TSs.

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 "preventive actions" program element, 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.M19 recommends preventive and mitigative actions for addressing degradation. Preventive and mitigative measures that are part of GALL Report AMP XI.M19 include foreign material exclusion programs and other primary and secondary side maintenance activities. The program should include foreign material exclusion as a means to inhibit wear degradation and secondary side maintenance activities, such as sludge lancing, for removing deposits that may contribute to degradation. Primary side preventive maintenance activities include replacing plugs made with corrosion susceptible materials with more corrosion resistant materials and preventively plugging tubes susceptible to degradation. Guidance on foreign material exclusion is provided in NEI 97-06, Revision 3, "Steam Generator Program Guidelines." Guidance on maintenance of secondary side integrity is provided in the EPRI document "Steam Generator Integrity Assessment Guidelines." During its audit, the staff found that the applicant's Steam Generators Program had several administrative inconsistencies when compared to the documents referenced by GALL Report AMP XI.M19. By letter dated July 5, 2012, the staff issued RAIs B2.1.9-1 through B2.1.9-6 requesting the applicant to address these inconsistencies. The staff's evaluation of the applicant responses to RAIs B2.1.9-1 through B2.1.9-6 is provided below.

The staff noted that NEI 97-06, Revision 3, was to be implemented by September 1, 2011. The TS for steam generator maintenance services (S-1032) was used for the RFO 18 steam generator tube inspections (which commenced after October 15, 2011). The staff noted that document S-1032, "Technical Specification for Steam Generator Maintenance Services," references NEI 97-06, Revision 2, in Section 4.2.A.4. By letter dated July 5, 2012, the staff issued RAI B2.1.9-1 requesting that the applicant discuss whether NEI 97-06, Revision 2, or NEI 97-06, Revision 3, was used during RFO 18 inspections. If NEI 97-06 Revision 2, was used, the staff requested that the applicant provide the deviation supporting this exception to the industry guidelines.

In its response dated August 6, 2012, the applicant stated that prior to RFO 18, document S-1032 was approved before the implementation of NEI 97-06, Revision 3. The applicant also stated that document S-1032 is a specification for a contractor to provide steam generator inspection services and is not used as a procedure to perform steam generator inspections. The applicant further stated that all implementation procedures for steam generator inspections conducted during RFO 18 references were governed by NEI 97-06 Revision 3, and future revisions of document S-1032 will reference NEI 97-06, Revision 3.

The staff finds the applicant's response acceptable because the applicant clarified that it followed the guidance in NEI 97-06, Revision 3, during its RFO 18 steam generator inspection which is consistent with the guidance provided in the GALL Report AMP XI.M19. The staff's concern described in RAI B2.1.9-1 is resolved.

The staff found that the term “active degradation” is used in EDP-BB-01341, “Steam Generator Surveillance.” This term, as originally defined, was misleading and is no longer used in the EPRI document, “Pressurized Water Reactor Steam Generator Examination Guidelines,” which were issued in 2007. By letter dated July 5, 2012, the staff issued RAI B2.1.9-2 requesting the applicant to discuss its plans for removing this term from its procedures.

In its response dated August 6, 2012, the applicant stated that EDP-BB-01341, “Steam Generator Surveillance,” procedure Sections 4.4.1.a.4, 4.9.6.c.3, 4.9.7.c, 4.9.7.e.3, 4.10.2.a, and 7.1 have been revised to remove references to the term "active degradation" and reference the term “existing degradation,” "degradation," or "degradation mechanism" to be consistent with EPRI 1019038, “Steam Generator Integrity Assessment Guidelines,” and EPRI 1013706, “Pressurized Water Reactor Steam Generator Examination Guidelines.”

The staff finds the applicant’s response acceptable because the applicant removed the term “active degradation” from EDP-BB-01341 procedure and replaced it with terms consistent with EPRI 1019038 and EPRI 1013706 which makes the applicant’s program consistent with the guidance provided in the GALL Report AMP XI.M19. The staff’s concern described in RAI B2.1.9-2 is resolved.

The staff noted that Section 4.1.2.c.3 of EDP-BB-01341, “Steam Generator Surveillance,” indicates that if implementation of a guideline change cannot be performed within 3 months of the due date, then a deviation should be processed. The staff finds that this appears to permit implementing the guideline change 3 months after the due date. By letter dated July 5, 2012, the staff issued RAI B2.1.9-3 requesting the applicant clarify where the 3-month “extension” is permitted by the industry guidelines (i.e., if the forwarding letter indicates the guideline change should be implemented by a specific date, it is not clear that a 3-month automatic extension is justified). If the 3-month “extension” is not permitted by industry guidance documents, the staff requested the applicant discuss its plans to change its procedures.

In its response dated August 6, 2012, the applicant stated that Section 4.1.2.c.3 of procedure EDP-BB-01341 has been revised to remove the 3-month extension for implementation of a guideline change and now states “IF implementation CANNOT be performed PROCESS a deviation.”

The staff finds the applicant’s response acceptable because its revision of procedure EDP-BB-01341 makes the applicant program consistent with the guidance provided in the GALL Report AMP XI.M19. The staff’s concern described in RAI B2.1.9-3 is resolved.

The staff noted that EDP-BB-01341 Section 4.5.1 deals with secondary side inspections; however, Section 4.5.1.a refers to primary side maintenance activities. By letter dated July 5, 2012, the staff issued RAI B2.1.9-4 requesting the applicant clarify if this was a typographical error.

In its response, dated August 6, 2012, the applicant stated that EDP-BB-01341 Section 4.5.1.a has been revised to correct a typographical error and reference the secondary side.

The staff finds the applicant’s response acceptable because the applicant clarified that it was a typographical error and revised EDP-BB-01341 Section 4.5.1.a accordingly which makes the applicant program consistent with the guidance provided in the GALL Report AMP XI.M19. The staff’s concern described in RAI B2.1.9-4 is resolved.

The staff noted that EDP-BB-01341 Section 4.10.3 requires the condition monitoring report to be completed within 30 days following completion of the outage; however EDP-BB-01341 Section 4.9.6.a.1 requires the condition monitoring report to be completed before Mode 4 after a steam generator inspection. The EPRI document "Steam Generator Integrity Assessment Guidelines" (Section 11.2.2) requires the condition monitoring assessment to be completed before entering Mode 4. By letter dated July 5, 2012, the staff issued RAI B2.1.9-5 requesting the applicant to discuss its plans to make its procedures consistent with the industry guidelines.

In its response dated August 6, 2012, the applicant stated that EDP-BB-01341 Section 4.10.3.c has been revised to ensure the condition monitoring report is completed before entering Mode 4.

The staff finds the applicant's response acceptable because its revision of EDP-BB-01341 Section 4.10.3.c makes the applicant program consistent with the guidance provided in GALL Report AMP XI.M19. The staff's concern described in RAI B2.1.9-5 is resolved.

The staff noted that EDP-BB-01341 Section 4.8.5.e refers to "degradation of interest" rather than "existing and potential degradation," as discussed in the EPRI document, "Steam Generator Integrity Assessment Guidelines" (Section 6.2). By letter dated July 5, 2012, the staff issued RAI B2.1.9-6 requesting the applicant discuss whether "degradation of interest" is defined in its procedures. If not, the staff requested the applicant to discuss its plans to modify its procedures to ensure they are consistent with the industry guidelines.

In its response, dated August 6, 2012, the applicant stated that the EDP-BB-01341 Section 4.8.5.e has been revised to refer to existing and potential degradation mechanisms and now states, "IDENTIFY the limiting structural integrity performance criteria and the appropriate loading conditions for existing and potential degradation mechanisms (i.e. 3 Delta P vs. 1.4 times accident pressure including primary vs. secondary loading)."

The staff finds the applicant's response acceptable because the applicant revised EDP-BB-01341 Section 4.8.5.e to make it consistent with EPRI guidelines, and this makes the applicant program consistent with the guidance provided in the GALL Report AMP XI.M19. The staff's concern described in RAI B2.1.9-6 is resolved.

Based on its audit of the applicant's Steam Generators Program and review of the applicant's responses to RAIs B2.1.9-1 through B2.1.9-6, 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.

Operating Experience. LRA Section B2.1.9 summarizes operating experience related to the Steam Generators Program. The LRA states, in part, the following regarding operating experience:

> [d]uring [RFO] 14 (Fall 2005), [steam generators] were replaced with AREVA designed steam generators with alloy 690 thermally treated tubes. Pre-service eddy current inspections found 77 small dings, four tubes with signals similar to outside diameter axial cracking, and 33 tubes with a spiral signal pattern. After analyzing the signals and the tubes containing indications, the tubes were found to have no detectable degradation. One tube was plugged due to manufacturing defects. Visual inspections of the [steam generator] secondary side were performed to identify any foreign objects that may have been left behind after up righting and installation of the steam generators. Several foreign objects were

> found during these inspections and removed prior to placing the steam generators in service.

The LRA states that during RFO 15 (spring 2007), the first ISI of the new steam generators identified a total of 92 anti-vibration bar (AVB) wear indications. The LRA also states that the largest indication was a 14 percent through-wall flaw. The LRA further states that, consistent with Callaway's RFO 15 operational assessment, the structural integrity performance criteria for AVB wear is not expected to be exceeded before the next scheduled steam generator inspection in RFO 18 (fall 2011).

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.

The staff noted that that AREVA NP Inc., document No. 51-9172264-000, "Callaway Unit 1 SG [Steam Generator] Condition Monitoring for Cycles 16, 17, and 18 and Final Operational Assessment for Cycles 19, 20, and 21," does not appear to justify the length of the operating interval for secondary side degradation. The staff also noted that Section 10.3 of the EPRI document, "Steam Generator Integrity Assessment Guidelines," indicates that the operational assessment shall include a justification for operating the planned interval between secondary side inspections, as well as primary side inspections. By letter dated July 5, 2012, the staff issued RAI B2.1.9-7 requesting the applicant discuss whether there is a justification for the planned operating interval that addresses degradation of secondary side internals.

In its response, dated August 6, 2012, as supplemented by letter dated September 18, 2012, the applicant stated that the following:

> The first paragraph of Section 10 of [AREVA NP, Inc.,] document 51-9172264-00 identifies the forms of degradation detected in the Callaway Unit-1 replacement steam generators at the 1R18 outage [RFO 18]. These mechanisms were AVB and TSP [tube support plate] wear. There was no degradation associated with the secondary side findings (inner bundle or steam drum).

The applicant stated that the intent of the operational assessment was to address currently detected and/or previously detected degradation mechanisms located on the primary and secondary sides of the steam generators. The applicant also stated the secondary side findings revealed no degradation, and, therefore, discussion was limited to the condition monitoring results located in Section 6.2 of AREVA NP Inc., document 51-9172264-00.

The applicant stated that AREVA NP Inc., document No. 51-9172264-00 Section 6.2 identifies the secondary side activities performed in RFO 18. These activities included steam drum inspections in steam generators B and C, foreign object and possible loose part (PLP) inspections in all four steam generators, and sludge lancing in all four steam generators. The applicant stated that no loose part or loose hardware was detected in the steam drum of either steam generator as a result of the steam drum inspections. The applicant also stated that the only anomaly noted was a pre-existing condition which consisted of two buckles on one of the sectors associated with the loose part trapping screens. The applicant further stated that

foreign object and possible loose part inspections revealed no possible loose parts or foreign object degradation detected in any steam generator based on eddy current inspections. In addition, the applicant stated that only a small piece of scale in the cold-leg of steam generator A was detected by the foreign object search and retrieval inspections (post-lancing) and only minimal amounts of sludge were contained within each of the four steam generators as revealed by the sludge lancing results. The applicant stated that "the findings at [RFO] 18 echoed the findings at [RFO] 15 (with exception of the single small piece of scale detected in the cold leg of [steam generator] A)" and concluded that "[b]ased on two consecutive outages of exceptional secondary side inspection results, any projected secondary side degradation is expected to be minimal and to not compromise tube integrity for the planned operating interval."

In its supplemental response dated September 18, 2012, the applicant stated that it is updating the steam generator surveillance procedure to explicitly state the requirement for the condition monitoring report to include projection data to justify operation for the planned interval between secondary side inspections and that this includes degradation of secondary side internals.

The staff reviewed the applicant response as supplemented and finds it acceptable because the applicant's assessment of the secondary side component degradation is in line with industry guidance. Furthermore, revising the steam generator surveillance procedure to more accurately reflect the guidance in the EPRI document, "Steam Generator Integrity Assessment Guidelines," will ensure that a justification for the planned operating interval will include secondary side component degradation in the applicant's condition monitoring reports for the future. The staff's concern described in RAI B2.1.9-7 is resolved.

The staff noted that Section 8.6 of the EPRI document, "Steam Generator Integrity Assessment Guidelines," indicates, in part, that (1) failure to meet condition monitoring requirements means that the projections of the previous operational assessment were not conservative and that necessary corrective actions shall be identified; and (2) even if condition monitoring requirements are met, a comparison of condition monitoring results with the projections of the previous operational assessment shall be performed, and this comparison shall be completed before issuance of the final operational assessment since adjustment of input parameters may be required. AREVA NP Inc., Document No. 51-9172264-000, "Callaway Unit 1 SG [Steam Generator] Condition Monitoring for Cycles 16, 17, and 18 and Final Operational Assessment for Cycles 19, 20, and 21," states that the latter must be performed, but then the report went on to indicate that the assumptions and uncertainties included in the previous operational assessment are validated since none of the detected indications approach the condition monitoring limit and that additional discussions below provide further details. The staff could not locate these additional discussions. In addition, in reviewing the previous operational assessment, the staff could not locate any specific projections such that a comparison of the as-found and previously projected conditions could be compared. It is not clear to the staff that the intent of the EPRI requirement has been met. The staff noted that the operational assessment is supposed to be conservative. As a result, even if the actual detected conditions are near (including "slightly" below) the projections from the prior operational assessment, this could indicate a potential nonconservative assessment that may lead to issues in the future if not corrected. By letter dated July 5, 2012, the staff issued RAI B2.1.9-8 requesting the applicant clarify these discrepancies.

In its response dated August 6, 2012, the applicant stated that additional discussions, although not specifically referenced, are located in Section 7.2, "Structural Results," and Section 7.3, "Leakage Results," of AREVA NP Inc., Document No. 51-9172264-000, "Callaway Unit 1 SG [Steam Generator] Condition Monitoring for Cycles 16, 17, and 18 and Final Operational

Assessment for Cycles 19, 20, and 21." Furthermore, the applicant stated that the implied projections of the RFO 15 operational assessment (both growth rates and end of cycle percent through wall) were satisfied with adequate margin, at end of cycle 18, as demonstrated by the condition monitoring results. In a supplemental response dated September 18, 2012, the applicant stated that "[t]he Callaway's steam generator surveillance procedure is being updated to explicitly state the requirement for the [c]ondition [m]onitoring report to include a definitive comparison between the current condition monitoring results with the projections of the previous operational assessment."

The staff reviewed the applicant's response as supplemented and finds it acceptable because the applicant's assessment of the structural results, leakage results, and operational assessment meet the industry guidance as provided by EPRI. Furthermore, revising the Steam Generator Surveillance procedure to ensure that the condition monitoring report more accurately reflects the guidance in the EPRI document, "Steam Generator Integrity Assessment Guidelines," will ensure that a definitive comparison between the current condition monitoring results with the projections of the previous operational assessment and that the comparison will be documented in the applicant's condition monitoring reports in the future. The staff's concern described in RAI B2.1.9-8 is resolved.

Based on its audit and review of the application, and review of the applicant's responses to RAIs B2.1.9-7 and B2.1.9-8, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience, and that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.M19 was evaluated.

FSAR Supplement. LRA Section A1.9 provides the FSAR supplement for the Steam Generators Program. The staff reviewed this FSAR 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 FSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Steam Generators 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 function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.8 One-Time Inspection

Summary of Technical Information in the Application. LRA Section B2.1.18 describes the new One-Time Inspection Program as consistent with GALL Report AMP XI.M32, "One-Time Inspection." The LRA states that the One-Time Inspection Program verifies the system-wide effectiveness of the Water-Chemistry, Fuel Oil, and Lubricating Oil Analysis programs through the use of inspections to confirm that aging effects are either not occurring or are progressing so slowly as to have a negligible effect on the intended function of each component.

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.M32. Based on its audit of the applicant's One-Time 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.M32.

Operating Experience. LRA Section B2.1.18 summarizes operating experience related to the One-Time Inspection Program. The LRA states that a review of 10 years of operating experience associated with the Water Chemistry, Fuel Oil, and Lubricating Oil Analysis programs confirmed that aging effects are either not occurring or are progressing so slowly as to have a negligible effect on the intended function of each component and are adequately managing aging effects. The LRA also states that RPV inservice inspections revealed an original construction weld flaw in the "C" inlet nozzle of the RPV and ongoing monitoring of this flaw will use state-of-the-art NDE techniques. The LRA further states that these examples demonstrate that inspections associated with this program will be capable of detecting and identifying aging effects before a loss of intended function during the period of extended operation.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant. 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 GALL Report AMP XI.M32 was evaluated.

FSAR Supplement. LRA Section A1.18 provides the FSAR supplement for the One-Time Inspection Program. The staff reviewed this FSAR 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. 14) to implement the new One-Time Inspection Program six months before entering the period of extended operation.

The staff finds that the information in the FSAR supplement, as amended by letter dated February 28, 2013, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's One-Time Inspection Program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff concludes that the applicant 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 FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.9 One-Time Inspection of ASME Code Class 1 Small-Bore Piping

Summary of Technical Information in the Application. LRA Section B2.1.20 describes the new One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program as consistent with GALL Report AMP XI.M35, "One-Time Inspection of ASME Code Class 1 Small-Bore Piping." The LRA states that the program manages cracking of ASME Code Class 1 piping less than 4 in. and greater than or equal to 1-inch nominal pipe size (NPS) in a reactor coolant environment.

The LRA states that there are 340 ASME Code Class 1 small-bore butt welds within the scope of the program at the applicant's facility. The LRA states that at least 25 butt welds will be included in the examination population. The LRA also states that the program will include a volumetric or opportunistic destructive examination of socket welds and butt welds to identify potential cracking. The LRA further states that two small-bore ASME Code Class 1 socket welds will be selected for examination, which represents 10 percent of the population of 19 socket welds covered by the program. In addition, the LRA states that for socket welds, if a demonstrated volumetric examination technique endorsed by industry or the NRC, and incorporated into ASME Code Section XI is not available by the time of the inspections, then a qualified plant procedure for volumetric examination of ASME Code Class 1 small-bore piping socket welds will be used. The LRA also states that the program includes implementation of a plant-specific periodic inspection AMP, should evidence of ASME Code Class 1 small-bore piping cracking be confirmed by review of plant-specific operating experience.

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.M35. 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.

LRA Section B2.1.20 originally stated that there were 19 Class 1 small-bore socket welds in the population of ASME Code Class 1 piping less than NPS 4 and greater than or equal to NPS 1. However, during the audit the applicant stated that its recount, performed subsequent to the LRA submission, had indicated that there were 23 Class 1 small-bore socket welds within the scope of the program. The staff noted that recent review of LRAs of other similar facilities have shown the number of in-scope socket welds to be significantly greater than 19 or 23. By letter dated July 18, 2012, the staff issued RAI B2.1.20-1 requesting that the applicant clarify the total population of ASME Code Class 1 socket welds within the scope of the program.

In its response dated August 21, 2012, the applicant stated that there are 77 small-bore socket welds in the scope of the AMP. The applicant also amended LRA Sections B2.1.20 and A1.20 to reflect the correct number of socket welds. In addition, the applicant revised the AMP to indicate that eight small-bore Class 1 socket welds will be inspected. During its review of the applicant's revised AMP the staff noted that the revised LRA is not clear on how each destructive test will be credited. Specifically, if the applicant chooses to perform opportunistic destructive examinations on socket welds in lieu of volumetric examinations, it is not clear to the staff what the ratio of those tests will be. GALL Report AMP XI.M35 states that when opportunistic destructive examinations are used for socket welds, the applicant may take credit for each weld destructively examined as equivalent to having volumetrically examined two welds. By letter dated October 3, 2012, the staff issued RAI B2.1.20-1a, requesting that the applicant clarify how each destructive test will be credited and also when and if opportunistic destructive examinations are included in the applicant's AMP.

In its response dated October 31, 2012, the applicant stated that, consistent with the guidance provided in the GALL Report, it will credit each destructive examination of a socket weld as equivalent to having volumetrically examined two. As part of its response, the applicant amended LRA Sections B2.1.20 and A1.20 to specifically state that when opportunistic destructive examinations are used, each destructive examination will be considered equivalent to having volumetrically examined two welds. The staff finds the applicant's response acceptable because it clarified that, if opportunistic destructive tests are performed, each destructive test will be credited as having performed two volumetric examinations, consistent with the GALL Report. The staff's concern described in RAI B2.1.20-1a is resolved.

During a telephone conference call held on April 11, 2013, the staff requested the applicant to explain the reasons for the large discrepancy between the different counting results for the number of socket welds, and whether any error in the process has been corrected. The applicant stated that the information would be provided to the staff in a supplemental response to RAI B2.1.20-1. The applicant's need to explain the discrepancy between the different counting results was identified as OI B2.1.20-1.

By letter dated April 16, 2013, the applicant supplemented its response to RAI B2.1.20-1. The supplemental response provided an explanation of how the error occurred during counting the number of socket welds. In its response, the applicant stated that the list of socket welds was developed from its Inservice Inspection database, using the fields for ASME Category and Item Number. The error occurred because some small-bore socket welds were not assigned any ASME Category and Item Numbers since they are exempt from ASME Code Section XI ISI volumetric and surface examinations. The staff noted that a similar error could have also occurred when counting in-scope items for other aging management programs in the LRA. By letter dated July 12, 2013, the staff issued followup RAI B2.1.20-2, requesting that the applicant verify that the issue of reporting the incorrect number of socket welds was entered in its corrective actions program, or justify why a similar error could not and did not occur elsewhere in the LRA.

In its response dated August 2, 2013, the applicant stated that the issue of reporting the incorrect number of ASME Code Class 1 small-bore socket welds in the LRA was entered in the applicant's Corrective Action Program as an adverse condition. The applicant also stated that an extent of condition review was performed. Since the error was introduced during the process of developing a sample population, the extent of condition for the error was determined to include all instances where sample population numbers are cited in the LRA, and the applicant searched for instances of sample, sampling, and population. The applicant further stated that this search only provided two instances where sample population was developed in support of an AMP and cited in the LRA, and that both instances were related to the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program. The applicant also stated that the number of butt welds and socket welds were reconfirmed for accuracy; the examination population remained unchanged at 25 butt welds and 8 socket welds. The staff finds the applicant's response acceptable because: (1) the applicant entered the error in its Corrective Action Program; (2) the applicant's extent of condition for the error verified that a similar error had not occurred elsewhere in the LRA; and (3) as part of corrective actions the applicant re-counted the total number of in-scope butt welds and socket welds and confirmed the numbers. The staff's concern described in RAI B2.1.20-2 is resolved. The staff concludes that the concerns identified in OI B2.1.20-1 have been resolved. Open Item B2.1.20-1 is closed.

Based on its audit of the applicant's One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program and review of the applicant's responses to RAIs B2.1.20-1, B2.1.20-1a, and

B2.1.20-2, the staff finds that program elements 1 through 6, for which the applicant claimed consistency with the GALL Report, are consistent with the corresponding program elements of GALL Report AMP XI.M3.

Operating Experience. LRA Section B2.1.20 summarizes operating experience related to the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program. The LRA states that in 1995 cracking was observed on an ASME Code Class 1 small-bore pipe butt weld less than NPS 4. Specifically, a Class 1 butt weld on a 2-inch CVC system excess letdown line developed a crack. The reported failure was attributed to high stresses because of interference and system vibrations. As part of its corrective actions, the applicant removed the interference and subsequent volumetric examinations performed in 2010 that did not identify any indication. The applicant also stated that there have been no additional failures of ASME Code Class 1 small-bore piping since 1995.

The staff noted that the applicant has performed design changes to mitigate the cause of the reported failure, and performed additional inspections to determine the extent of condition. In addition, there have been no additional similar failures of ASME Code Class 1 small-bore piping welds since the implementation of the applicant's corrective actions. Therefore, consistent with GALL Report AMP XI.M35, the use of the applicant's One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program is appropriate, because the reported failure of 1995 was successfully mitigated.

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 GALL Report AMP XI.M35 was evaluated.

FSAR Supplement. LRA Section A1.20 provides the FSAR supplement, as amended by letters dated August 21, 2012, October 31, 2012, and February 28, 2013, for the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program. The staff reviewed this FSAR 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. 16) to implement the new One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program six months before entering the period of extended operation.

The staff finds that the information in the FSAR supplement, as amended by letters dated August 21, 2012, October 31, 2012, and February 28, 2013, is an adequate summary description of the program.

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 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 function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.10 External Surfaces Monitoring of Mechanical Components

Summary of Technical Information in the Application. LRA Section B2.1.21 describes the new External Surfaces Monitoring of Mechanical Components Program as consistent with GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components." The LRA states that the AMP manages loss of material and cracking for metallic components; cracking and changes in material properties for cement board; and loss of material, cracking, changes in material properties, hardening, and loss of strength for polymeric components. The LRA also states that the AMP proposes to manage these aging effects using visual inspections that are performed at least every RFO for normally accessible locations. In addition, the LRA states that manual or physical manipulation will supplement visual inspections to identify aging effects for polymeric components. The LRA further states that surfaces not readily visible during plant operations and RFO are inspected when they are made accessible and at intervals that would ensure the components' intended functions are maintained.

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. Based on its audit of the applicant's External Surfaces Monitoring of Mechanical Components 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.

Operating Experience. LRA Section B2.1.21 summarizes operating experience related to the External Surfaces Monitoring of Mechanical Components Program. The LRA states that cracking was found in 2006 on a rubber expansion joint between ESW piping and the diesel generator intercooler heat exchanger. The joints between the components were replaced and the maintenance procedure for the heat exchanger tubes was revised to include inspections of the expansion joints. The LRA also states that loss of material was identified on ESW supply line piping in 2006. The LRA further states that ultrasonic testing determined that the piping met minimum wall thickness. The piping coating was completely restored on all bare metal surfaces of piping related to this finding.

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 which resulted in the issuance of an RAI, as discussed below.

LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," revised GALL Report AMP XI.M36 to address recent industry operating experience associated with corrosion under insulation. For insulated outdoor components and insulated indoor components operated below the dew point, GALL

Report AMP XI.M36 was revised to recommend that an initial representative sample of external surfaces be inspected after the insulation is removed. If the initial examinations do not reveal evidence of component aging, water intrusion, or damage to the insulation, the revised guidance allows for subsequent examinations to focus only on indications of damage to the insulation jacketing or protective outer layer rather than removing the insulation. By letter dated October 7, 2013, the staff issued RAI 3.0.3-5, requesting that the applicant describe how corrosion under insulation would be managed for insulated outdoor components and insulated indoor components operated below the dew point.

In its response dated December 20, 2013, as supplemented by letter dated March 13, 2014, the applicant stated that the External Surfaces Monitoring of Mechanical Components Program will include all of the new inspection recommendations in LR-ISG-2012-02 associated with corrosion under insulation. The staff finds the applicant's response acceptable because the applicant incorporated the new inspection guidance provided in LR-ISG-2012-02, such that the External Surfaces Monitoring of Mechanical Components Program will be consistent with the revised GALL Report AMP XI.M36. The staff's concern described in RAI 3.0.3-5 is resolved.

Based on its audit, review of the application, and review of the applicant's response to RAI 3.0.3-5, 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 GALL Report AMP XI.M36 was evaluated.

FSAR Supplement. LRA Section A1.21 provides the FSAR supplement for the External Surfaces Monitoring of Mechanical Components Program. The staff reviewed this FSAR 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 External Surfaces Monitoring of Mechanical Components Program six months before entering the period of extended operation for managing aging of applicable components during the period of extended operation. The staff finds that the information in the FSAR supplement, as amended by letter dated February 28, 2013, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's External Surfaces Monitoring of Mechanical 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 function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.11 Flux Thimble Tube Inspection

Summary of Technical Information in the Application. LRA Section B2.1.22 describes the existing Flux Thimble Tube Inspection Program as consistent with GALL Report AMP XI.M37, "Flux Thimble Tube Inspection." The LRA states that the Flux Thimble Tube Inspection 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 LRA also states that the eddy current testing is performed on the portion of the tubes inside the reactor vessel. The LRA further states that the AMP implements the recommendations of NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors." The LRA states that the flux thimble tubes are

inspected during each RFO and that inspection may be deferred by using an evaluation that considers the actual wear rate. The LRA further states 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 before the next RFO, corrective actions are taken to reposition, cap, or replace the tube.

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.M37. The staff also reviewed the plant conditions to determine if they are bounded by the conditions for which the GALL Report was evaluated.

The LRA states that the applicant's reactor vessel lower internals have instrumentation column sleeves installed that reduce the instrument column inside diameter. The flux thimble tubes have an outer diameter of 0.313 in. The combination of reduced inside diameter of the instrument columns and large outer diameter of the flux thimble tubes results in a smaller annular gap. The smaller gap minimized tube vibration fretting wear and, therefore, reduced wear rates. The staff noted that based on industry experience as documented in Westinghouse Commercial Atomic Power (WCAP)-12866, "Bottom Mounted Instrumentation Flux Thimble Wear," the existing configuration of the applicant's flux thimble tubes has very low wear rates, as a result of the minimal clearance between the instrument column and the tube. This is consistent with the applicant's operating record that no flux thimble tubes have been removed from service or repositioned due to wear during the past 25 years of plant operation.

The LRA also states 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 staff noted that the applicant's Flux Thimble Tube Inspection Program is an existing program that is based on the recommendations in NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors." The staff also noted that the applicant's program trends wall thickness measurements and calculates actual wear rates. 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 before the next RFO, corrective actions are taken to reposition, cap, or replace the tube. The staff finds that the continued implementation of the Flux Thimble Tube Inspection Program provides reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions.

Based on its audit, and review of the applicant's Flux Thimble Tube 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.M37.

Operating Experience. LRA Section B2.1.22 summarizes operating experience related to the Flux Thimble Tube Inspection Program. The LRA states that the applicant had to reposition flux thimble tubes only twice because of reasons other than wear. In one case, a thimble tube was repositioned because detectors could not be inserted past the seal table. In the second case, a thimble tube was repositioned because of galled fittings and because installation of new fittings required the thimble tube to be repositioned. During the review and onsite audit, the staff reviewed details of the two cases and confirmed that the repositioning was not caused by wear. The staff also reviewed the operating history and inspection results of the applicant's Flux

Thimble Tube Inspection Program and noted that the applicant has not experienced any wear-related failures in its flux thimble 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, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.M37 was evaluated.

FSAR Supplement. LRA Section A1.22 provides the FSAR supplement for the Flux Thimble Tube Inspection Program. The staff reviewed this FSAR 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 FSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Flux Thimble Tube Inspection Program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff concludes that the applicant 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 FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.12 ASME Code Section XI, Subsection IWL

Summary of Technical Information in the Application. LRA Section B2.1.27 describes the existing ASME Section XI, Subsection IWL Program as consistent with GALL Report AMP XI.S2, "ASME Section XI, Subsection IWL." The LRA states that the ASME Section XI, Subsection IWL Program addresses concrete of containment building and post-tensioning system exposed to atmosphere and weather to manage the aging effects of cracking, loss of material, loss of bond, loss of strength, and increase in porosity and permeability through visual inspections, supplemented by testing.

The LRA states that acceptance criteria, corrective actions, and expansion of the inspection scope, when degradation exceeding the acceptance criteria is found, are performed in accordance with ASME Code Section XI, Subsection IWL. The LRA states that the IWL containment inservice inspections satisfy the requirements of the 2001 Edition of ASME Code Section XI (including 2002 and 2003 addenda), supplemented with the applicable requirements of 10 CFR 50.55a(b)(2). In conformance with 10 CFR 50.55a(g)(4)(ii), the Callaway Containment Inservice Inspections 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.

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. For the "acceptance criteria" program element, the staff determined the need for additional information, which resulted in the issuance of an RAI as discussed below.

GALL Report AMP XI.S2, "ASME Section XI, Subsection IWL," program element six, "acceptance criteria," recommends that the program use acceptance criteria provided in IWL-2510, which references American Concrete Institute (ACI) 201.1R and ACI 349.3R for identification of concrete degradation. The LRA AMP basis document for program element six, "acceptance criteria," states that Callaway acceptance criteria for concrete degradation is in accordance with IWL-2510, and consistent with ACI 201.1R and ACI 349.3R.

However, during its onsite audit, the staff reviewed plant procedures applicable to the applicant's IWL Program and could not find a reference to ACI 349.3R in any plant procedures. The staff also reviewed results of previous IWL examinations and noted that the evaluation criteria specified in ACI 349.3R Chapter 5, "Evaluation Criteria," were not used during the examinations of the concrete containment building.

By letter dated July 9, 2012, the staff issued RAI B2.1.27-1 requesting that the applicant state whether plant procedures reference ACI 349.3R, and if so, how the procedures incorporate the guidance in ACI 349.3R. Also, the staff requested that the applicant provide clarification on whether the evaluation criteria specified in ACI 349.3R Chapter 5 are used during IWL examinations or that they provide justification for not using the ACI 349.3R criteria during the examinations of the concrete containment building.

In its response dated August 9, 2012, the applicant stated that LRA Appendix B2.1.27 was revised and LRA Table A4-1, Commitment No. 40 was added as a new commitment to specify that acceptability of concrete surfaces is based on the evaluation criteria provided in ACI-349.3R. The applicant also revised LRA Section B2.1.27 to include a new enhancement to the "acceptance criteria" program element. In this enhancement, the applicant stated that plant procedures will be enhanced to specify that acceptability of concrete surfaces is based on the evaluation criteria provided in ACI-349.3R."

The staff reviewed the RAI response and the new enhancement against the corresponding program element in GALL Report AMP XI.S2 and finds the response and the enhancement acceptable because when implemented it will align the applicant's acceptance criteria with that provided in ACI 349.3R-96, and recommended in GALL Report AMP XI.S2. The staff finds that the applicant's enhanced "acceptance criteria" program element will be consistent with the GALL Report program element. The staff's concern described in RAI B2.1.27-1 is resolved.

Based on its audit of the applicant's ASME Section XI, Subsection IWL Program and review of the applicant's response to RAI B2.1.27-1, 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.S2.

Operating Experience. LRA Section B2.1.27 summarizes operating experience related to the ASME Section XI, Subsection IWL Program.

The applicant provided the following discussion of operating experience that offers objective evidence that the ASME Section XI, Subsection IWL Program will be effective in ensuring that intended functions are maintained consistent with the CLB for the period of extended operation:

(1) The 15th year tendon surveillance began in May 1999 and was completed in June 1999. Based on the data gathered during the 1999 physical surveillance and visual inspection, the conclusion was reached that no abnormal degradation of the post-tensioning system had occurred at the Callaway containment building.

(2) The 20th year tendon surveillance began in July 2004 and was completed in September 2004. All tendons were resealed and regreased. One tendon accepted less grease than was removed, and one tendon accepted more than 10 percent of the tendon duct volume. Nonconformance reports were written to record these findings and these conditions were found to be acceptable by engineering evaluation, as allowed by ASME [Code] Section XI, Subsection IWL-3310. Based on these evaluations and the other data gathered during the 2004 physical surveillance and visual inspection, the conclusion was reached that no abnormal degradation of the post-tensioning system had occurred at the Callaway containment building.

(3) The 25th year tendon surveillance began in March 2010 and was completed in April 2010. Sample wires were removed from one tendon in each group for physical testing. The test results on one of the wire samples indicated elongation values under the minimum prescribed in Callaway specifications. A nonconformance report was written to record this finding, and this condition was found to be acceptable by engineering evaluation, as allowed by ASME [Code] Section XI, Subsection IWL-3310. Based on this evaluation and the other data gathered during the 2010 physical surveillance and visual inspection, the conclusion was reached that no abnormal degradation of the post-tensioning system had occurred at the Callaway containment building.

Furthermore, the applicant stated that "[o]ccurrences that would be identified under the ASME Section XI, Subsection IWL Program will be evaluated to ensure there is no significant impact to safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance for re-evaluation, repair, or replacement is provided for locations where aging is 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 also 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.

GALL Report AMP XI.S2, "ASME Section XI, Subsection IWL," program element 10, "operating experience," references NUREG-1522, "Assessment of Inservice Condition of Safety-Related Nuclear Power Plant Structures," dated June 1995. NUREG-1522 describes instances of cracked, spalled, and degraded concrete for reinforced and prestressed concrete containments. During the staff's onsite walkdown on May 2, 2012, mapped cracks in concrete were identified around the vertical tendon casings in the tendon gallery.

Callaway's 25th year containment IWL inspection report identified the referenced cracks as "hair-line cracks," less than 0.040 in. in width. The second-tier evaluation criteria of ACI 349.3R is 0.04 in. for "passive cracks." It is not clear to the staff whether those cracks were determined to be "passive cracks," and whether the "Evaluation Criteria" of ACI 349.3R was used to

evaluate the findings. ACI 349.3R defines passive cracks as those having an absence of recent growth and an absence of other degradation mechanisms at the crack.

By letter dated July 9, 2012, the staff issued RAI B2.1.27-2 requesting that the applicant provide justification regarding whether the mapped cracks in concrete around the vertical tendon casings in the tendon gallery are "passive cracks" and provide the evaluation criteria used for accepting those conditions.

In its response dated August 9, 2012, the applicant stated that "[t]he 20th year IWL inspection report noted concrete cracks less than 0.010 in. surrounding the bearing plates. The 25th year IWL inspection report also noted concrete cracks less than 0.010 in. surrounding the bearing plates." The applicant also stated that there is no indication that these cracks have experienced any recent growth, and the inspections have not identified any other degradation mechanisms at the cracks. Therefore, the applicant identified these cracks as passive. Furthermore, the applicant stated that:

> [t]he 25th year IWL inspection report contains the vendor's procedure that specifies the inspection criteria. This procedure specifies that visual examinations will identify concrete deterioration and distress as defined in ACI 201.1 and ACI 349.3R. The section of the 25th year inspection report that noted cracks less than 0.040 inches was the general visual examination performed on the exterior surface of the containment. Describing the cracks as "less than 0.040 inches" denotes that they do not exceed the second-tier limits provided in ACI 349.3R. These cracks were then inspected with a detailed visual examination and found to be less than 0.010 inches in width and, therefore, within the first-tier limits of ACI 349.3R and require no further evaluation.

The staff finds the applicant's response acceptable because acceptance criteria of the ASME Section XI, Subsection IWL Program at Callaway is consistent with that provided in ACI 349.3R-96, and, therefore, is consistent with GALL Report XI.S2 acceptance criteria. In addition, the identified cracking was below the first tier acceptance criteria; therefore, additional evaluation was unnecessary. The applicant also inspected the cracks during two consecutive inspections (5-year interval) and did not identify any change in the crack width, which indicates the cracks are passive. In addition, the applicant will continue to inspect these areas every 5 years during the period of extended operation and if any degradation is found the applicant will evaluate the indications and incorporate them into the CAP. The staff finds that this is consistent with the ASME Section XI, Subsection IWL Program. Therefore, the staff's concern described in RAI B2.1.27-2 is resolved.

During its walkdown on May 2, 2012, the staff observed the exterior section of the containment structure at various elevations and noted that the containment vent duct installation was blocking a section of the containment exterior surface. The staff could not determine how the area of concrete that is obstructed by the containment vent duct installation has been or will be visually inspected in accordance with the code.

By letter dated July 9, 2012, the staff issued RAI B2.1.27-3 requesting that the applicant describe how the area of concrete containment that is obstructed by the containment vent duct has been or will be examined during the scheduled IWL inspections to ensure that the effects of aging of the containment concrete are adequately managed.

In its response dated August 9, 2012, the applicant stated that in accordance with 10 CFR 50.55a(b)(2)(viii)(E), ASME Section XI, Subsection IWL Program requires:

> [t]hat if concrete inspections determine that conditions exist in accessible areas that could indicate the presence of or result in degradation to inaccessible areas, for each inaccessible area identified, the following information shall be provided in the owner's activity report:
>
> (a) [d]escription of the type and estimated extent of degradation, and the conditions that led to the degradation
>
> (b) [e]valuation of each area, and the result of the evaluation
>
> (c) [d]escription of necessary corrective actions

Furthermore, the applicant stated that a review of ASME Section XI, Subsection IWL Program inspection reports indicates that no conditions exist in accessible areas that could indicate the presence of degradation in inaccessible areas.

The staff finds the applicant's response acceptable because ASME Section XI, Subsection IWL Program inspection reports do not identify conditions in accessible areas that may indicate the presence of degradation in inaccessible areas. In the future, if degradation is identified in accessible areas that indicates the potential presence of degradation in inaccessible areas, the applicant will evaluate the indications and enter them into the CAP as necessary. The staff finds that this practice aligns with the guidance in GALL Report AMP XI.S2. The staff's concern described in RAI B2.1.27-3 is resolved.

Based on its audit, review of the application and review of the applicant's responses to RAIs B2.1.27-2 and B2.1.27-3, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience, and that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.S2 was evaluated.

FSAR Supplement. LRA Section A1.27 provides the FSAR supplement for the ASME Section XI, Subsection IWL Program. The staff reviewed this FSAR 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 enhance, six months before the period of extended operation, the ASME Section XI, Subsection IWL program to specify that acceptability of concrete surfaces is based on the evaluation criteria provided in ACI-349.3R. The staff finds that the information in the FSAR supplement, as amended by letter dated February 28, 2013, 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 IWL 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 function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.13 10 CFR Part 50, Appendix J

Summary of Technical Information in the Application. LRA Section B2.1.29 describes the existing 10 CFR Part 50, Appendix J Program as consistent 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, loss of leak tightness, loss of sealing, and loss of preload to ensure leakage through the primary containment, and systems and components penetrating the primary containment, does not exceed allowable leakage rate limits specified in the TS. The LRA also states that the program does not prevent degradation due to aging effects but provides measures for monitoring to detect the degradation before the loss of intended function. Periodic monitoring of leakage from the containment, containment isolation valves, and containment penetrations ensures proper maintenance and repairs can be performed before the loss of intended function. The LRA further states that the program is in accordance with the rule and guidance provided in 10 CFR Part 50 Appendix J, Option B, NRC Regulatory Guide (RG) 1.163, "Performance-Based Containment Leak-Test Program," NEI 94-01, "Industry Guideline for Implementing Performance Based Option of 10 CFR Part 50 Appendix J," and ANSI/American Nuclear Society (ANS) 56.8, "Containment System Leakage Testing Requirements."

The LRA states that, as part of the integrated leak rate test (ILRT) pretest requirements, a general inspection of the accessible interior and exterior surfaces of the containment SCs is performed for evidence of structural deterioration before initiating Type A testing. The LRA also states that these inspections are also performed during two other RFOs before the next Type A test, if the test interval has been extended to 10 years. The LRA further states that evidence of structural deterioration is corrected before the Type A test is performed.

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.S4.

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.S4 recommends the program to include all containment boundary pressure-retaining components. However, during its audit, the staff found that Callaway's FSAR-Standard Plant (SP) and ESP-SM-01001, "Containment Leakage Rate Testing Program," procedure indicated that a number of penetrations and containment isolation valves have been excluded from local leak rate tests (LLRTs) or Type B and C testing. Furthermore, the audited plant's operating experience database indicated that the applicant has substituted LLRTs in lieu of visual inspections (VT-2). It was not clear how the applicant proposed to manage the aging effects for any components not included in the 10 CFR Part 50, Appendix J, "scope of program," program element. By letter dated July 9, 2012, the staff issued RAI B2.1.29-1 and requested the applicant to identify how aging effects will be managed for those components (valves, penetrations, and other components) that have been excluded from the 10 CFR Part 50 Appendix J Program, during the period of extended operation. In addition, the staff requested the applicant to also indicate which AMPs will be used to manage the aging effects for each of the excluded components or to justify why an AMP is not necessary for the period of extended operation.

In its response dated August 9, 2012, the applicant stated that pressure-retaining components whose failure (loss of leak-tightness) could contribute to an increase in the overall integrated leakage rate of the containment system are subjected to Type A tests. The applicant stated that

containment penetrations that are provided with double seal closures and connections to allow for pressurization between the seals are subjected to Type B LLRTs. The applicant further stated that containment isolation valves are subjected to Type C LLRTs when they meet the following criteria:

(1) [t]he penetrating system provides a direct connection between the inside and outside atmospheres of the containment under normal operation

(2) [t]he system is isolated by containment isolation valves that close automatically to effect containment isolation in response to a [containment isolation] signal

(3) [t]he system is not an ESF system consisting of a closed piping system outside of the containment

The applicant also stated that FSAR-SP, Section 6.2.6.1.2, states that "[f]or penetrations that are exempt from Type B or C tests, the leakage testing requirement of Appendix J is accomplished by the Type A test." Accordingly, the applicant concluded that the scope of the 10 CFR Part 50, Appendix J Program includes all pressure-retaining components of the containment structure, and all of these components will be age-managed under this program during the period of extended operation.

The staff reviewed the applicant's response to RAI B2.1.29-1 and noted that the applicant's enumerated selectivity criteria for LLRTs for the containment isolation valves (Type C tests) are identical and therefore in accordance with FSAR-SP Section 6.2.6.3, "Containment Isolation Valve Leakage Rate Tests (Type C tests)." However, the staff noted that the response did not address age management of the exempted or excluded pressure boundary components. It was not clear in the response how the applicant through the infrequent leakage testing of the overall containment, associated with 10 CFR Part 50, Appendix J, Option B Type A test, could identify aging effects of the exempted or excluded pressure boundary components. The staff needed clarification on the applicant's approach and how it planned to manage aging effects of the exempted or excluded Type B and C tests of pressure boundary components from 10 CFR 50 Appendix J LLRTs. By letter dated October 11, 2012, the applicant supplemented the original response to RAI B2.1.29-1 where it specified how containment isolation valves excluded from Type C testing will be age managed during the period of extended operation. The applicant stated that these valves are included in Type A leakage testing and are to be managed by AMPs based on their materials and environments applicable to their respective systems (e.g., RHR, RCS, CTMT, boron and safety injection) as detailed in Table 1 of the supplemental response to RAI B2.1.29-1. The applicant also stated that all of these valves are constructed of stainless steel and are exposed to an external environment of either plant indoor air or borated water leakage, neither of which produces any aging effect for stainless steel. Therefore, the applicant concluded that no aging management is required for the external surfaces. For the internal environments, the applicant stated that the valves are managed by Water Chemistry Program (evaluated in SER Section 3.0.3.1.2) , One-Time Inspection Program (evaluated in SER Section 3.0.3.1.8), ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program (evaluated in SER Section 3.0.3.1.1), or Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program (evaluated in SER Section 3.0.3.2.12).

The staff reviewed the supplemental response provided on October 11, 2012, and found that it did not adequately address Type B testing. By letter dated November 20, 2012, the applicant supplemented its response to RAI B2.1.29-1. In the supplemental response, the applicant stated that Type B tests are performed on the following containment penetrations: personnel access hatches; equipment hatch; fuel transfer tube; electrical penetrations; penetration 34,

containment pressurization line; penetration 51, ILRT pressurization pressure sensing line; and penetrations 36, 50 and 68, maintenance spare air and electrical access penetrations. For penetrations other than those listed, the applicant stated that in addition to the ILRT, management of aging effects for all containment pressure-retaining components is performed by visual examination prior to ILRTs and at least once every 3 years. The applicant further stated that ASME Section XI, Subsection IWE Program performs a general visual examination of 100 percent of the accessible surfaces of the steel liner plate that includes penetrations, integral attachments, connection welds, and bolting and that any aging effects identified during these examinations will be managed in accordance with the applicant's ASME Section XI, Subsection IWE Program. The staff's evaluation of the ASME Section XI, Subsection IWE Program is documented in SER Section 3.0.3.2.15.

The staff reviewed the applicant's supplemental response and FSAR-SP Table 16.6-1, "Containment Isolation Valves," and verified that the valves excluded from LLRTs, as listed in Table 1 of RAI B2.1.29-1 response are subject to Type A testing. The staff also reviewed FSAR-SP Section 1.2.4, "Nuclear Steam Supply System," and verified that all of the nuclear steam supply system metal surfaces that are in contact with the reactor water, which include the excluded valves, are made of stainless steel and declared to be "corrosion-resistant" per FSAR-SP Section 3.1.6, "Fluid Systems." The staff noted that the aging effects for the excluded containment isolation valves are to be managed by other AMPs, the adequacy of which are evaluated in this SER as noted above.

For the containment penetrations excluded from LLRTs, the staff reviewed FSAR-SP Section 16.24, "Inservice Inspection," and confirmed that the containment pressure boundary inspections are done through procedure ESP-ZZ-01016, "ASME Section XI, IWE Containment Pressure Boundary Inspection." The staff audited the procedure and noted the comprehensive nature of the program regarding inspection of penetrations. The staff also noted that the program is not limited to evaluating the condition and performance of accessible penetrations but of inaccessible penetrations as well, acceptability of which rests on inspections and observations of relevant/nearby areas for prevalent conditions as indicators of degradation for the inaccessible areas/penetrations, in accordance with 10 CFR 50.55a(b)(2)(ix). The staff also noted that the procedure mandates inspection of 100 percent of the accessible containment pressure boundary areas to be performed at least triennially with increased frequency when deemed necessary. For any pressure boundary component not meeting the acceptance criteria, the procedure states that a corrective action report will be generated. Aging effects, during the period of extended operation, are to be managed per the applicant's ASME Section XI, Subsection IWE Program as noted above and evaluated in SER Section 3.0.3.2.15.

The staff finds the applicant's response acceptable, because it clarifies the scope of the program and explains how the applicant will manage the aging effects for penetrations and containment isolation valves that have been excluded from the 10 CFR Part 50 Appendix J Program Option B for Type B and C testing. The staff's concern described in RAI B2.1.29-1 is resolved. The staff determines that the "scope of the program" program element satisfies the criteria defined in the GALL Report and SRP-LR; therefore, the staff finds it acceptable.

Based on its audit of the applicant's 10 CFR Part 50 Appendix J Program and review of 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.S4.

Operating Experience. LRA Section B2.1.29 summarizes operating experience related to the 10 CFR Part 50, Appendix J Program. The LRA states that the 1999 ILRT showed that as-left leakage was 0.0577 weight percent per day (wt%/day), which is approximately 29 percent of the technical specification limit of 0.2 wt%/day. The LRA states that for Type B and C tests, the 2008 total maximum path leakage rate (MXPLR) was 107,308.6 standard cubic centimeters per minute (SCCM) or 43 percent of the technical specification limit of 252,028 SCCM. The LRA also states that the 2010 MXPLR was 79,208.5 SCCM, or approximately 31 percent of the technical specification limit. The existence of a significant margin between the technical specifications allowable limits and the as-tested values for the primary containment boundary indicates that the containment and its penetration, associated valves, and ancillary equipment are adequately maintained, and their aging effects are effectively managed.

The staff also audited Callaway's operating experience database and noted the containment hatch leak rate test was not satisfactory and failed the retest in 2004. Upon notification, the control room entered the appropriate TS and initiated an immediate action to evaluate the overall containment leakage rate, verify that the door is closed within 1 hour, and the affected air lock is operable within 24 hours. The root cause analysis, however, indicated that these leak rate test failures were not age-related but due to improper shaft seal alignment, incorrect reassembly sequencing, and bumping of the shafts because of equipment traffic through the hatch during unit outages.

The staff also confirmed that the applicant performed a review of NRC Generic Communications of industry operating experience and confirmed the applicability of the following INs:

- IN 85-08, "Industry Experience on Certain Materials Used in Safety-Related Equipment," for loss of sealing due to wear, damage, erosion, tear, surface cracks, and other defects
- IN 2004-09, "Corrosion of Steel Containment and Containment Liner," for loss of material due to erosion, general pitting, and crevice corrosion
- IN 2010-12, "Containment Liner Corrosion," for loss of material caused by corrosion

These INs apply to the plant's 10 CFR Part 50, Appendix J Program for management of the pertinent aging effects (loss or lack of sealing, corrosion, cracking, etc.).

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 that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.S4 was evaluated.

FSAR Supplement. LRA Section A1.29 provides the FSAR supplement for the 10 CFR Part 50, Appendix J Program. The staff reviewed this FSAR 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 FSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's 10 CFR Part 50, Appendix J 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 function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.14 Masonry Walls

Summary of Technical Information in the Application. LRA Section B2.1.30 describes the existing Masonry Wall Program as consistent with GALL Report AMP XI.S5, "Masonry Walls." The LRA states that the Masonry Wall Program addresses concrete masonry walls in proximity to safety-related systems. The LRA further states that the walls are monitored for cracking during structural inspections implemented as part of the Structures Monitoring Program.

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.S5.

For the "acceptance criteria" program element, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The "acceptance criteria" program element in GALL Report AMP XI.S5 recommends that further evaluation be conducted if the extent of cracking and loss of material is sufficient to impact the intended function of the wall or invalidate its evaluation basis. However, during its audit, the staff found that the applicant's Masonry Walls Program provided quantitative acceptance criteria, but no basis was provided for the acceptance criteria or how the criteria related to the recommended acceptance criteria in GALL Report AMP XI.S5. Therefore, by letter dated July 9, 2012, the staff issued RAI B2.1.30-1 requesting that the applicant provide the basis for the acceptance criteria and explain how the criteria meet the recommendations in program element six, "acceptance criteria," of the GALL Report AMP XI.S5.

In its response dated August 9, 2012, the applicant stated that the acceptance criteria described in the plant procedure are based on the criteria for concrete provided in ACI 349.3R, modified as necessary for masonry construction. The applicant further noted that procedures require an action request be written when other than very minor degradation is noted on the inspection report.

The staff reviewed the applicant's response and noted that plant procedures require an action request be created whenever greater than minor degradation is noted. This is similar to the guidance provided in program element six, "acceptance criteria," of the GALL Report AMP XI.S5, which recommends further evaluation if the extent of cracking and loss of material is sufficient to impact the intended function of the wall or invalidate its evaluation basis. The staff finds the applicant's response acceptable because it states that the acceptance criteria are based on an accepted reference (ACI 349.3R), and it further states that any degradation beyond minor is identified for further review, as recommended in the GALL Report. The staff's concern described in RAI B2.1.30-1 is resolved.

Based on its audit of the applicant's Masonry Walls Program and review of the applicant's response to RAI B2.1.30-1, 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.S5.

Operating Experience. LRA Section B2.1.30 summarizes operating experience related to the Masonry Walls Program. The LRA states that a review of structures monitoring reports from the last 10 years indicates that in-scope masonry walls are in good condition. Instances of cracking in masonry walls have been identified, but none have been severe enough to require corrective actions. These indications of degradation are identified and recorded for future trending purposes.

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 that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.S5 was evaluated.

FSAR Supplement. LRA Section A1.30 provides the FSAR supplement for the Masonry Walls Program. The staff reviewed this FSAR 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 maximum inspection interval of 5 years was not discussed in the summary description. The licensing basis for this program for the period of extended operation may not be adequate if the applicant does not incorporate this information into its FSAR supplement. By letter dated July 9, 2012, the staff issued RAI B2.1.31-1 requesting that the applicant include a discussion of the inspection interval in the FSAR supplement summary description.

In its response dated August 9, 2012, the applicant stated that masonry wall inspections are performed at intervals of no more than 5 years. The applicant also revised the FSAR supplement summary description to include the 5-year inspection interval.

The staff finds the applicant's response acceptable because the applicant updated the FSAR supplement description to include the necessary level of detail regarding the recommended 5-year inspection interval. Therefore, based on the applicant's response, the FSAR supplement for the Masonry Walls Program is an acceptable summary of the program and is consistent with the corresponding program description in SRP-LR Table 3.0-1. The staff's concern described in RAI B2.1.31-1 is resolved.

The staff finds that the information in the FSAR supplement, as amended by letter dated August 9, 2012, 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 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 function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.15 RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants

Summary of Technical Information in the Application. LRA Section B2.1.32 describes the existing RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program as consistent with GALL Report AMP XI.S7, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants." The LRA states that the AMP is implemented as part of the Structures Monitoring Program and manages the following aging effects:

- cracking; loss of bond; and loss of material (spalling, scaling)
- increase in porosity and permeability; loss of strength
- loss of material
- loss of material (spalling, scaling) and cracking
- loss of material; loss of form

The LRA also states that the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program proposes to manage structural steel and structural bolting associated with water-control structures. The LRA further states that Callaway performs algae treatment and riprap inspections along the ultimate heat sink (UHS) retention pond, and maintains benchmarks for monitoring settlement in any of the Category 1 structures, including the UHS cooling tower.

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.

Based on its audit of the applicant's RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants 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.S7.

Operating Experience. LRA Section B2.1.32 summarizes operating experience related to the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The LRA provides the following two examples as objective evidence that this AMP is capable of both monitoring and detecting the aging effects associated with the program:

- In 2005, water that entered open electrical boxes that were part of the abandoned lighting system, corroded the embedded conduits in the concrete wall, eventually causing spalling on the plant north face of the wall separating the 'A' and 'B' UHS fan deck rooms. The spalled area was patched with cement grout in 2006.
- Similar spalling was noted on the south wall in the 'D' UHS cooling tower due to rainwater seeping through an abandoned electrical conduit. To prevent recurrence,

before installing the grout patch, a hole was drilled to drain any water remaining in the abandoned conduits.

The LRA states that occurrences that would be identified under the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, will be evaluated to ensure there is no significant impact to safe operation of the plant and corrective actions will be taken to prevent recurrence.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant. 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 that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.S7 was evaluated.

FSAR Supplement. LRA Section A1.32 provides the FSAR supplement for the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The staff reviewed this FSAR 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 maximum inspection interval of 5 years was not discussed in the summary description. The licensing basis for this program for the period of extended operation may not be adequate if the applicant does not incorporate this information into its FSAR supplement. By letter dated July 9, 2012, the staff issued RAI B2.1.31-1 requesting that the applicant include a discussion of the inspection interval in the FSAR supplement summary description.

In its response dated August 9, 2012, the applicant stated that inspections of water-control structures are performed at intervals of no more than 5 years. The applicant also revised the FSAR supplement summary description to include the 5-year inspection interval.

The staff finds the applicant's response acceptable because the applicant updated the FSAR supplement description to include the necessary level of detail regarding the recommended 5-year inspection interval. Therefore, based on the applicant's response, the FSAR supplement for the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, is an acceptable summary of the program and is consistent with the corresponding program description in SRP-LR Table 3.0-1. The staff's concern described in RAI B2.1.31-1 is resolved.

The staff finds that the information in the FSAR supplement, as amended by letter dated August 9, 2012, 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 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 function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.16 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Summary of Technical Information in the Application. LRA Section B2.1.37 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." The LRA states that the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program manages increased resistance of connection to ensure that either aging of metallic cable connections does not occur and that the existing preventive maintenance program is effective such that a periodic inspection is not required. The LRA also states that the one-time test confirms the absence of age-related degradation of cable connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or 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.

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.E6.

For the "acceptance criteria" program element, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The "acceptance criteria" program element in GALL Report AMP XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," recommends that cable connections should not indicate abnormal temperature for the application when thermography is used. However, during its audit, the staff found that the applicant's plant aging management program evaluation report for the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program states that the acceptance criteria for thermography testing will be based on the temperature rise above the reference temperature. The reference temperature will be ambient temperature or the baseline temperature data from the same type of connections being tested.
The applicant referenced procedure EDP-ZZ-07001 Section 4.3.13. Section 4.3.13 of this procedure states that the acceptance criteria for the review of thermography result on the one-time inspection of cable connections will be based on the temperature rise above a reference temperature. The reference temperature will be ambient temperature or the baseline temperature data from the connections under test. The procedure does not specify the acceptance criteria for thermography inspections. The applicant stated that when the test acceptance criteria are not met, it will perform an evaluation that may include changes to the one-time inspection, increased inspection frequency, and replacement or repair of the affected connections. It is not clear to the staff that these statements are consistent because procedure EDP-ZZ-07001 Section 4.3.13 does not specify acceptance criterion for thermography inspections. By letter dated July 9, 2012, the staff issued RAI B2.1.37-1 requesting that the applicant describe the specific acceptance criteria for thermography or reference a plant-specific procedure that specifies the acceptance criteria for thermography inspection.

In its response dated August 9, 2012, the applicant stated that the first sentence in procedure EDP-ZZ-07001 markup, paragraph 4.1.11, has been revised to read: "A one-time inspection of a sample of cable connections shall be conducted using thermography per EDP-ZZ-01113." The applicant also stated that "EDP-ZZ-01113 specifies thermography inspection action levels for temperatures above a reference temperature. Element 6 AMP basis document B2.1.37 has been revised to identify the action levels section of EDP-ZZ-01113 for determining actions to be taken based on observed temperature rises recorded during the thermography inspection."

The staff finds the applicant's response acceptable because the applicant has revised procedure EDP-ZZ-01113 and basis document B2.1.37 to include thermography inspection action levels and actions to be taken for temperature rise measured above reference temperature during thermography inspections. The staff's concern described in RAI B2.1.37-1 is resolved.

Based on its audit and review of the applicant's response to RAI B2.1.37-1, the staff finds that program elements one through six for which the applicant claimed consistency with GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.E6.

Operating Experience. LRA Section B2.1.37 summarizes operating experience related to the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. LRA Section B2.1.37 summarizes the operating experience related to this AMP as follows:

> Callaway routinely performs infrared thermography on electrical components and connections. A review of plant operating experience identified scans where electrical cable connections showed thermal anomalies. The connections associated with these thermal anomalies were cleaned and re-tightened. No loss of equipment intended function has occurred because of these thermal anomalies.
>
> Operating experience with the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements [P]rogram has identified loose connections prior to loss of function. Occurrences that would be identified under the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements [P]rogram will be evaluated to ensure there is no significant impact to safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance for re-evaluation, repair, or replacement is provided for locations where aging is 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. 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 GALL Report AMP XI.E6 was evaluated.

FSAR Supplement. LRA Section A1.37 provides the FSAR supplement for the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. The staff reviewed this FSAR 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 six months before entering the period of extended operation for managing aging of applicable components.

The staff finds that the information in the FSAR supplement, as amended by letter dated February 28, 2013, 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 function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.17 Monitoring of Neutron-Absorbing Materials Other than Boraflex

Summary of Technical Information in the Application. LRA Section B2.1.38 describes the new Monitoring of Neutron-Absorbing Materials Other than Boraflex Program as consistent with GALL Report AMP XI.M40, "Monitoring of Neutron-Absorbing Materials Other than Boraflex." The LRA states that the Monitoring of Neutron-Absorbing Materials Other than Boraflex Program manages reduction of neutron-absorbing capacity, change in dimensions, and loss of material to ensure that aging of the Boral® neutron-absorbing material used in the spent fuel storage racks does not invalidate the criticality analysis of the spent fuel pool. The LRA states that the program is a monitoring program that performs inspections and in-situ testing of the Boral® panels in the spent fuel pool. The program testing includes areal density measurements of the boron-10 in the Boral® panels, and visual inspections of the Boral panel sheaths to look for geometry changes caused by bulging or swelling. The LRA also states that the results are evaluated against the acceptance criteria and previous inspections to determine whether corrective actions are required. The LRA further states that if corrective actions are required, appropriate actions are taken to ensure the required 5 percent subcriticality margin is maintained. In addition the LRA states that the Boral® panels in the spent fuel pool will be inspected on a 10-year frequency.

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.M40.

Based on its audit of the applicant's Monitoring of Neutron-Absorbing Materials Other than Boraflex 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.M40.

Operating Experience. LRA Section B2.1.38 summarizes operating experience related to the Monitoring of Neutron-Absorbing Materials Other than Boraflex Program. The LRA states that a search of Callaway historical information found no reduction of neutron-absorbing capacity, change in dimensions, and loss of material for Boral®. The LRA also states that occurrences that would be identified under the program will be evaluated to ensure that there is no significant impact to safe operation of the plant and corrective actions will be taken to prevent recurrence. The LRA further states that industry and plant-specific operating experience will be evaluated in the development and implementation of the 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. 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 GALL Report AMP XI.M40 was evaluated.

FSAR Supplement. LRA Section A1.38 provides the FSAR supplement for the Monitoring of Neutron-Absorbing Materials Other than Boraflex Program. The staff reviewed this FSAR 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. 29) to implement the new Monitoring of Neutron-Absorbing Materials Other than Boraflex Program six months before entering the period of extended operation for managing aging of applicable components.

The staff finds that the information in the FSAR supplement, as amended by letter dated February 28, 2013, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Monitoring of Neutron-Absorbing Materials Other than Boraflex 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 function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.18 Metal Enclosed Bus

Summary of Technical Information in the Application. LRA Section B2.1.39 describes the new Metal Enclosed Bus Program as consistent with GALL Report AMP XI.E4, "Metal Enclosed Bus." The LRA states that the Metal Enclosed Bus Program manages age-related degradation of in-scope non-segregated phase metal enclosed buses. The LRA also states that bus enclosure assemblies (internal and external), bus bar insulation, bus bar insulating supports, and bus bar bolted connections are included. The LRA further states that the metal enclosed buses within the scope of this program are the metal enclosed buses that provide power to the

service water pumps. In addition the LRA states that the service water pumps provide service water to fire protection hose stations in the ESW pump house through ESW piping.

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.

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.E4.

Operating Experience. LRA Section B2.1.39 summarizes operating experience related to the Metal Enclosed Bus Program. The LRA states that the Callaway CAP was searched to determine if metal enclosed bus failures have occurred. The LRA also states that Callaway's operating experience with the Metal Enclosed Bus Program has not identified any corrective actions related to the buses within the scope of license renewal. The LRA further states that "[o]ccurrences that would be identified under the Metal Enclosed Bus [P]rogram will be evaluated to ensure there is no significant impact to safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance for reevaluation, repair, or replacement is provided for locations where aging is found." In addition the LRA states that industry and plant-specific operating experience will be evaluated in the development and implementation of the 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. 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 GALL Report AMP XI.E4 was evaluated.

FSAR Supplement. LRA Section A1.39 provides the FSAR supplement for the Metal Enclosed Bus Program. The staff reviewed this FSAR 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. 30) to implement the new Metal Enclosed Bus Program six months before entering the period of extended operation for managing aging of applicable components.

The staff finds that the information in the FSAR supplement, as amended by letters dated April 25, 2012, and February 28, 2013, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Metal Enclosed Bus Program, the staff 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 function(s) will be maintained consistent with the CLB for the period of extended operation, as

required by 10 CFR 54.21(a)(3). The staff also reviewed the FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.19 Environmental Qualification (EQ) of Electric Components

Summary of Technical Information in the Application. LRA Section B3.2 describes the existing EQ of Electric Components Program as consistent with GALL Report AMP X.E1, "Environmental Qualification (EQ) of Electric Components." The applicant stated the Callaway EQ of Electric Components Program manages component thermal, radiation, and cyclical aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods.

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.

The staff reviewed the applicant's rockbestos cable EQ qualification. These cables use chemically cross-linked polyethylene cable, under the trade name "Firewall III," for use in nuclear applications. Institute of Electrical and Electronic Engineers (IEEE) Standard 383-1974, "Standard for Qualifying Class IE Equipment for Nuclear Power Generating Stations," identifies cable sizes that are considered representative of four different cable categories. The staff found that each of Callaway's test specimens is within the range of sizes considered by IEEE Standard 383-1974 and are representative of the respective cable types for a demonstration of qualification. The staff concluded that the test specimens are considered representative of the insulation types for the rockbestos "Firewall III" cables installed at Callaway.

In the thermal aging evaluation section PQE#E-057-00067P01, the applicant stated that cables are installed in various areas at Callaway and are subjected to a worst-case normal ambient temperature of 49 ^{o}C (120 ^{o}F) (represented by the containment operating floor/steam generator loop compartment), plus 10 ^{o}C (18 ^{o}F) for heat rise because of energization of the cable. The applicant also stated that cable specimens were thermally aged for 941 hours at 150 ^{o}C (302 ^{o}F), plus an additional 12 hours at 148 ^{o}C (298 ^{o}F). The applicant further stated that the additional 12 hours of aging time at 148 ^{o}C (298 ^{o}F) will be used to demonstrate margin and will not be used in the determination of qualified life. The applicant identified the chemically cross-linked polyethylene material as having an activation energy of 1.3412 eV. Using the thermal aging time and temperature listed above with an activation energy of 1.3412 eV and a total conductor temperature of 59 ^{o}C (138 ^{o}F), these cables are qualified for greater than 60 years at Callaway. In the applicant's analysis, significant margin exists since the cables remain qualified for 60 years as long as the insulation temperature is less than 87.9159 ^{o}C (190.23 ^{o}F).

By letter dated September 20, 2012, the applicant provided LRA Amendment 10 which included an exception to the "scope of program" program element by adding environmentally qualified mechanical components to the scope of the EQ of Electric Components Program. The staff reviewed the portions of the "scope of program" program element associated with an exception to determine if the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this exception follows.

Exception 1. LRA Section B3.2, as amended by letter dated September 20, 2012, states an exception to the "scope of program" program element. In this exception, the applicant stated that the EQ of Electric Components Program takes exception to the scope of program, which is limited in the GALL Report to electrical equipment to include the aging management of the

qualified life of safety-related mechanical components located in harsh environments. The staff reviewed this exception against the corresponding program element in GALL Report AMP X.E1 and finds it acceptable because a plant-specific TLAA for mechanical components qualified to Criterion 4 of Appendix A to 10 CFR Part 50 was established by the applicant in accordance with SRP-LR Sections 4.4.1 and 4.7. The inclusion of environmentally qualified mechanical components in LRA AMP B3.2 is acceptable in that LRA Table 3.6.2-1 identifies the same materials, environment, and aging effects requiring aging management for both electrical equipment environmentally qualified under 10 CFR 50.49 and the mechanical components qualified under Criterion 4 of Appendix A to 10 CFR Part 50.

Based on its audit of the applicant's EQ of Electric Components Program, and review of the applicant's response to RAI 4.4-1 provided in SER Section 4.4.2, 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 X.E1. The staff also reviewed the exception associated with the "scope of program" program element, and its justification, and it finds that the AMP, with the exception, is adequate to manage the applicable aging effects.

Operating Experience. LRA Section B3.2 summarizes operating experience related to the EQ of Electric Components Program.

In CAR No. 200904936, the applicant observed main steam isolation valve area temperature exceeded 49 °C (120 °F) (design) at least six times in a 2-year period. The applicant noted that the EQ impact was not evaluated and qualified life was not recalculated. The applicant stated that "[q]ualification reevaluation for components installed in the main steam isolation valve is required to ensure the degradation because of elevated temperature is accounted for, and the component is replaced, before expiring life." The applicant also stated that the EQ engineer determined that the brief temperature spikes did not impact qualified life.

The staff reviewed operating experience information in the application and during the audit to determine if the applicable aging effects, and industry and plant-specific operating experience, were reviewed by the applicant. As discussed in the audit report, the staff conducted an independent search of the plant operating experience information to determine if the applicant 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, resulting in the issuance of an RAI, as discussed below.

Although the staff identified two self-assessment reports, the staff did not identify any EQ of Electric Components Program health reports in its review of EQ operating experience. Multiple EQ health reports, issued periodically, can be used to identify adverse trends in EQ of Electric Components Program performance. In addition, CAR No. 201104724 identified plant program health report and program notebook as newly added requirements for the EQ of Electric Components Program. By letter dated August 23, 2012, the staff issued RAI B3.2-1 requesting the applicant to (a) provide the schedule for performing self assessment reports and EQ health reports consistent with LRA Section B3.2, and (b) provide additional operating experience (i.e., followup actions identified by the self-assessments (2004 and 2010), including corrective actions) that demonstrates the effectiveness of the EQ of Electric Components Program.

In its response, dated September 20, 2012, the applicant stated that the next self-assessment of the EQ of Electric Components Program is scheduled for 2014. The applicant also stated that, in accordance with plant procedures, self-assessments and benchmarks for the EQ of Electric Components Program are performed on an as-needed frequency, as agreed upon by the

supervisor and program owner. The applicant also stated that, in accordance with plant procedures, health reports are prepared for the EQ of Electric Components Program quarterly, with the third quarter report due October 2012.

In addition, the applicant provided a summary of self-assessments performed in 2004 and 2010, noting that bench strength was considered inadequate and that the EQ of Electric Components Program did not have provisions for a health report. To address the bench strength inadequacies noted in these self-assessments, the applicant stated that Callaway currently has six engineers qualified for the EQ of Electric Components Program, four of whom perform these responsibilities regularly. In addition, the applicant stated that corrective actions also were implemented that now provide for procedural requirements for the development of an EQ of Electric Components Program health report on a quarterly basis. The applicant also noted that the 2010 self-assessment identified only minor documentation issues already being resolved. The applicant further stated that the 2010 self-assessment did not identify any adverse conditions that resulted in premature aging. Additional program enhancements noted by the applicant included training for personnel interfacing with the EQ of Electric Components Program and first line supervisor training.

The staff finds the applicant's response acceptable because the applicant has established schedules for EQ of Electric Components Program health reports, self-assessments, and benchmarking. The applicant also provided additional operating experience, including corrective actions implemented to improve program effectiveness. The staff's concern described in RAI B3.2-1 is resolved.

Based on its audit and review of the application, and review of the applicant's response to RAI B.3.2-1, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP X.E1 was evaluated.

FSAR Supplement. LRA Section A2.2 provides the FSAR supplement for the EQ of Electric Components Program. The staff reviewed this FSAR 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 FSAR supplement, as amended by letter dated September 20, 2012, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's EQ of Electric Components Program, the staff concludes 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. 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 FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2 AMPs Consistent with the GALL Report with Exceptions or Enhancements

In LRA Appendix B, the applicant stated that the following AMPs are, or will be, consistent with the GALL Report, with exceptions or enhancements:

- boric acid corrosion
- bolting integrity
- open-cycle cooling water system
- closed treated water systems
- inspection of overhead heavy load and light load (related to refueling) handling systems
- fire protection
- fire water system
- aboveground metallic tanks
- fuel oil chemistry
- reactor vessel surveillance
- selective leaching
- inspection of internal surfaces in miscellaneous piping and ducting components
- lubricating oil analysis
- buried and underground piping and tanks
- ASME Section XI, Subsection IWE
- ASME Section XI, Subsection IWF
- structures monitoring
- protective coating monitoring and maintenance program
- insulation material for electrical cables and connections not subject to 10 cfr 50.49 environmental qualification requirements
- insulation material for electrical cables and connections not subject to 10 cfr 50.49 environmental qualification requirements used in instrumentation circuits
- inaccessible power cables not subject to 10 cfr 50.49 environmental qualification requirements
- fatigue monitoring
- concrete containment tendon prestress

For AMPs that the applicant claimed are consistent with the GALL Report, with exceptions or enhancements, the staff performed an audit to confirm that those attributes or features of the program for which the applicant claimed consistency with the GALL Report were indeed consistent. The staff also reviewed the exceptions and enhancements to the GALL Report to determine if they were acceptable and adequate. The results of the staff's audit and reviews are documented in the following sections.

3.0.3.2.1 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 enhancements, with GALL Report AMP XI.M10, "Boric Acid Corrosion." The LRA states that the Boric Acid Corrosion Program

addresses mechanical, electrical, and structural components exposed to borated water or reactor coolant leakage to manage loss of material and increased resistance of connection. The LRA also states that the Boric Acid Corrosion Program proposes to manage these aging effects through implementation of recommendations of NRC Generic Letter (GL) 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," and WCAP-15988-NP, "Generic Guidance for an Effective Boric Acid Inspection Program for Pressurized Water Reactors." The LRA further states that the Boric Acid Corrosion Program includes inspections, identification of leak paths, visual inspection of adjacent SCs, cleaning, evaluations, and tracking and trending of existing and repaired leaks.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.M10.

The staff also reviewed the portions of the "scope of program," "detection of aging effects," 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 B2.1.4 states an enhancement to the "scope of program" program element. In this enhancement, the applicant stated that procedures will be enhanced to include steel, copper alloy greater than 15 percent zinc, and aluminum as materials that are susceptible to boric acid corrosion. The "scope of program" program element of GALL Report AMP XI.M10 states that the program covers any structures or components on which boric acid corrosion may occur (e.g., steel, copper alloy greater than 15 percent zinc, and aluminum). By letter dated October 24, 2012, the applicant submitted LRA Amendment 13, removing enhancement 1 from the Boric Acid Corrosion Program. The applicant stated that it completed the enhancement to include steel, copper alloy greater than 15 percent zinc, and aluminum as materials that are susceptible to boric acid corrosion. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M10 and finds it acceptable because it makes the program consistent with the GALL Report recommendations by providing details in the inspection procedures to ensure that components constructed of materials susceptible to boric acid corrosion are appropriately addressed during inspections and engineering evaluations of borated water leakage.

Enhancement 2. LRA Section B2.1.4 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that procedures will be enhanced so that system engineers will inspect for signs of boric acid residue when performing system walkdowns. The "detection of aging effects" program element of GALL Report AMP XI.M10 states that the program includes interfaces with other site programs and activities, such that borated water leakage that is encountered by means other than the monitoring and trending activities of this program is evaluated and corrected. By letter dated October 24, 2012, the applicant submitted LRA Amendment 13, removing enhancement 2 from the Boric Acid Corrosion Program. The applicant stated that it completed the enhancement to revise procedures so that system engineers will inspect for signs of boric acid residue when performing system walkdowns. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M10 and finds it acceptable because it makes the program consistent with the GALL Report recommendations by providing for the discovery of borated water leakage and the associated followup evaluations through activities other than those established to specifically detect such leakage.

Enhancement 3. LRA Section B2.1.4 states an enhancement to the "corrective actions" program element. In this enhancement, the applicant stated that procedures will be enhanced to specify that the corrective actions taken by the program will include a consideration to modify the present design or operating procedures to mitigate or prevent recurrence of aging effects caused by borated water leakage. The applicant also stated that consideration will be given to modifications that (a) reduce the possibility of primary coolant leaks at locations where they may cause corrosion damage and (b) entail the use of corrosion resistant materials or the application of protective coatings or claddings. The "corrective actions" program element of GALL Report AMP XI.M10 states that corrective actions to prevent recurrences of degradation caused by borated water leakage should be included in the program. The GALL Report also states that these corrective actions include modifications to the present design or operating procedures that (a) reduce the probability of primary coolant leaks at locations where they may cause corrosion damage and (b) entail the use of corrosion resistant materials or the application of protective coating or claddings. By letter dated October 24, 2012, the applicant submitted LRA Amendment 13, removing enhancement 3 from the Boric Acid Corrosion Program. The applicant stated that it completed the enhancement to revise procedures to specify the corrective actions activities described above. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M10 and finds it acceptable because it makes the program consistent with the GALL Report recommendations by including the consideration of modifications to prevent recurrences of boric acid corrosion.

Based on its audit 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 enhancements associated with the "scope of program," "detection of aging effects," and "corrective actions" program elements and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.4 summarizes operating experience related to the Boric Acid Corrosion Program. The LRA states that stress-corrosion cracking was found in structural supports in the vicinity of a boric acid leak in the pressurizer spray line and was attributed, in part, to chlorides that likely originated during original construction. As a corrective action, the pressurizer cubical and the seal table were added to the quarterly walkdown of containment. The LRA also states that by the end of spring 2011, Callaway had an average age of open work orders on borated water leaks of approximately 10.5 months, down from approximately 25 months in 2008. The LRA further states that the program was revised between fall 2010 and spring 2011 to include (1) the addition of requirements to ensure boric acid evaluations were performed in a timely manner (with due dates for evaluation of susceptible materials); (2) increased training of plant personnel to identify leaks; and (3) guidance on the use of trending indicators, such as RCS leakage rate, containment cooling fouling, and containment air monitors.

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. The staff noted that the current effectiveness of the program is demonstrated by the significant downward trend in the average age of open work orders on borated water leaks, which coincided with the program revisions in 2010 and 2011 that strengthened training to identify leaks and the performance of timely evaluations of those leaks.

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 that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.M10 was evaluated.

FSAR Supplement. LRA Section A1.4 provides the FSAR supplement for the Boric Acid Corrosion Program. The staff reviewed this FSAR 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 completed Commitment No. 3 to implement the enhancements to the program before the period of extended operation.

The staff finds that the information in the FSAR supplement, as amended by letter dated October 24, 2012, 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 LRA Amendment 13, which revised the LRA to document that Commitment No. 3 was completed. 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 FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.2 Bolting Integrity

Summary of Technical Information in the Application. LRA Section B2.1.8 describes the existing Bolting Integrity Program as consistent, with enhancements, with GALL Report AMP XI.M18, "Bolting Integrity." The LRA states that the existing Bolting Integrity Program manages cracking, loss of material, and loss of preload for pressure retaining bolting. The program includes preload control, selection of bolting material, use of lubricants or sealants, and performance of periodic inspections for indication of aging effects. The LRA also states that the general practices established in this program are consistent with NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," EPRI-NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants" (with the exceptions noted in NUREG-1339 for safety-related bolting) and EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide," which are recommended by the GALL Report.

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 "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 “parameters monitored or inspected” program element of the GALL Report AMP XI.M18 recommends that the program monitor the effects of aging on the intended function of bolting and that components should be inspected for leakage, loss of material, cracking, and loss of preload. However, the staff noted that between 1985 and 1987, the applicant installed seal cap enclosures on four swing check valves to mitigate gasket leakage from the bolted body-to-bonnet flange joint. The use of seal cap enclosures as mitigation for leakage may prevent the bolting within the enclosure from being managed for loss of preload, cracking, and loss of material aging effects since the enclosure prevents direct inspection of the bolted joint. The known seal cap enclosures have since been removed; however, it is not clear to the staff whether additional seal cap enclosures have been installed or if seal cap enclosures are still used at the site to mitigate leakage. Furthermore, the staff requested clarification on how the use of seal cap enclosures is controlled such that aging effects can be managed in the period of extended operation. By letter dated July 5, 2012, the staff issued RAI B2.1.8-1 requesting that the applicant clarify whether seal cap enclosures are still in use at the plant and how aging effects will be managed if they are.

In its response dated August 6, 2012, the applicant stated that it had previously installed seal cap enclosures on two check valves in the normal charging line and two check valves in the alternate charging line at Callaway. The applicant stated that the seal cap enclosures were removed in 2002 and 2004, and no additional seal cap enclosures are currently installed at Callaway. The staff finds the applicant’s response acceptable because the applicant has confirmed that there are no additional seal cap enclosures at the site, and, therefore, aging management of bolting within seal cap enclosures will not be needed. Furthermore, the staff noted that NRC IN 2012-15, “Use of Seal Cap Enclosures to Mitigate Leakage from Joints that Use A-286 Bolts,” dated August 9, 2012, includes a detailed account of the four check valves described above and stated that all four valves were replaced or repaired to their original condition such that no aging effects resulting from the seal cap enclosures exists. The staff’s concern described in RAI B2.1.8-1 is resolved.

The “detection of aging effects” program element of the GALL Report AMP XI.M18 recommends periodic inspections of closure bolting for signs of leakage to ensure the detection of age-related degradation. However, GALL Report AMP XI.M18 does not include specific guidance for submerged bolting for which inspections for leakage are not practical. In a letter dated August 29, 2013, the applicant revised the LRA to include several new AMR items for pump closure bolting that is submerged in water or fuel oil, for which loss of material and loss of preload were identified as aging effects requiring management. Depending on the system in which the bolting resided, the applicant proposed to manage loss of material with the Open-Cycle Cooling Water System Program, Fuel Oil Chemistry Program, or the External Surfaces Monitoring of Mechanical Components Program. The applicant also proposed to manage loss of preload for all submerged bolting with the Bolting Integrity Program.

The staff noted that the applicant’s programs for managing aging of submerged bolting lacked information regarding how degradation will be detected, given the fact that the submerged environment limits accessibility and the ability to detect bolted joint leakage. By letter dated December 2, 2013, the staff issued RAI 3.3.2-2, requesting that the applicant state the parameters that will be inspected, whether inspections will or will not occur in the submerged environment, and the frequency of inspections.

In its response dated January 16, 2014, as revised by letter dated February 14, 2014 (which removed the submerged fire pumps from the scope of license renewal), the applicant revised the AMR items associated with submerged pump closure bolting to state that loss of material will be managed with the Bolting Integrity Program, rather than the programs initially identified.

The applicant described the program's aging management activities for loss of material as follows:

1. Essential service water (ESW) system:
    - The bolting will be visually inspected for degradation during dewatering of the essential service water intake bays, which is performed every four refueling outages (6 years).
    - The ESW pumps are tested quarterly and are repaired or refurbished when prompted by trending of pump parameters, such as pressure, flow, and vibration.
    - There have been no documented failures of the submerged ESW pump closure bolts in the last 10 years.

2. Service water system:
    - Each service water pump is replaced nominally every 6 years with a refurbished pump, and as a result, the pumps and associated bolting are not subject to aging management review.

3. Emergency diesel engine fuel oil storage and transfer system:
    - The fuel oil storage tanks (FOSTs) transfer pump closure bolting will be visually inspected for degradation when they are made accessible during the disassembly and inspection of the FOST transfer pumps, which is performed on a 10-year frequency.
    - The FOST transfer pumps are periodically tested and removed from service and repaired or refurbished when prompted by trending of pump parameters, such as pressure and flow.
    - There have been no documented failures of the submerged FOST transfer pump closure bolts in the last 10 years.

4. Oily waste system and floor and equipment drains system
    - The bolting associated with the submerged pumps will be visually inspected for degradation when they are made accessible during pump maintenance activities, but at least once every four refueling outages (6 years).
    - The waste water sumps are monitored during operator rounds to confirm that they are being drained, and the pumps are repaired or refurbished if the sumps are not being drained.
    - There have been no documented failures of the submerged waste water pump closure bolts in the last 10 years.

For all of the bolting subject to aging management review, the described visual inspections will be performed on a representative sample of bolting, defined as 20 percent of the population with a maximum of 25 and focusing on components most susceptible to aging. In addition, loss of preload for all of the bolting will be managed by (a) proper selection of bolting material, (b) the use of appropriate lubricants and sealants, (c) selection of bolting material with appropriate yield strength, and (d) proper torqueing of bolts, checking for uniform gasket compression, and application of appropriate preload.

The staff did not find the applicant's response acceptable because of the following concerns:

- The proposed inspections in the ESW, oily waste, and floor and equipment drains systems did not address the bolt threads, which likely are exposed to the most aggressive conditions due to their crevice-like nature.
- The response did not include the frequency at which the operator rounds occur to confirm that waste water sumps are being drained.
- It was unclear whether the procedures or logs for pump performance monitoring capture the basis for these aging management activities.
- It was not clear whether it was appropriate to remove the service water system pumps and associated bolting from the scope of license renewal, given the fact that these components could be reused.

By letter dated March 25, 2014, the staff issued RAI 3.3.2-2a requesting that the applicant address these concerns.

In its response dated April 23, 2014, as revised by letters dated May 6, 2014, and June 5, 2014, the applicant stated that, when the submerged raw water and waste water pump casings are disassembled during maintenance, the bolting threads will be inspected. The applicant also stated that the Operations Technician General Inspection Guide requires that inspections are conducted once every 12 hours to confirm that waste water sumps are operating as required. In addition, the applicant supported the removal of the service water pump bolting from the scope of license renewal by stating that, as part of the pump refurbishment, the bolting is replaced. The applicant also stated that the service water pump casing will be considered as long-lived and the effects of aging will be managed with the External Surfaces Monitoring Program.

The staff finds the applicant's responses to RAIs 3.3.2-2 and 3.3.2-2a and its proposal to manage the aging of submerged bolting acceptable because the submerged bolting in each of the systems will be addressed by multiple activities that, in combination, are capable of identifying degradation prior to loss of intended functions. These activities include (a) preventive measures (e.g., proper bolt torqueing and use of lubricants) to minimize the potential of loss of preload, (b) performance monitoring of the associated submerged pumps, and (c) periodic visual inspections of the bolt heads and opportunistic visual inspections of the bolt threads. The staff's concerns described in RAIs 3.3.2-2 and 3.3.2-2a are resolved. The staff's evaluations of the AMR items associated with these RAIs are documented separately in the appropriate SER sections.

The staff also reviewed the portions of the "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," 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 B2.1.8 states an enhancement to the "scope of program," "preventive actions," "detection of aging effects," and "corrective action" program elements.

In this enhancement, the applicant stated that its procedures will be enhanced to reference NUREG-1339 and EPRI NP-5769 to meet the GALL Report recommendations.

By letter dated April 25, 2012, the applicant submitted LRA Amendment 1 removing enhancement 1 from the Bolting Integrity Program, stating that it has been completed. The staff confirmed the completion during the audit and the review of these program elements is documented in the staff evaluation section above.

Enhancement 2. LRA Section B2.1.8 states an enhancement to the "scope of program," "parameters monitored or inspected," and "detection of aging effects" program elements. In this enhancement, the applicant stated that its procedures will be enhanced to include bolting in the list of items to be inspected during walkdowns. GALL Report AMP XI.M18 recommends that periodic system walkdowns be conducted to ensure detection of leakage at bolted joints before the leakage becomes excessive. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M18 and finds it acceptable because it makes the program consistent with the GALL Report recommendations.

By letter dated November 8, 2012, the applicant submitted LRA Amendment 15 removing enhancement 2 from the Bolting Integrity Program, stating that the procedures had been enhanced to include bolting in the list of items to be inspected during walkdowns.

Enhancement 3. LRA Section B2.1.8, as amended by letters dated January 16, 2014, and June 5, 2014, states an enhancement to the "scope of program" and "parameters monitored or inspected" program elements. In this enhancement, the applicant stated that procedures will be revised to include the periodic and opportunistic inspection activities for submerged bolting documented above in the discussion of RAIs 3.3.2-2 and 3.3.2-2a. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M18 and finds it acceptable because the combination of periodic inspections of bolt heads, opportunistic inspections of bolt threads, and the pump performance monitoring described in the documentation of the RAIs is capable of identifying bolting degradation prior to loss of intended functions.

Based on its audit of the applicant's Bolting Integrity Program and review of the applicant's response to RAIs B2.1.8-1, 3.3.2-2, and 3.3.2-2a, 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.M18.

Operating Experience. LRA Section B2.1.8 summarizes operating experience related to the Bolting Integrity Program. The LRA states that in a review of plant operating experience, issues were identified involving corrosion, missing or loose bolts, inadequate thread engagement, and improper bolt applications. The LRA further states that no generic bolting failure issues or trends have been identified, and there is no documented case of cracking of pressure containing bolting due to SCC.

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. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking corrective actions.

FSAR Supplement. LRA Section A1.8, as amended by letters dated April 25, 2012, November 8, 2012, January 16, 2014, May 6, 2014, and June 5, 2014, provides the FSAR supplement for the Bolting Integrity Program. The staff reviewed this FSAR 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 completed a portion of Commitment No. 5 to implement the first two enhancements to the program and committed to the implementation of the third enhancement no later than 6 months prior to the period of extended operation.

The staff finds that the information in the FSAR 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, 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. 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 function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.3 Open-Cycle Cooling Water System

Summary of Technical Information in the Application. LRA Section B2.1.10 describes the existing Open-Cycle Cooling Water System Program as consistent, with enhancements, with GALL Report AMP XI.M20, "Open-Cycle Cooling Water System." The LRA states that this program manages components exposed to raw water in the ESW system for loss of material, wall thinning, reduction of heat transfer, cracking, blistering, hardening, and loss of strength. The LRA also states that the activities for this program are consistent with Ameren Missouri's commitments for GL 89-13, "Service Water System Problems Affecting Safety-Related Components," and that these activities include component testing, visual inspections, nondestrucutive examinations, and biocide and chemical treatment, all of which ensure that aging effects are managed.

Based on reviews conducted by the staff, the staff identified an issue concerning loss of coating integrity of internal coatings of piping, piping components, heat exchangers, and tanks. The staff's position is documented in SER Section 3.0.3.4. By letters dated October 7, 2013, and March 25, 2014, the staff issued RAI 3.0.3-2 and RAI 3.0.3-2a, respectively, to address loss of coating integrity. By letters dated December 20, 2013, and April 23, 2014, the applicant responded to these RAIs by revising the Open-Cycle Cooling Water System program. The staff's evaluation of the applicant's response to RAI 3.0.3-2 and RAI 3.0.3-2a is documented in SER Section 3.0.3.4. The staff's evaluation of changes to LRA Sections B2.1.10 and A1.10, and Commitment No. 6 to address loss of coating integrity, follows.

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 "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. LRA Section B2.1.10 states that the activities for this program are consistent with the applicant's commitments to the requirements of GL 89-13. This is consistent with the "detection of aging effects" program element provided in GALL Report AMP XI.M20 regarding nondestructive examination methods. The applicant's response to GL 89-13 dated January 29, 1990, states that selected sections of ESW system piping are inspected each RFO for corrosion, erosion, and biofouling. The applicant's response also states that "each pipe is radiographed to determine any localized pitting. This is followed by ultrasonic testing using accurately placed grid locations to determine the extent of any damage." However, in its review of the applicant's implementing procedure, EDP-ZZ-01121, "Raw Water Systems Predictive Performance Program," the staff noted that the procedure neither discusses radiography as one of the nondestructive examination techniques used to inspect ESW piping nor includes a requirement that any pipe be radiographed each RFO to determine any localized pitting. In order to address this concern, by letter dated July 18, 2012, the staff issued RAI B2.1.10-1, requesting the applicant to demonstrate that the Open-Cycle Cooling Water System Program is consistent with its commitments to GL 89-13 regarding nondestructive examination techniques performed during each RFO.

In its response dated August 21, 2012, the applicant stated that it does not radiograph ESW piping as specified in its commitments for GL 89-13, but still meets the intent of its commitment by performing "scan inspections" using low-frequency electromagnetic technique (LFET) measurements. The applicant also stated that it performs ultrasonic thickness measurements to determine the extent of any degraded areas identified with LFET. The applicant further stated that it had entered its failure to update the original commitment to radiograph ESW piping into its CAP. In its review of the response, the staff noted that this electromagnetic test technique is described in NUREG/CR-6876, "Risk-Informed Assessment of Degraded Buried Piping Systems in Nuclear Power Plants," as being able to detect discontinuities and variations in materials. The staff finds the applicant's response acceptable because, although LFET by itself cannot be considered equivalent to radiography from a non-destructive examination perspective, it is capable of detecting loss of material, which can then be more accurately characterized using ultrasonic testing. The staff also finds that the use of LFET provides reasonable assurance that degraded ESW piping will be identified before there is a loss of intended function. Based on the above, the staff finds that the applicant is consistent with the intent of its commitments to GL 89-13 and that entering this issue into its CAP will address any concerns with the change to the original commitment. The staff's concern described in RAI B2.1.10-1 is resolved.

The "detection of aging effects" program element in SRP-LR Section A.1.2.3.4 states that, when sampling is used in condition monitoring programs, applicants should provide the basis for the inspection population and the sample size. The applicant's response to GL 89-13 states that selected sections of ESW piping are inspected each RFO for corrosion, erosion, and biofouling. During its review of the applicant's implementing procedure, EDP-ZZ-01121, the staff could not confirm the number of trended locations nor the criteria used to identify these locations. In addition, the implementing procedure contains a list of "non-trended inspected locations" that was not fully explained. In order to address this concern, by letter dated July 18, 2012, the staff issued RAI B2.1.10-2, requesting the applicant to provide details regarding the number and selection criteria for locations inspected and information regarding the selection criteria and purpose for inspecting non-trended locations.

In its response dated August 21, 2012, the applicant stated that the criteria used to select locations include: areas of stagnant or intermittent flow; pipe material, age, and configuration; previous inspection results; recent system challenges; chemistry trend data; industry operating experience; and system engineering recommendations. The applicant also stated that the number of locations varies from outage to outage based on the previously mentioned sample

criteria. Regarding the "non-trended inspected locations," the applicant stated that these are areas where it had previously performed permanent repairs and that it considers these locations for future monitoring.

In its review of the response, the staff finds the selection criteria for locations to be inspected each RFO to be acceptable because it includes parameters considered to be most significant with respect to the susceptibility to aging, including quantitative and qualitative considerations. However, the applicant did not provide the number of locations that it is trending. Based on information in response to RAI B2.1.10-6, also discussed in this section, the staff noted that the amount of piping currently inspected with LFET has decreased significantly since 2008. Because of this, the staff could not assess the process by which the applicant applied the selection criteria to identify specific locations for inspections. In order to address this concern, by letter dated October 24, 2012, the staff issued RAI B2.1.10-2a, requesting the applicant to discuss the apparent reduction in the amount of ESW piping inspected each outage since 2008 and to provide the current number of locations where localized damage is being monitored as specified in its GL 89-13 commitments.

In its response dated November 20, 2012, the applicant stated that it undertook a three-phase project beginning in 2007 to inspect the approximately 3800 feet of 6-inch diameter or greater above-ground carbon steel piping within the ESW system. The applicant stated that the first two phases inspected approximately 60 percent of the subject piping using LFET; due to the satisfactory results, it reduced the scope of the third phase to approximately 300 feet of piping in the 2008 RFO. The applicant also stated that, since completing the project, it has continued to inspect the ESW piping each RFO - approximately 310 feet in the 2010 RFO and 170 feet in the 2011 RFO - and plans to inspect 200 feet in the 2013 RFO. With regard to the number of locations where localized damage is being monitored, the applicant stated that it currently plans to monitor 11 locations for pitting in the 2013 RFO. The applicant also stated that this sample size is based on the inspection results and the extent of piping replacements being performed in the ESW system.

The staff finds the applicant's response acceptable because the extensive inspections of the past provide sufficient bases for the reduced scope of more recent inspections, and the current condition of the system and the process used by the applicant to select locations for monitoring provide reasonable assurance that pipe degradation will be detected before a loss of intended function. The staff's concerns described in RAIs B2.1.10-2 and B2.1.10-2a are resolved.

The "parameters monitored or inspected" program element in GALL Report AMP XI.M20 states that components with internal linings or coatings are periodically inspected and that the program ensures the detection of defective protective coatings that could adversely affect component performance. While LRA Section B2.1.10 states that Callaway uses internal coatings on heat exchanger components in various systems, it also states that the amount of coating surface is relatively small and that aging of the coating has not been a concern for ESW performance. Callaway's implementing procedure, ETP-ZZ-3001, "GL 89-13 Heat Exchanger Inspections," states that heat exchanger coatings are examined when they are accessible for inspections; however, Callaway's AMP evaluation report for open-cycle cooling water system, Section 3.3.2, states that heat exchanger inspections are performed for fouling, sediment, corrosion, erosion, and pitting, but does not state that coating degradation is included.

In addition, the applicant's letter dated July 16, 2007, which modified its commitments for GL 89-13, Item III.A, states that thermal performance testing will be the primary monitoring method for the component cooling water (CCW) heat exchangers, with cleaning and inspections

as necessary. The staff noted that, while the other heat exchangers with internal coatings will be periodically inspected, the inspections of the CCW heat exchanger are now based on need, as determined by thermal performance testing, which may not afford an opportunity to detect coating degradation prior to failure. In order to address these concerns, by letter dated July 18, 2012, the staff issued RAI B2.1.10-3, requesting the applicant to confirm that heat exchangers with applied coatings will be periodically inspected to detect coating degradation and to confirm the frequency of these inspections.

In its response dated August 21, 2012, the applicant stated that it uses internal coatings in the CCW heat exchangers, the control room air conditioners, and the Class 1E equipment air conditioner and that these components are inspected for signs of coating degradation at least every 5 years, as required by the heat exchanger inspection procedure. The applicant also stated that the ESW strainers, which are inspected every 6 years, have internal coatings and that the implementing procedure for the Open-Cycle Cooling Water System Program will be enhanced to specify inspection of these coatings. The applicant further stated that, since the total amount of internal coating is small and there has been no recent documented operating experience of internal coating failures, the frequency of inspections for the affected components provides reasonable assurance that the program will effectively identify coating failures and aging so that corrective actions can be initiated.

The staff finds a portion of the applicant's response acceptable because the implementing procedures will be enhanced to include the coatings for the ESW strainers resulting in the program's inclusion of all components with coatings whose failure could adversely affect downstream components. However, although the applicant did not identify any recent plant-specific operating experience in the LRA, the staff noted that the applicant had identified several issues with coating degradation between 2001 and 2007. The staff also noted recent industry operating experience that attributed the use of internal coatings beyond their established service life as a cause of coating failures in raw water systems, which then adversely affected downstream components. Since the program basis documents do not address coating service life, it was unclear to the staff how coatings will be managed and whether inspection techniques other than visual examinations would be used as a coating approaches its end of service life. It was also unclear to the staff whether the program includes qualification requirements for personnel who perform the coating inspections. In order to address this concern, by letter dated October 24, 2012, the staff issued RAI B2.1.10-3a, requesting the applicant to provide the service life for each of the coatings subject to aging management review used at Callaway, to provide program requirements as the coatings approach their end of service life, and to provide the qualification requirements for personnel performing coating inspections.

In its response dated November 20, 2012, the applicant stated that it does not rely on estimated service life to manage internal coatings and that intervals for monitoring the condition of the internal coatings begin immediately after the coatings are applied. The applicant also stated that it performs visual inspections as the primary method of monitoring the coating condition, and that corrective actions, extent of condition reviews, and evaluations for continued service are performed consistent with American Society for Testing and Materials (ASTM) D7167, "Standard Guide for Establishing Procedures to Monitor the Performance of Safety-Related Coating Service Level III Lining Systems in an Operating Nuclear Power Plant," which addresses performance of physical tests, such as dry film thickness or pull-off adhesion testing, at the discretion of the evaluator. The applicant further stated that coating inspections will be performed by a qualified nuclear coatings specialist as defined by ASTM D7108 or by coatings surveillance personnel under the technical direction of such a specialist.

The staff finds portions of the applicant's response acceptable, in that coating inspections will be performed by personnel either qualified as a nuclear coatings specialist or under the technical direction of such a specialist. However, in its review of other portions of the applicant's response, it was not clear to the staff that corrective actions, extent of condition reviews, and evaluations for continued service of coatings are being performed consistent with ASTM D7167 because Callaway's implementing procedures did not make this correlation and did not include the ASTM standard as a reference. In addition, Callaway's implementing procedures, EDP-ZZ-01112 and ETP-ZZ-03001, appear to focus on the potential corrosion effects from coating degradation, but they do not clearly address coating degradation as a source of macrofouling or provide guidance on the assessment of continued service for coatings. In order to resolve this concern, by letter dated February 21, 2013, the staff issued RAI B2.1.10-3b, requesting the applicant to provide additional justification for the frequency and type of inspections performed on coatings in ESW components whose degradation may adversely affect the safety function of downstream equipment.

In its response dated February 28, 2013, the applicant stated it will enhance the program's implementing procedures to specify that coating inspections will look for signs of coating detachment, such as flaking, peeling, and delamination. The applicant stated that the procedure enhancements will also include acceptance criteria that will not permit the above signs of detachment, but will allow blisters if they are intact and are completely surrounded by sound coating bonded to the surface. The applicant also stated that implementing procedures will be enhanced to require coating evaluation and testing whenever coating detachments are not repaired or removed. These enhancements will include confirmation that coating manufacturer installation requirements have been met, physical testing such as dry film thickness or adhesion testing as identified in ASTM-D7167 will be required, and coating detachments that are not repaired or removed to leave sound coating bonded to the surface will be trended. The applicant further stated that the program components are routinely inspected on a staggered outage basis between redundant trains, and there would be approximately 18 months between alternate train inspections and 36 months between specific component inspections. The applicant stated that the corresponding program components in the redundant trains have the same coatings, are exposed to the same environment, and are constructed of the same materials. In addition, the applicant stated that for the same components in redundant trains, the same material/environment conditions are being inspected every RFO.

The staff finds the applicant's response acceptable because the proposed changes to the implementing procedures will ensure that coating inspections will more rigorously look for coating degradation, and the acceptance criteria will ensure the coatings are bonded to the surface by including requirements for physical testing such as those identified in ASTM-D7167. In addition, the staff finds the inspection frequency of the coatings to be acceptable because the program's routine inspections for redundant trains will ensure comparable components in the same environment and constructed of the same material with the same coating will be inspected every RFO. The staff's concerns described in RAIs B2.1.10-3, B2.1.10-3a, and B2.1.10-3b are resolved.

The staff notes that the applicant's responses to RAI 3.0.3-2 and RAI 3.0.3-2a, dated December 20, 2013, and April 23, 2014, respectively, resulted in changes to the Open-Cycle Cooling Water System Program in regard to managing loss of coating integrity for the coatings addressed in RAIs B2.1.10-3, B2.1.10-3a, and B2.1.10-3b. As a result of these changes, the following statements made by the applicant in the response to RAIs B2.1.10-3, B2.1.10-3a, and B2.1.10-3b were altered:

- Inspection intervals have been modified to: (a) if no peeling, delamination, blisters, or rusting are observed, and any cracking or flaking has been found to be acceptable based on an evaluation by the coatings specialist, inspections will occur once every 6 years; (b) if no indications are found during the inspection of one train, the redundant train will not be inspected; (c) if the inspection results do not meet the conditions described in (a) and a coatings specialist determines that no remediation is required, inspections will occur every other refueling outage; and (d) repaired, replaced, or newly installed coatings will be inspected in each of the following two refueling outages. As further revised by letter dated June 5, 2014, the applicant restricted the redundant train inspection frequency to only apply if the components are not subject to turbulent flow conditions that could result in mechanical damage to the coating.

- The applicant removed ASTM D7167 as a reference to address performance of physical tests and instead stated that physical testing (i.e., destructive or nondestructive adhesion testing will be conducted in accordance with ASTM International Standards endorsed in RG 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Plants."

- The applicant removed ASTM D7108 as a reference for qualifying inspection personnel and instead stated that training and qualification of individuals involved in coating inspections are conducted in accordance with ASTM International Standards endorsed in RG 1.54 including guidance from the staff associated with a particular standard.

- The acceptance criteria was modified to allow indications such as cracking, flaking, and rusting if they are evaluated by a coatings specialist qualified in accordance with an ASTM International Standard endorsed in RG 1.54 including staff guidance associated with use of a particular standard.

- The requirement to confirm that coating manufacturer installation requirements have been met has been removed from the program.

The staff finds the applicant's changes to the Open-Cycle Cooling Water System Program associated with loss of coating integrity acceptable because they are consistent with staff recommendations for managing loss of coating integrity as documented in SER Section 3.0.3.4.

The "detection of aging effects" program element in GALL Report AMP XI.M20 states that inspection methods (e.g., visual or nondestructive examination) are in accordance with the applicant's docketed response to GL 89-13. The applicant's response to GL 89-13, dated January 29, 1990, Enclosure 2, Item III.B, states, in part, that air flow rates of all air-to-water heat exchangers are taken and trended and that visual inspections of the air side of the heat exchangers will be performed. The applicant modified its GL 89-13 commitment for heat exchanger testing in its letter dated July 16, 2007, and addressed Item III.A by changing the methodology to clean and inspect the water side of the tubes for all of the room coolers in lieu of efficiency testing. However, that letter did not address Item III.B regarding air flow rate monitoring and trending for room coolers. By contrast, for the containment air coolers, which are air-to-water heat exchangers, the 2007 letter states that the primary monitoring method will be cleaning and inspection of the inner tube walls and outer coil fins per EDP-ZZ-01112. In addition, although heat transfer is the intended function listed for heat exchangers exposed to ventilation atmosphere in various LRA Tables (e.g., 3.3.2-11, 3.3.2-13, 3.3.2-14, 3.3.2-15, and 3.3.2-19), reduction of heat transfer is not listed as an AERM for these GL 89-13 components. It was not clear to the staff that the program is being implemented consistent with the applicant

commitments regarding air-side heat exchanger inspections or that LRA tables containing these heat exchangers include AERM consistent with the activities described in the applicant commitments. In order to address these concerns, by letter dated July 18, 2012, the staff issued RAI B2.1.10-4, requesting the applicant to confirm that the Open-Cycle Cooling Water System Program is consistent with its commitments to GL 89-13 with respect to air-side heat exchanger inspections and, if needed, to update the appropriate tables in the LRA to reflect the aging effects being managed by this program through these commitments.

In its response dated August 21, 2012, the applicant stated that it regularly cleans and inspects the air-side of the GL 89-13 safety-related heat exchangers and that it no longer requires air-flow testing for the safety-related air-to-water heat exchangers, as documented in its commitment change for GL 89-13, dated July 16, 2007. The staff notes that the applicant's July 16, 2007, letter with commitment change for GL 89-19 states that the frequency of cleaning and inspection is based on past inspection results but will not exceed 5 years. The applicant also stated that, to demonstrate consistency with its GL 89-13 commitments, it will enhance the heat exchanger inspection procedure to visually inspect and, if necessary, clean the air sides of the GL 89-13 room coolers. In addition, the applicant revised LRA Tables 3.3.2-11, 3.3.2-13, 3.3.2-14, 3.3.2-15, and 3.3.2-19 to identify management of reduction of heat transfer for heat exchanger components that have a heat transfer intended function in a ventilation atmosphere.

The staff finds the response acceptable because the applicant confirmed that it conducts air-side inspections of applicable room coolers, consistent with its modified commitments to GL 89-13. The applicant also committed to enhance the implementing procedures to provide for this inspection activity and revised the applicable LRA tables to reflect the appropriate aging management activities being performed by this program. Based on the above discussion, the staff's concern described in RAI B2.1.10-4 is resolved.

The "acceptance criteria" program element in the GALL Report AMP XI.M20 states that inspected components should exhibit adequate design margin regarding design dimensions, such as minimum required wall thickness. SRP-LR Section A.1.2.3.6, "Acceptance Criteria," states that acceptance criteria should ensure that the component-intended function(s) are maintained consistent with all CLB design conditions during the period of extended operation. Callaway's AMP evaluation report for this program, Section 3.6.2, states that minimum wall thickness acceptance criteria are listed in procedure EDP-ZZ-1121, Attachments 3 and 4. In its review of operating experience reports, the staff noted in CAR 200703680 that a flange for an ESW valve had corrosion damage. The CAR states that more than 50 percent of the gasket seating area was damaged by corrosion, but it does not provide any information regarding the depth of the corrosion. The CAR's corrective actions section states, "[t]he extent of the corrosion damage identified does not adversely impact the structural integrity of the flange. The standard Class 3 manufacturing tolerance of 12.5 percent thickness provides assurance that this condition is not a structural or pressure boundary issue."

The staff noted that the acceptance criteria listed in procedure EDP-ZZ-1121, Attachments 3 and 4, only apply to pipe minimum wall thickness and do not address flange thicknesses. The staff also noted that the 12.5 percent manufacturing tolerance stated in the CAR only applies to pipe wall thickness; the tolerance for flange thickness is typically specified in ANSI B16.5, "Pipe Flanges and Flanged Fittings," with a 0.0 "minus" value. ANSI B16.5 does not appear to give a "plus or minus" 12.5 percent tolerance for flange thickness, and without knowing the depth of the corrosion and the thickness of the flange, the structural integrity of the flange during the period of extended operation has not been demonstrated. By letter dated July 18, 2012, the staff issued RAI B2.1.10-5, requesting the applicant to address structural integrity evaluations

where flange thicknesses have been adversely affected, and to provide the acceptance criteria that will be used to ensure that the component-intended function(s) will be maintained consistent with all CLB design conditions, or provide the basis for applying the “standard Class 3 manufacturing tolerance of 12.5 percent” to flange thicknesses.

In its response dated August 21, 2012, the applicant stated that the pipe spool piece in question has been replaced with stainless steel; therefore, the current configuration maintains the structural integrity of the system. The applicant also stated that, although the 12.5 percent used in the response to CAR 200703680 does not apply to flange thickness, the degradation on the flange face was fairly shallow such that structural integrity was not adversely impacted to the point of flange failure. The response discussed the quality control acceptance criteria for the percentage of defective gasket seating area, which states, “[n]o transverse discontinuities longer than 50 [percent] of gasket seat area width (25 [percent] for serrated finish surface)," and stated that any defect exceeding these criteria would go to the engineering department for evaluation.

In its review of the response, the staff noted that the applicant’s criteria for addressing flange degradation pertained to the surface area, which would affect leakage, but the criteria did not provide any guidance regarding the loss of flange thickness, which would affect structural integrity. In addition, the staff noted that CAR 200703680 addressed a condition requiring an engineering evaluation, and the engineering evaluation apparently justified the structural integrity of the flange based on incorrect tolerances. It was unclear to the staff what acceptance criteria will be used where flange thicknesses have been adversely affected and what assurances that the 12.5 percent pipe wall thickness manufacturing tolerance will only be applied to appropriate components in engineering evaluations of structural integrity. Therefore, by letter dated October 24, 2012, the staff issued RAI B2.1.10-5a, requesting the applicant to provide the acceptance criteria for flange thickness degradation that will be used to ensure the component’s intended function(s) will be maintained consistent with all CLB design conditions and to provide assurance that the 12.5 percent pipe wall thickness manufacturing tolerance will only be applied to appropriate components in engineering evaluations of structural integrity.

In its response dated November 20, 2012, the applicant stated that it is not its practice to evaluate the acceptance of degraded flanges based on manufacturer’s tolerances and noted that the evaluation cited in CAR 200703680 compared the observed flange corrosion to the 12.5 percent pipe tolerance as a reasonable qualitative conclusion that structural integrity was not challenged. The applicant explained that the CAR was generated because the corrosion observed on the surface of the flange exceeded the quality control acceptance criterion of 50 percent surface degradation measured transversely. The applicant stated that corrective action was taken to apply a coating, which is appropriate for surface degradation, but subsequently, the affected piping was replaced with stainless steel. The applicant also stated that it had searched Callaway operating experience and did not identify any instances where flange degradation challenged structural integrity.

The staff finds the applicant’s response acceptable. GALL Report XI.M20 recommends that the acceptance criteria be in accordance with the applicant’s docketed response to NRC GL 89-13. The applicant’s GL 89-13 program includes use of the Callaway Operational Quality Control Manual, which contains acceptance criteria for flange degradation. Since no other flange degradation structural issues were found, the applicant has provided reasonable assurance that it would identify structural degradation of flanges prior to loss of intended function. The staff’s concerns described in RAI B2.1.10-5 and B2.1.10-5a are resolved.

The staff also reviewed the portions of the "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements associated with the enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B2.1.10 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements. In this enhancement, the applicant stated that procedures will be enhanced to include polymeric material inspection requirements and acceptance criteria to be consistent with examinations described in the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The staff noted that GALL Report AMP XI.M20 recommends that examinations of polymeric materials be consistent with those described in GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components." GALL Report AMP XI.M38 recommends that visual and tactile inspections be conducted whenever the component surface is accessible. The staff also noted that the polymer examinations in the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program are consistent with GALL Report AMP XI.M38, as documented in SER Section 3.0.3.2.12. 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 inspections of polymeric components within the program will be consistent with those described in GALL AMP XI.M38, as specified in the "detection of aging effects" program element in GALL AMP XI.M20 and will be able to detect aging effects before there is a loss of intended function.

Enhancement 2. In response to RAI B2.1.10-3, the applicant committed to enhance the "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements by revising procedures to inspect the coatings in the ESW strainers for degradation once every 6 years. As amended by letter dated December 20, 2013, this enhancement was deleted, and by letter dated April 23, 2014, a new enhancement (Enhancement No. 5) was proposed to address loss of coating integrity.

Enhancement 3. In response to RAI B2.1.10-4, the applicant committed to enhance the "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements by revising procedures to inspect and clean, if necessary, the air-side of the safety-related air-to-water heat exchangers cooled by ESW. The staff notes that the current frequency for cleaning and inspection of safety-related heat exchangers, as provided in the applicant's commitment change for GL 89-13 dated July 16, 2007, is based on past inspection results, but will not exceed 5 years. 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 revised procedures will manage reduction of heat transfer due to fouling of the air side for heat exchangers consistent with the applicant's commitments to GL 89-13.

Enhancement 4. In response to RAI B2.1.10-3b, the applicant committed to enhance the "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements by revising inspection procedures of internal coatings to specify acceptance criteria for, and to identify indications of, coating detachment that could affect downstream components. As amended by letter dated December 20, 2013, this enhancement was deleted, and by letter dated April 23, 2014, a new enhancement (Enhancement No. 5) was proposed to address loss of coating integrity.

Enhancement 5. As amended by letters dated December 20, 2013, April 23, 2014, and June 5, 2014, LRA Section B2.1.10 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements. In this enhancement, the applicant provided a list of procedure enhancements associated with coatings inspections (e.g., base line inspections, extent of inspections), training and qualification of individuals involved in coating inspections, acceptance criteria, and corrective actions. These enhancements and the corresponding staff evaluation are documented in the response to RAI 3.0.3-2a Request Nos. (2), (5), and (6) in SER Section 3.0.3.4.

Enhancement 6. As amended by letter dated December 20, 2013, LRA Section B2.1.10 adds an enhancement to the "detection of aging effects" program element. Prior to the period of extended operation, the applicant will select an inspection technique from available techniques to identify internal pipe wall degradation due to MIC for performance of a one-time inspection of a buried carbon steel piping segment that is representative of other accessible carbon steel ESW piping segments. This enhancement is acceptable because, as part of the activities to address recurring internal corrosion, it will provide an assessment of the buried carbon steel piping to ensure that the condition of accessible piping is representative of buried piping.

Based on its audit and review of the applicant's responses to RAIs B2.1.10-1, B2.1.10-2, B2.1.10-2a, B2.1.10-3, B2.1.10-3a, B2.1.10-3b, B2.1.10-4, B2.1.10-5 and B2.1.10-5a, 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. Based on its review of the applicant's responses to RAIs 3.0.3-2 and 3.0.3-2a, the staff also finds that the applicant's program changes to address loss of coating integrity are consistent with staff recommendations for managing loss of coating integrity documented in SER Section 3.0.3.4. In addition, the staff reviewed the enhancements associated with the "preventive actions," "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 B2.1.10 summarizes operating experience related to the Open-Cycle Cooling Water System Program. The applicant stated that the design of the containment cooler coils did not allow them to be mechanically cleaned and that the coil performance degraded over time due to debris from the service water system. The applicant replaced the coils for the four containment coolers in 2001 and 2002 with a design that included removable cover plates, which permit access to mechanically clean individual tubes. The applicant also discussed the replacements in 2009 and 2010 of several safety-related room coolers and the heat exchangers for the emergency diesel generator (EDG) jacket water, lube oil, and intercoolers with coils and tubes made from AL6XN stainless steel. These replacements were due to performance and aging issues, including loss of material. In 2008 and 2009, the applicant also replaced the buried portions of the ESW supply from the ESW pump house and the return to the ultimate heat sink cooling tower with high-density polyethylene (HDPE) piping due to the material condition of the ESW system. The applicant stated that these examples show that the existing Open-Cycle Cooling Water System Program activities prevent or detect aging effects and that the continued implementation of the program will effectively identify aging prior to 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 its review of plant-specific operating experience, the staff noted the discussion in CAR 200608086 regarding wall thinning of carbon steel components, which adversely affected the ability of the ESW system to perform its intended function. In addition, the staff noted that a number of carbon steel components are still in service and that the applicant did not discuss plans for future replacement with corrosion-resistant materials. Based on the past extent of degradation in the ESW, the staff lacked sufficient information to conclude that the Open-Cycle Cooling Water System Program will adequately manage the effects of aging so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation. By letter dated July 18, 2012, the staff issued RAI B2.1.10-6, requesting the applicant to provide (a) corrective actions taken and enhancements made to prevent recurrence of the pervasive degradation in the system, (b) a summary of the augmented inspections that are currently being performed to identify loss of material before through-wall leaks occur, and (c) a summary of past analyses conducted that evaluated the structural integrity of degraded areas, including data to demonstrate that the degradation is limited to independent, localized corrosion sites.

In its response dated August 21, 2012, the applicant discussed the 2005 event in which it declared the ESW B train inoperable due to under-deposit corrosion in a section of the pipe between the pump strainer and pump discharge valve. The applicant stated that its extent of condition review, which included volumetric examinations of corresponding segments in the A train and additional locations of horizontal pipe exposed to intermittent flow, did not identify any additional degradation. Based on these inspections, the applicant concluded that the initiating cause was unique to the location where the corrosion occurred and that no further corrective actions or program enhancements were needed beyond the replacement of the degraded pipe section.

The applicant also stated it has replaced a substantial amount of ESW piping including (a) all small bore carbon steel ESW piping (approximately 3400 feet) with stainless steel pipe starting in the mid-1990s; (b) 79 feet of 30-inch piping, several sections of 8-inch and 6-inch piping, the pump discharge spool and reducer, and the pump discharge cross-connect spool piece in 2007; and (c) the buried portions of the ESW supply and return lines with HDPE from 2008 to 2009. The applicant stated it did not have any plans for additional replacements. In addition, the applicant stated it used LFET to inspect approximately 2000 feet of ESW piping in spring 2008, 300 feet in each of the refueling outages in fall 2008, spring 2010, and fall 2011, and it planned to inspect 200 feet in spring 2013. The applicant also described the five engineering evaluations it performed in 2007, the two in 2008 and one in 2009 for the structural integrity of the ESW system due to leakage or minimum wall thickness deficiencies.

The staff finds the above portions of the applicant's response acceptable because the applicant has replaced a significant amount of carbon steel ESW piping with material that is much more resistant to degradation from raw water. In addition, the applicant has performed a significant number of inspections using the LFET. The staff notes that the number of degraded locations needing evaluation has decreased since 2007 and that no additional evaluations have apparently been required since 2009. Based on the above discussion, the staff finds that the applicant has taken corrective actions to address the consequences of past program

weaknesses. The staff's concerns described in RAI B2.1.10-6 are resolved except as noted below.

As part of it review of past operating experience, the staff noted the discussion in CAR 200703627 that correlates the identification of ESW system leaks with periodic testing for the engineered safety feature actuation system (ESFAS). This testing includes actuations in response to loss of offsite power. The CAR states that ESW components above a certain elevation will naturally drain when the pump is secured in the ESFAS procedure and that corrective actions taken to date have not been effective in preventing ESW system hydraulic transients during this testing. As part of RAI B2.1.10-6, the staff questioned whether the applicant included these hydraulic transient loads in its structural integrity evaluations of degraded ESW piping. In its response dated August 21, 2012, the applicant stated that calculations of minimum wall thickness do not require consideration of transient pressure caused by a water hammer event and that the Callaway pipe design standard establishes how design pressures are defined and allows pressure excursions in excess of design for short periods of time.

In its review of this portion of the RAI response, the staff noted that the ASME Code requires the system design pressure to include allowances for pressure surges and that, although Callaway's pipe design standard allows pressure excursions in excess of design, the ASME Code limits the stresses resulting from pressure excursions depending on the service level. In order to address this issue, by letter dated October 24, 2012, the staff issued RAI B2.1.10-6a, requesting the applicant to address why the exclusion of pressure surges caused by transient loads and loss of offsite power in structural evaluations meets the CLB.

In its response dated November 20, 2012, the applicant stated that in the 1990s, when it was recognized that procedural guidance would not prevent water hammer from occurring during a loss of offsite power event, pipe stress evaluations were performed to include water hammer as an upset design condition, and the structural interactions of the event were accounted for by factoring pipe stress results in the code equations to determine the minimum wall thickness. In addition, the applicant stated that it installed multiple modifications to address the susceptibility of the ESW system to water hammer, most recently including a 30-inch check valve to prevent draining and re-sequencing two isolation valves as discretionary enhancements to bolster the system's defense in depth against potential water hammer occurrences. The applicant also stated that, since these changes were implemented, there have been no recurrences of water hammer in conjunction with ESFAS testing. The staff finds the applicant's response acceptable because the minimum pipe wall thickness had previously considered the structural interactions due to water hammer, which meets the CLB for structural evaluations. The staff also noted that the discretionary enhancements to the ESW system have prevented recurrence of the water hammer. Based on the above, the staff's concerns described in RAIs B2.1.10-6 and B2.1.10-6a are resolved.

Based on its audit and review of the application and review of the applicant's response to RAI B2.1.10-6 and B2.1.10-6a, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.M20 was evaluated.

FSAR Supplement. LRA Section A1.10 provides the FSAR supplement for the Open-Cycle Cooling Water System Program. The staff reviewed this FSAR 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 Open-Cycle Cooling Water System Program procedures six months before the period of extended operation to include (a) polymeric material inspection requirements, parameters monitored and acceptance criteria; (b) inspection of the internal coatings in the ESW strainers; (c) inspection and cleaning of the air side of ESW-cooled heat exchangers, and (d) trending, acceptance criteria, and testing for indications of coating detachment to confirm coating is bonded to surface.

The staff noted that the applicant modified LRA Section A.1.10 in response to RAI 3.0.3-2 and RAI 3.0.3-2a by letters dated December 20, 2013, and April 23, 2014, to address loss of coating integrity. The staff also noted that the applicant committed (in Commitment No. 6) to revise the Open-Cycle Cooling Water System Program procedures to address loss of coating integrity as described above in Enhancement No. 5.

The staff finds that the information in the FSAR supplement, as amended by letters dated February 28, 2013, December 20, 2013, and April 23, 2014, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Open-Cycle Cooling Water System Program, the staff determines that those 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. Also, the staff reviewed the enhancements and confirmed that their implementation through Commitment No. 6 six months before the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff also reviewed the FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.4 Closed Treated Water Systems

Summary of Technical Information in the Application. LRA Section B2.1.11 describes the existing Closed Treated Water Systems Program as consistent, with an enhancement, with GALL Report AMP XI.M21A, "Closed Treated Water Systems." The LRA states that the Closed Treated Water Systems Program addresses components in closed-cycle cooling water systems to manage the effects of loss of material, cracking, and reduction of heat transfer. The LRA also states that the AMP proposes to manage these aging effects through periodic visual inspections and control of water chemistry consistent with the guidelines of EPRI 1007820, "Closed Cooling Water Chemistry Guideline."

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.M21A.

For the program description, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

During its audit, the staff found inconsistencies in the LRA AMP description, program basis document, and implementing procedures regarding which water chemistry control approach is used in the boron thermal regeneration (BTR) system chilled water system. The staff noted that the improper identification of the water chemistry may lead to an inadequate sampling of inspection populations based on water treatment programs.

By letter dated July 5, 2012, the staff issued RAI B2.1.11-1 requesting that the applicant state the water chemistry environment of the BTR system chilled water system and revise the LRA, program basis document as well as the implementing procedures accordingly.

In its response dated August 6, 2012, the applicant stated that the water chemistry treatment program for the BTR system chilled water system is nitrite/molybdate with tolyltriazole. The applicant revised LRA Section B2.1.11 and stated that it revised the program basis document and inspection procedure to indicate this environment. The applicant also revised AMR items in LRA Table 3.3.2-10 to show that components in the BTR system chilled water system are exposed internally to closed-cycle cooling water and are managed with the Closed Treated Water Systems Program, rather than being exposed to demineralized water and managed with the Water Chemistry and One-Time Inspection programs, as originally stated in the LRA.

The staff finds the applicant's response acceptable because the correct identification of the water chemistry treatment program in the BTR system chilled water system in the LRA, program basis document, and inspection procedure ensures that proper inspection sampling of components exposed to each water treatment program can be performed. The staff's review of the revised AMR items associated with the BTR system chilled water system is documented in SER Section 3.3.2.1. The staff's concern described in RAI B2.1.11-1 is resolved.

The staff also reviewed the portions of the "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements associated with 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 B2.1.11 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements. In this enhancement, the applicant stated that procedures will be enhanced to include visual inspections of the surfaces of components with closed treated water environments. The applicant also stated that representative samples of each combination of material and water treatment program will be inspected opportunistically, or at least every 10 years, for cracking, loss of material, and fouling. However, during its audit of the Closed Treated Water Systems Program, the staff noted that the program basis document and implementing procedures differ with this inspection sampling methodology. The staff also noted that neither the LRA nor the program basis document state that inspection locations will be selected based on likelihood of corrosion or cracking, as recommended by GALL Report AMP XI.M21A. By letter dated July 5, 2012, the staff issued RAI B2.1.11-2 requesting that the applicant state what inspection sampling methodology will be used and whether inspection locations will be selected based on likelihood of corrosion or cracking or to provide technical justification for not doing so.

In its response dated August 6, 2012, the applicant stated that the correct sampling methodology is defined in the program basis document and consists of a sample size of 20 percent of components, up to a maximum of 25 components, for each chemical environment, with at least two samples of each material to be included in the sample for each environment. The applicant also stated that the inspections will be conducted during each 10-year period beginning 10 years before entry into the period of extended operation. The applicant further stated that the draft implementing procedure will be corrected to agree with the program basis document. In addition, the applicant revised the LRA and Commitment No. 7 to state that inspection locations will be selected based on likelihood of corrosion and cracking.

The staff finds the applicant's response acceptable because the sampling methodology described in the RAI response provides sufficient opportunity to discover the presence or extent of aging for each type of material in every applicable environment before loss of component-intended functions. The staff noted that the application of this sampling methodology at least every 10 years, beginning 10 years before the period of extended operation, allows the progression of degradation to be adequately monitored and trended. The staff's concern described in RAI B2.1.11-2 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 verify the effectiveness of water chemistry controls, as described above.

Based on its audit of the applicant's Closed Treated Water Systems Program and review of the applicant's responses to RAIs B2.1.11-1 and B2.1.11-2, 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.M21A. In addition, the staff reviewed the enhancement associated with the "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements and finds that when implemented it will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.11 summarizes operating experience related to the Closed Treated Water Systems Program. The LRA states that a review of the past 10 years of operating experience did not identify any instances where aging effects arising from closed-cycle cooling water led to loss of intended function of any of the heat exchangers served by the systems within the scope of this program. The LRA also states that cracking due to SCC was identified in the outlet nozzle area of the letdown heat exchanger during a 2002 inspection that was prompted by similar cracking at Wolf Creek. The affected components were replaced and followup inspections did not find any additional cracking.

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 that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.M21A was evaluated.

FSAR Supplement. LRA Section A1.11 provides the FSAR supplement for the Closed Treated Water Systems Program. The staff reviewed this FSAR 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. 7) to enhance the program six months before the period of extended operation to include visual inspections for loss of material, cracking, and fouling at least once every 10 years as described in the enhancement description above.

The staff finds that the information in the FSAR supplement, as amended by letter dated February 28, 2013, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Closed Treated Water 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. 7 six months before 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 FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

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

Summary of Technical Information in the Application. LRA Section B2.1.12 describes the existing Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program as consistent, with enhancements, with GALL Report AMP XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems." The LRA states that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program manages loss of material and loss of preload for bolting for all crane, trolley, and hoist structural components; and fuel handling equipment and applicable rails within the scope of license renewal. The LRA also states that visual inspections will manage loss of material due to corrosion of structural members and bolting, loss of material due to wear of rails, and loss of preload for bolted connections. The LRA further states that crane inspections are performed in accordance with the ASME B30 standards, which are recommended by the GALL Report.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.M23. The staff also reviewed the portions of the "parameters monitored or inspected," "detection of aging effects," "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 B2.1.12 states an enhancement to the "parameters monitored or inspected," and "detection of aging effects" program elements. In this enhancement, the applicant stated that its procedures will be enhanced to inspect crane structural members for loss of material due to corrosion and rail wear and loss of preload due to loose or missing bolts and nuts. GALL Report AMP XI.M23 recommends that visual inspections be conducted to ensure that there is no loss of material occurring and that bolted connections are monitored for loose bolts, missing or loose nuts, and other conditions indicative of loss of preload. 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 ensure inspections of crane structural members for loss of material because of corrosion and rail wear and loss of preload caused by loose or missing bolts and nuts are performed consistent with the recommendations in the GALL Report.

Enhancement 2. LRA Section B2.1.12 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that the program will be enhanced to include performance of periodic inspections as defined in the appropriate ASME B30 series standard for all cranes, hoists, and equipment handling systems within the scope of license renewal and that for handling systems that are infrequently in service, such as those only used during RFOs, periodic inspections may be deferred until just before use. GALL Report AMP XI.M23 recommends that visual inspections be conducted at a frequency in accordance with the appropriate ASME B30 series standard and that infrequently used systems be inspected just before use. 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 ensure that the periodic inspections will be performed consistent with the recommendations in the GALL Report.

Enhancement 3. LRA Section B2.1.12 states an enhancement to the "acceptance criteria" program element. In this enhancement, the applicant stated that the program will be enhanced to require evaluation of loss of material due to wear or corrosion and loss of bolting preload per the appropriate ASME B30 series standard. GALL Report AMP XI.M23 recommends that any visual indication of loss of material due to corrosion or wear and loss of bolting preload be evaluated in accordance with the appropriate ASME B30 series standard. 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 ensure that indications of the aging effects will be evaluated in accordance with the applicable ASME B30 series standard, consistent with the recommendations in the GALL Report.

Enhancement 4. LRA Section B2.1.12 states an enhancement to the "corrective actions" program element. In this enhancement, the applicant stated that the program will be enhanced to require repairs to cranes, hoists, and equipment handling systems per the appropriate ASME B30 series standard. GALL Report AMP XI.M23 recommends that repairs for all cranes, hoists, and equipment handling systems within the scope of license renewal be performed as specified in ASME B30.2 or other appropriate ASME B30 series standard. 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 ensure that repairs to cranes, hoists, and equipment handling systems are performed consistent with the recommendations in the GALL Report.

Based on its audit of the applicant's Inspection of Overhead Heavy Load and Light Load (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 enhancements associated with the "parameters monitored or inspected," "detection of aging effects," "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 B2.1.12 summarizes operating experience related to the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program. The LRA states that in a review of Callaway corrective action documents over a 10-year period none were found that identified corrosion or rail wear as a problem. The LRA also states that there were no occurrences of unacceptable corrosion, rail wear, or loose or missing fasteners for components within the scope of the Inspection of Overhead Load and Light Load (Related to Fuel Handling) Handling Systems 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. 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 that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.M23 was evaluated.

FSAR Supplement. LRA Section A1.12 provides the FSAR supplement for the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program. The staff reviewed this FSAR 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. 8) to implement the enhancements to the program six months before the period of extended operation for managing aging of applicable components during the period of extended operation.

The staff finds that the information in the FSAR supplement, as amended by letter dated February 28, 2013, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation through Commitment No. 8 six months before 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 FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.6 Fire Protection

Summary of Technical Information in the Application. LRA Section B2.1.13 describes the existing Fire Protection Program as consistent, with enhancements, with GALL Report AMP XI.M26, "Fire Protection." The LRA states that the Fire Protection Program is a condition and performance monitoring program that comprises tests and inspections that follow applicable National Fire Protection Association (NFPA) recommendations. The LRA also states that the program manages loss of material for fire rated doors, fire dampers, and the halon system; concrete cracking, spalling, and loss of material for fire barrier walls, ceilings, and floors; and increased hardness, shrinkage, and loss of strength for fire barrier penetration seals. The LRA further states that the program includes visual inspections of fire barrier penetrations seals, walls, ceilings, floors, coatings, wraps, doors, dampers, and halon systems; and functional tests of fire doors and halon systems.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.M26. For the "scope of program" 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.

GALL Report AMP XI.M26 is a fire barrier inspection program that includes aging management of fire barrier penetration seals, walls, ceilings, floors, doors, and other fire barrier materials within the "scope of program" program element. The LRA denotes AMR items with an intended function of fire barrier using an "FB." The staff noted that there are AMR items in LRA Table 3.5.2-1 for the hatch emergency airlock and hatch personnel airlock exposed to plant indoor air, which have an intended function of fire barrier, but are not being managed for aging using the Fire Protection Program. It was not clear to the staff how components with a fire barrier-intended function are being adequately managed for aging using alternative programs. By letter dated July 5, 2012, the staff issued RAI B2.1.13-1 requesting that the applicant explain how the items with a fire barrier function that are not being managed for aging using the Fire Protection Program are being adequately managed for aging using alternative programs.

In its response dated August 6, 2012, the applicant stated that the hatch emergency airlock and hatch personnel airlock are both fire barriers that will be managed for aging using the Fire Protection Program. The applicant revised LRA Table 3.5.2-1 to include AMR items to manage of loss of material for the hatch emergency airlock and hatch personnel airlock using the Fire Protection Program consistent with LRA Table 3.3-1, AMR item 3.3.1.059. The staff finds the applicant's response acceptable because the applicant is managing all the components with a fire barrier-intended function using the Fire Protection Program, consistent with the GALL Report recommendations. The staff's concern described in RAI B2.1.13-1 is resolved.

The "detection of aging effects" program element of GALL Report AMP XI.M26 states that visual inspections of fire barrier penetration seals, walls, ceilings, floors, doors, and other fire barrier materials are performed by fire protection-qualified personnel. LRA Section B2.1.13 states that the Fire Protection Program, following enhancement, will be consistent with GALL Report AMP XI.M26. During the audit, the staff noted that procedures QSP-ZZ-65045, Revision 13, "Fire Barrier Seal Visual Inspection," and QSP-ZZ-65046, Revision 13, "Fire Barrier Inspection," state that the personnel performing the inspections are quality control inspectors. The staff also noted that procedure OSP-KC-00015, Revision 8, "Fire Door Inspections," does not state what qualifications are required for personnel who perform the inspections.

Callaway's FSAR-SP, Section 9.5.1.6, and FSAR-SA, Appendix 9.5A, Section A.1 both state that FSAR-SA Section 9.5 discusses training for maintaining the competence of the station fire fighting and operating crew, including personnel responsible for maintaining and inspecting the fire protection equipment. However, the information regarding training of personnel who maintain and inspect fire protection equipment does not appear to be included in the FSAR-SP or FSAR-SA. RG 1.189, "Fire Protection for Nuclear Power Plants," states that personnel responsible for maintaining and testing fire protection systems should be qualified by training and experience for such work. However, neither the FSAR nor the LRA discuss the training and qualifications required for personnel responsible for performing Fire Protection Program inspections. By letter dated July 5, 2012, the staff issued RAI B2.1.13-2 requesting that the applicant explain the minimum training and qualifications required for personnel who perform Fire Protection Program inspections. The staff also requested the applicant to explain how only personnel with the required training and experience are assigned to perform Fire Protection Program inspections since a fire protection qualification is not used.

In its response dated August 6, 2012, the applicant stated that the personnel performing the Fire Protection Program inspections are qualified consistent with ASME N45.2.6-1978, "Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants." The applicant also stated that the quality control personnel are trained and qualified to perform their activities in accordance with procedure QCP-ZZ-01000, "QC Inspector Qualification." The applicant further stated that the operations personnel who perform fire door inspections are qualified by a specific watch station qualification program. However, the applicant did not discuss any specific fire protection-related training or qualifications required for personnel performing Fire Protection Program inspections. The staff noted that ASME N45.2.6-1978 requires that personnel performing inspections be qualified within their respective areas of responsibility. The staff also noted that the personnel performing Fire Protection Program inspections are quality control or operations personnel. It remained unclear to the staff how only personnel with the required training and experience in fire protection are assigned to perform Fire Protection Program inspections since a fire protection qualification is not used. Therefore, by letter dated October 1, 2012, the staff issued RAI B2.1.13-2a requesting that the applicant explain the specific fire protection-related training and experience that the quality control and operations personnel who perform Fire Protection Program inspections receive, and how only the personnel with fire protection-related training and experience are used to perform Fire Protection Program inspections.

In its response dated October 31, 2012, the applicant stated that the quality control inspectors who perform Fire Protection Program inspections are certified Level II and Level III inspectors and that the inspections of fire barriers, penetration seals, or fireproofing are performed using Callaway surveillance procedures that contain specific acceptance criteria and have undergone review by the fire protection engineer and/or fire protection system engineer. In addition, the applicant stated that the operations personnel who perform fire protection program inspections are equipment operators who are also qualified to perform the job of "Equipment Operator Inside (Watchstation Qualified)." The applicant stated that "[a]n individual with this qualification has completed an [i]nside [e]quipment [o]perator qualification card which requires demonstrated proficiency in the areas of responsibility for an [i]nside [o]perator, including familiarity with the fire protection system through a [f]ire [p]rotection [s]ystem [w]alkdown [c]heckout." The staff finds the applicant's response acceptable because fire protection program inspection procedures have been reviewed by fire protection engineers, and the Level II and Level III quality control inspectors are capable of performing inspections in accordance with those procedures and evaluating the validity and acceptability of the inspection results. In addition, the qualification of operations personnel who perform fire protection program inspections provides sufficient training to allow those personnel to validate the operability of fire barriers. The staff's concern described in RAI B2.1.13-2a is resolved.

The staff also reviewed the portions of the "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements associated with the 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 B2.1.13 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements. In this enhancement, the LRA states that procedures will be enhanced to include visual inspections of the external surfaces of halon fire suppression system components for excessive loss of material caused by corrosion. GALL Report AMP XI.M26 recommends that visual inspections of halon systems be performed to detect any signs of corrosion. 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 ensure halon system visual inspections are performed consistent with the recommendations in the GALL Report.

Enhancement 2. LRA Section B2.1.13 originally stated an enhancement to the "monitoring and trending" program element to enhance procedures to include trending of the performance of the halon system during testing. By letter dated April 25, 2012, the applicant revised the LRA (LRA Amendment 1) to delete this enhancement because the procedure changes have been completed.

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M26 and finds it acceptable because it ensures that halon system testing is trended consistent with the recommendations in the GALL Report.

Based on its audit and review of the applicant's responses to RAIs B2.1.13-1, B2.1.13-2 and B2.1.13-2a, the staff finds that program elements one though six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M26. In addition, the staff reviewed the enhancements associated with the "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 B2.1.13 summarizes operating experience related to the Fire Protection Program. The LRA states an operating experience example in which a degraded fire barrier penetration seal was discovered by inspection before any leakage occurred. The seal was subsequently repaired. The LRA states another operating experience example in which a small section of structural steel fireproofing was found degraded during an inspection and repaired.

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 that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.M26 was evaluated.

FSAR Supplement. LRA Section A1.13 provides the FSAR supplement for the Fire Protection Program. The staff reviewed this FSAR 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, as amended by letters dated April 25, 2012, and December 20, 2013, the applicant stated that the enhancements described in Commitment No. 9 have been completed.

The staff finds that the information in the FSAR supplement, as amended by letter dated February 28, 2013, 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 enhancements and confirmed that their implementation through Commitment No. 9 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 FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.7 Fire Water System

Summary of Technical Information in the Application. As amended by letter dated December 20, 2013, LRA Section B2.1.14 describes the existing Fire Water System Program as consistent, with exceptions and enhancements, with GALL Report AMP XI.M27, "Fire Water System." The LRA states that the program manages loss of material and flow blockage for water-based fire protection systems, including piping, fittings, valves, fire pump casings, sprinklers, nozzles, hydrants, hose stations, standpipes, and water storage tanks. The LRA also states that the program includes flow testing, visual inspections, and sprinkler inspections performed consistent with NFPA codes and standards. The program also includes pipe wall thickness examinations and internal inspections of fire water piping. In addition to NFPA codes and standards, portions of the water-based fire protection system that are normally dry but periodically subject to flow that cannot be drained or allow water to collect are subjected to augmented testing or inspections. Also, portions of the system are normally maintained at operating pressure and monitored such that loss of system pressure is immediately detected and corrective actions are initiated. Samples are collected for MIC quarterly and when fire water piping and components are opened for maintenance or are accessible. Biofouling is prevented by periodically adding treatment chemicals such as an anti-scalant, a biopenetrant, and a biostat to the fire water system and when monitoring indicates they should be added. The staff notes that, as amended by letter dated April 23, 2014, the Fire Water System program manages loss of coating integrity on the internal surfaces of the fire water storage tanks.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.M27. For the program description and "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 program description and "detection of aging effects" program element of GALL Report AMP XI.M27 recommend that sprinklers that have been in place for 50 years be replaced or a representative sample of sprinklers be field service tested at a recognized testing laboratory in accordance with NFPA 25, "Inspection Testing and Maintenance of Water-Based Fire Protection Systems." The LRA states that sprinklers will be replaced before 50 years in service or a representative sample of sprinklers will be tested, with testing repeated every 10 years. The Fire Water System Program does not discuss what type of testing will be performed or that testing will be performed in accordance with NFPA 25; therefore, it was unclear to the staff whether these statements are consistent with the GALL Report. By letter dated July 5, 2012, the staff issued RAI B2.1.14-1 requesting that the applicant clarify whether sprinkler field service testing will be performed at a recognized testing laboratory in accordance with NFPA 25. If sprinkler field service testing will not be performed at a recognized testing laboratory in

accordance with NFPA 25, the staff asked the applicant to explain the testing that will be performed, including test methods and acceptance criteria, and how this testing satisfies the guidance in NFPA 25.

In its response dated August 6, 2012, the applicant revised the LRA to clarify that it will replace sprinkler heads before reaching 50 years in service or test a representative sample of sprinklers at a recognized testing laboratory in accordance with NFPA 25, with additional representative samples of sprinklers tested at 10-year intervals thereafter. The staff finds the applicant's response acceptable because sprinkler head testing or replacement will be performed in accordance with NFPA 25, which is consistent with the recommendations in GALL Report AMP XI.M27. The staff's concern described in RAI B2.1.14-1 is resolved.

The program description and the "detection of aging effects" program element of GALL Report AMP XI.M27 recommend that sprinklers be tested in accordance with applicable NFPA codes and standards. NFPA 25 states that any sprinklers that show signs of physical damage, corrosion, or loading shall be replaced. In the first operating experience example of the "operating experience" program element, the LRA states that in 2005, 10 sprinkler heads were found with corrosion or damage. The LRA also states that two sprinkler heads were replaced and that the rest were cleaned. Review of CAR 200502420 during the audit identified that there were four sprinklers with damage, three with corrosion, and three with lint, but only two were documented as being replaced. It is unclear to the staff why only two of the sprinklers with identified damage, corrosion, or loading were replaced. This does not appear to be consistent with the guidance in NFPA 25 and, therefore, does not appear to be consistent with the recommendations in the GALL Report. By letter dated July 5, 2012, the staff issued RAI B2.1.14-2 requesting that the applicant explain why some of the corroded or damaged sprinklers were not replaced and why this is consistent with the guidance in NFPA 25 and GALL Report AMP XI.M27.

In its response dated August 6, 2012, as supplemented by letter dated August 21, 2012, the applicant stated that six of the sprinklers were cleaned to remove lint or tarnish, two were immediately replaced, and two had bent diffusers that were originally repaired but later replaced. The applicant also stated that the subject nozzles were evaluated to be fully functional as part of the remedial actions taken in the CAP.

The staff finds the applicant's response acceptable because cleaning and replacement of the sprinklers as well as the evaluation to confirm the full functionality of the sprinkler heads are adequate corrective actions. The staff's concern described in RAI B2.1.14-2 is resolved.

Subsequent to the applicant's submittal of its LRA, the staff issued LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," which revised several AMPs including the guidance for AMP XI.M27, "Fire Water System." By letter dated October 7, 2013, the staff issued RAI 3.0.3-3 requesting that the applicant either describe how its Fire Water System program already addresses the issues identified in this revised guidance or provide adequate justification why its program does not need to address them.

In its response dated December 20, 2013, the applicant stated that:

(a) The Fire Water System program will include the tests and inspections described in AMP XI.M27 Table 4a except for the following:

- The fire pumps do not have suction screens and therefore NFPA 25 Section 8.3.3.7 is not applicable.

- Main drain tests are not conducted (NFPA Section 13.2.5). Alternative testing and inspections were cited as the basis for not conducting main drain tests, including annual fire protection loop flow tests; fire protection water system flushes; hydrant flushes; and wet pipe, deluge, and preaction system visual inspections.

  The staff noted that the basis for the exception lacked sufficient detail for it to conclude that the listed alternative tests and inspections are capable of detecting potential flow blockage in system risers. By letter dated March 25, 2014, the staff issued RAI 3.0.3-3a Request (1) requesting that the applicant describe the alternative tests and inspections with sufficient detail to demonstrate that they are capable of detecting potential flow blockage in system risers.

  In its response dated April 23, 2014, the applicant stated that, to address flow blockage, flow testing (verifying that the water supply provides the design pressure at the required flow) is performed at the hydraulically most limiting location in each major structure every 5 years, including two locations in the reactor building, three locations in the auxiliary building, one location in the radwaste building, two locations in the control building, and five locations in the turbine building. Every 3 years, each hose station valve is partially opened to verify no flow blockage. The hydraulically most limiting hose stations are normally located at the most remote point from the main header piping. Using these locations would include the risers and some distribution piping in the test flow path, whereas, use of the drain valves does not include the risers or the distribution piping to hose stations and spray systems in the flow path and would not reveal any obstructions to flow in that piping. In addition, annual main drain tests per NFPA Section 13.2.5 will be performed on a representative sample of 20 percent of the main drains within the scope of license renewal. There are 21 main drain valves within the scope of license renewal, so that 5 main drain tests will be performed annually. During annual testing one of the tests is performed in a radiologically controlled area.

  The staff noted that LR-ISG-2012-02 states that the purpose of the test and inspections associated with AMP XI.M27 Table 4a is to provide "inspections and tests that are related to age-managing applicable aging effects that are associated with loss of material and flow blockage for passive long-lived in-scope components in the fire water system." The staff also noted that the purpose of flow tests and main drain tests is to detect potential flow blockage. The staff further noted that NFPA 25 (2014 Edition) Sections 13.2.5 and 13.2.5.1 allow a reduced number of main drain tests to be conducted. It states: "[a] main drain test shall be conducted annually for each water supply lead-in to a building water-based fire protection system to determine whether there has been a change in the condition of the water supply. Where the lead-in to a building supplies a header or manifold serving multiple systems, a single main drain test shall be permitted." The staff noted that testing 20 percent of the in-scope components is consistent with the extent of sampling in several GALL Report AMPs including XI.M32, XI.M33, and XI.M38.

The staff finds the applicant's response acceptable because: (a) the alternative flow tests and hose station testing, both in number and scope of locations, provide insights concerning potential accumulation of corrosion products that are comparable to those gained from main drain testing; (b) in regard to the number of tests, the applicant has proposed to periodically perform 13 flow tests every 5 years and every hose station valve is tested every 3 years; (c) in regard to the scope of testing, the testing will encompass piping located in five different buildings and every fire hose station is tested to ensure there is an open flow path; therefore, all buildings with in-scope components that are protected by the fire water system are tested in some manner; and (d) on an annual basis, 20 percent of the in-scope main drains will be tested in accordance with NFPA 25. As a result the testing will provide adequate trendable results to determine if flow blockage is occurring in the piping. The staff's concern described in RAI 3.0.3-3a Request (1) is resolved.

- The water spray fixed systems do not have main line strainers and therefore NFPA 25 Sections 10.2.1.7 and 10.2.7.1 are not applicable.

- The station does not have a foam water sprinkler system and therefore NFPA 25 Sections 11.2.7.1, 11.3.2.6, and storage tank inspections are not applicable.

- The response to RAI 3.0.3-3 Request (a) states, "[t]he internal surface of piping and branch lines is inspected for foreign material every five years by flushing wet pipe system piping." The response to Request (b) states, "[i]nternal visual inspections are performed during plant maintenance activities and the five year flush of wet pipe system piping."

  The staff noted that the response to RAI 3.0.3-3 Request (a) related to NFPA 25 Section 14.2 internal inspections appears to rely solely on flushes and not internal visual inspections. The staff has concluded that inspections conducted in accordance with NFPA 25 Section 14.2 should include internal visual inspections. While flushing procedures can detect loose corrosion products, internal conditions such as tubercules (NFPA Section 14.2.1.2) may not be detected with a flush. The response to Request (b) states that internal visual inspections will be conducted during maintenance activities and the 5-year flush of wet pipe systems; however, the minimum amount or percentage of piping that will be visually inspected was not stated. By letter dated March 25, 2014, the staff issued RAI 3.0.3-3a Request (3) requesting that the applicant state the minimum amount of wet pipe system piping, excluding private fire service main piping, that will be internally visually inspected on a 5-year basis.

  In its response dated April 23, 2014, the applicant stated that it will perform inspections as recommended by NFPA 25 Section 14.2 (i.e., half of the systems in each building at 5-year intervals) on the eight in-scope wet-pipe systems. If sufficient foreign material is detected all the systems in the building will be inspected in that interval. The applicant also stated that the in-scope dry-pipe preaction systems are normally dry and pressurized with instrument air. These systems will be internally visually inspected following actuation, prior to return to service. The applicant further stated that, if sufficient foreign material is found to obstruct the piping or sprinklers, an obstruction investigation will be conducted in accordance with NFPA 25 Annex D. If the visual inspection detects surface

irregularities that could be indicative of wall loss below nominal pipe wall thickness, followup volumetric examinations will be performed.

The staff noted that GALL Report item AP-4 states that there are no aging effects requiring management and no recommended AMPs for steel piping exposed to dry air (equivalent of instrument air). The staff finds the applicant's response acceptable because: (a) the inspections of the wet-pipe systems are consistent with LR-ISG-2012-02 AMP XI.M27 and NFPA 25; (b) although NFPA 25 Section 14.2.1.5 recommends periodic internal inspections of dry-pipe and preaction systems, corrosion would not be anticipated based on the conditions of the air in the system; and (c) augmented inspections will be conducted on normally dry piping that is periodically subject to flow and where drainage may not occur as expected as described below in the response to RAI 3.0.2-3 Request (d). The staff's concern described in RAI 3.0.3-3a Request (3) is resolved.

The staff finds the applicant's response to RAI 3.0.3-3 Request (a) acceptable because the fire water system inspections and tests are either consistent with LR-ISG-2012-02 AMP XI.M27, which recommends sufficient inspections and tests (when accompanied by other testing and inspections recommended in AMP XI.M27), or the applicant has provided a sufficient basis for exceptions. The staff's concern described in RAI 3.0.3-3 Request (a) is resolved.

(b) "[w]hen internal visual inspections are used to detect loss of material, the inspection technique will be capable of detecting surface irregularities that could indicate wall loss to below nominal pipe wall thickness due to corrosion and corrosion product deposition. Where such irregularities are detected, follow-up volumetric wall thickness examinations will be performed."

The staff finds the applicant's response to RAI 3.0.3-3 Request (b) acceptable because it is consistent with LR-ISG-2012-02 AMP XI.M27. The staff's concern described in RAI 3.0.3-3 Request (b) is resolved.

(c) "[w]all thickness examinations are not used in lieu of conducting flow tests or internal visual examinations."

The staff finds the applicant's response to RAI 3.0.3-3 Request (c) acceptable because it is consistent with LR-ISG-2012-02 AMP XI.M27. The staff's concern described in RAI 3.0.3-3 Request (c) is resolved.

(d) The portions of the fire water system that are periodically subject to flow, but designed to be normally dry, will be identified and inspected prior to the period of extended operation. For those piping segments where drainage may not occur as expected (susceptible piping): (a) either a flow test or flush sufficient to detect potential flow blockage, or a visual inspection of 100 percent of the internal surface of the piping segments that cannot be drained or allow water to collect will be conducted; (b) inspections will be performed in each 5-year interval beginning 5 years prior to the period of extended operation; (c) a 100 percent baseline inspection will be performed prior to the period of extended operation with 20 percent of the inspections performed in each five year interval of the period of extended operation. The acceptance criterion is no debris that could obstruct pipe or sprinklers and minimum design wall thickness is maintained. In addition, in each 5-year interval of the period of extended operation, 20

percent of the length of piping segments that cannot be drained or that allow water to collect will be subject to volumetric wall thickness examinations. The 20 percent of piping that is periodically inspected in each 5-year interval will be in different locations than previously inspected piping. If the results of a 100 percent internal visual inspection are acceptable, and the segment is not subsequently wetted, no further augmented tests or inspections will be performed.

The staff finds the applicant's response to RAI 3.0.3-3 Request (d) acceptable in part. Conducting a flow test, flush or internal visual examination of 100 percent of the susceptible piping prior to the period of extended operation, and volumetrically determining wall thickness of 20 percent of the susceptible piping every 5 years is consistent with the augmented inspection recommendations of LR-ISG-2012-02 AMP XI.M27. However, it is not clear to the staff that conducting a flow test, flush or internal visual examination of 20 percent of the susceptible piping during the period of extended operation is sufficient to provide reasonable assurance that the flow blockage will not occur in this piping. The staff also noted that LRA Section B.2.14 states that 100 percent of the susceptible piping would be subject to a flow test, flush or internal visual examination; however, as documented above, this conflicts with the RAI response. By letter dated March 25, 2014, the staff issued RAI 3.0.3-3a Request (2) requesting that the applicant provide the basis for why there is reasonable assurance that flow blockage will not occur in this piping.

In its response dated April 23, 2014, the applicant revised the response to RAI 3.0.3-3 Request (d) to state that 100 percent of the susceptible piping will have a flow test, flush or internal visual examinations in each 5-year interval, beginning 5 years prior to the period of extended operation.

The staff finds the applicant's revised response acceptable because the responses to RAI 3.0.3-3 Request (d) and RAI 3.0.3-3a Request (2) are now consistent with the augmented inspections recommended in LR-ISG-2012-02 AMP XI.M27. The staff's concern described in RAI 3.0.3-3 Request (d) and RAI 3.0.3-3a Request (2) is resolved.

(e) LRA Sections A1.14, B1.15, B2.1.14, and B2.1.15 were revised to include the fire water storage tanks within the scope of the Fire Water System program in lieu of the Aboveground Metallic Tanks program.

The staff finds the response to RAI 3.0.3-3 Request (e) acceptable because it is consistent with LR-ISG-2012-02 AMP XI.M27, which recommends that aging effects associated with fire water storage tanks be managed by the Fire Water System program. The staff's concern described in RAI 3.0.3-3 Request (e) is resolved.

The staff also reviewed the portions of the "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements associated with exceptions and enhancements to determine if the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these exceptions and enhancements follows.

Exception 1. LRA Section B2.1.14 states an exception to the "detection of aging effects" program element. In this exception, the applicant stated that it will perform power block hose station gasket inspections at least once every 18 months, which is in accordance with the applicant's existing NRC-approved Fire Protection Program. GALL Report AMP XI.M27 recommends that gasket inspections be performed annually. During the audit, the staff

reviewed plant operating experience and did not identify any examples of gasket failures. The staff also reviewed recent gasket inspection results and noted that a minimal number of gaskets required replacement when inspected. The staff reviewed this exception against the corresponding program element in GALL Report AMP XI.M27 and finds it acceptable because the existing gasket inspection frequency is based on the NRC-approved Fire Protection Program and is adequate to identify degradation before loss of intended function. Also, given that gaskets are replaced periodically, an increased frequency of inspection would not be required as the plant enters the period of extended operation because the overall average age of the gaskets should not change. Therefore, current inspection results would be expected to be similar.

Exception 2. LRA Section B2.1.14 states an exception to the "detection of aging effects" program element. In this exception, the applicant stated that it will perform hydrostatic hose testing for hose stations that are more than 5 years old on a 3-year frequency. The staff noted that the "detection of aging effects" program element of GALL Report AMP XI.M27 recommends that fire hoses be hydrostatically tested annually in accordance with NFPA codes and standards. During the audit, the staff noted that hydrostatic testing had not been performed since 2007. The staff also noted that CAR 201110777 documents the failure of a fire hose when it was charged during fire brigade training in 2011. The staff noted that hydrostatic testing is not being performed in accordance with the frequency outlined in the existing Fire Protection Program or the frequency recommended in GALL Report AMP XI.M27. The staff also noted that its review of plant-specific operating experience revealed a hose failure, which occurred during testing at the existing frequency. It is not clear to the staff, therefore, why the existing frequency is acceptable to ensure detection of fire hose degradation before loss of the intended function. By letter dated July 5, 2012, the staff issued RAI B2.1.14-3 requesting that the applicant provide justification for why the existing fire hose hydrostatic testing frequency is adequate to identify degradation of fire hose before loss of intended function.

In its response dated August 6, 2012, the applicant stated that it has two categories of fire hoses—fire brigade hose and interior fire hose—for the fire hose stations. The applicant also stated that fire brigade hose will be tested annually, as recommended in GALL Report AMP XI.M27. The applicant revised the LRA to include an enhancement, discussed later in this section, to perform annual hydrostatic hose testing for the fire brigade hose. The applicant further stated that interior fire hose for fire hose stations is tested 5 years from installation and every 3 years thereafter, in accordance with its previously approved Fire Protection Program, as described in FSAR-SP Table 9.5.1-2.

The staff noted that NFPA 1962, "Standard for the Inspection, Care, and Use of Fire Hose, Couplings, and Nozzles, and the Service Testing of Fire Hose," outlines different hydrostatic hose testing frequencies for an occupant use hose and a fire brigade hose. NFPA 1962 states that an occupant use hose shall be service-tested 5 years after manufacture and every 3 years thereafter, and fire brigade hoses shall be service-tested annually. The staff finds the applicant's response acceptable because fire brigade hoses will be hydrostatically tested annually as recommended in the GALL Report, and fire hoses for fire hose stations will be tested consistent with the applicant's CLB and NFPA 1962. The staff's concern described in RAI B2.1.14-3 is resolved. The staff reviewed this exception against the corresponding program element in GALL Report AMP XI.M27 and finds it acceptable because fire hose testing will be performed in accordance with NFPA codes and standards, which is consistent with the GALL Report recommendations.

Exception 3. LRA Section B2.1.14 originally stated an exception to the "detection of aging effects" program element. In this exception, the applicant stated that it will perform fire hydrant flow tests every 3 years. The "detection of aging effects" program element of GALL Report AMP XI.M27 recommends that fire hydrants be flow tested annually in accordance with NFPA 25. The staff reviewed the results of the last three sets of fire hydrant flow tests. The staff noted that testing performed in 2011 indicated that approximately 25 percent of the hydrants tested failed to drain in the required time frame. The testing performed in 2007 indicated that approximately 20 percent of the hydrants tested failed to drain properly, and testing performed in 2005 indicated that approximately 50 percent of the hydrants tested failed to drain as required. It is not clear to the staff how the existing frequency of 3 years is acceptable to identify degradation before loss of intended function, given that the recent performances of the hydrant flush have resulted in 20 to 50 percent of the hydrants failing. By letter dated July 5, 2012, the staff issued RAI B2.1.14-4 requesting that the applicant provide justification for why the existing hydrant flow testing frequency is adequate to identify degradation of the fire hydrants before loss of intended function.

In its response dated August 6, 2012, the applicant stated that the Fire Water System Program will be enhanced to include annual flow testing of fire hydrants consistent with NFPA 25. The applicant revised the LRA to delete this exception and include a new enhancement. The staff's evaluation of the enhancement is discussed later in this section. The staff finds the applicant's response acceptable because the exception has been deleted and an enhancement has been added to test fire hydrants consistent with the recommendations in GALL Report AMP XI.M27. The staff's concern described in RAI B2.1.14-4 is resolved.

Exception 4. As amended by letter dated December 20, 2013, LRA Section B2.1.14 contains an exception to the "detection of aging effects" program element. In this exception, the applicant stated that main drain tests are not conducted; however, as amended by letter dated April 23, 2014, the applicant deleted this exception based on the response to RAI 3.0.3-3a Request (1), above.

Enhancement 1. LRA Section B2.1.14, as amended by letter dated August 6, 2012, states an enhancement to the "preventive actions" program element. The applicant stated that the internal surfaces of the fire water storage tanks (FWSTs) will be recoated before the period of extended operation. As part of the Aboveground Metallic Tanks Program, the applicant identified corrosion, blistering, and delamination of the coating inside the FWSTs. The staff's concern regarding aging management of the internal surfaces of FWSTs and evaluation of this enhancement is documented in SER Section 3.0.3.2.8 for the Aboveground Metallic Tanks Program.

Enhancement 2. As amended by letters dated October 31, 2012, and May 6, 2014, LRA Section B2.1.14 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements. The applicant stated that the program will be enhanced to include pipe wall thickness examinations every 3 years. Each 3-year sample will include at least three locations for a total of 100 feet of above-ground fire water piping, and the locations will be selected based on system susceptibility to corrosion or fouling and evidence of performance degradation during system flow testing or flushes. In addition, internal inspections will be performed on accessible exposed portions of fire water piping during plant maintenance activities. When visual inspections are used to detect loss of material, the inspection technique will be capable of detecting surface irregularities that could indicate wall loss below nominal pipe wall thickness due to corrosion and corrosion product deposition and if this occurs, followup volumetric wall thickness examinations will be performed.

The staff reviewed this enhancement against the corresponding program elements in GALL Report XI.M27, considering the plant-specific operating experience and the applicant's response to RAI B2.1.14-5a discussed below in the "operating experience" program element. The staff finds this enhancement acceptable because, when it is implemented, the associated inspections will be capable of detecting pipe wall degradation before an impact on the system's ability to perform its intended function(s).

Enhancement 3. LRA Section B2.1.14, as amended by letter dated August 6, 2012, states an enhancement to the "detection of aging effects" program element. The applicant stated that the program will be enhanced to include annual hydrostatic hose testing of fire brigade hose. The "detection of aging effects" program element of GALL Report AMP XI.M27 recommends that fire hoses be hydrostatically tested annually in accordance with NFPA codes and standards. 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 ensure fire brigade hose is hydrostatically tested consistent with the GALL Report recommendations.

Enhancement 4. LRA Section B2.1.14 states an enhancement to the "detection of aging effects" program element. The applicant stated that the program will be enhanced to replace sprinkler heads before 50 years in service or representative samples will be submitted for field-service testing by a recognized testing laboratory in accordance with NFPA 25. The program will field-service test additional representative samples every 10 years thereafter. GALL Report AMP XI.M27 recommends that sprinkler heads be tested before reaching the 50-year service life and at 10-year intervals thereafter. The staff reviewed this enhancement against the corresponding program element and the program description in GALL Report AMP XI.M27 and finds it acceptable because, when it is implemented, it will ensure sprinkler head testing is performed consistent with the recommendations in the GALL Report.

Enhancement 5. LRA Section B2.1.14, as amended by letter dated August 6, 2012, states an enhancement to the "detection of aging effects" and "acceptance criteria" program elements. The applicant stated that the program will be enhanced to include annual flow testing of fire hydrants in accordance with NFPA 25. The "detection of aging effects" program element of GALL Report AMP XI.M27 recommends that fire hydrants be flow tested annually in accordance with NFPA 25. 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 ensure fire hydrants are flow tested consistent with the recommendations in the GALL Report.

Enhancement 6. LRA Section B2.1.14 states an enhancement to the "monitoring and trending" program element. The applicant stated that the program will be enhanced to review and evaluate trends in flow parameters recorded during the NFPA 25 flow tests. GALL Report AMP XI.M27 recommends that results of system performance testing be monitored and trended. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M27 and finds it acceptable because, when it is implemented, it will ensure flow testing results are monitored and trended.

Enhancement 7. As amended by letter dated December 20, 2013, LRA Section B2.1.14 states an enhancement to the "parameters monitored or inspected" and "detection of aging effects" program elements. The applicant stated that the program will be enhanced to inspect the internal surface of piping and branch lines for foreign material every 5 years by flushing wet-pipe

system piping. However, as amended by letter dated April 23, 2014, based on the response to RAI 3.0.3-3a Request (3), above, this enhancement was deleted.

Enhancement 8. As amended by letter dated December 20, 2013, LRA Section B2.1.14 states an enhancement to the "parameters monitored or inspected" and "detection of aging effects" program elements. The applicant stated that the program will be enhanced to include augmented tests and inspections of wetted but normally dry piping segments that cannot be drained or that allow water to collect as described in the responses to RAI 3.0.3-3 Request (d) and RAI 3.0.3-3a Request (2) above. The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because, when it is implemented, the program will include augmented testing of wetted but normally dry piping segments that cannot be drained or that allow water to collect consistent with LR-ISG-2012-02 AMP XI.M27.

Enhancement 9. As amended by letter dated December 20, 2013, LRA Section B2.1.14 states an enhancement to the "detection of aging effects" program element. The applicant stated that the program will be enhanced to include checking for evidence of voids beneath the floor of the fire water storage tanks. The staff reviewed this enhancement against the corresponding program element in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because, when it is implemented, the program will include appropriate inspections of the tank bottom as recommended by LR-ISG-2012-02 AMP XI.M27 and NFPA 25 Section 9.2.6.5.

Enhancement 10. As amended by letter dated December 20, 2013, LRA Section B2.1.14 states an enhancement to the "detection of aging effects" program element. The applicant stated that the program will be enhanced to change the frequency of trip testing each deluge valve from every three years to every refueling outage. The staff reviewed this enhancement against the corresponding program element in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because, when it is implemented, the testing frequency of the deluge valves will be as recommended by LR-ISG-2012-02 AMP XI.M27 and NFPA 25 Sections 13.4.3.2.2 and 13.4.3.2.2.3, which allow testing to be conducted on a refueling outage interval due to the nature of the protected property.

Enhancement 11. As amended by letter dated December 20, 2013, LRA Section B2.1.14 states an enhancement to the "detection of aging effects" program element. The applicant stated that the program will be enhanced to change the frequency of spray/sprinkler nozzle discharge pattern tests from every three years to every refueling outage. The staff reviewed this enhancement against the corresponding program element in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because, when it is implemented, the test frequency of spray/sprinkler nozzle discharge patterns will be as required by NFPA 25 Section 10.3.4.3, as modified by LR-ISG-2012-02 AMP XI.M27 to permit testing on a refueling outage interval.

Enhancement 12. As amended by letter dated December 20, 2013, LRA Section B2.1.14 states an enhancement to the "detection of aging effects" program element. The applicant stated that the program will be enhanced to include the tests and inspections listed in NFPA 25 Section 9.2.7, items (1) through (6), whenever pitting, corrosion, or coating failure is found during the inspection of the fire water storage tanks. The staff reviewed this enhancement against the corresponding program element in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because, when it is implemented, when pitting, corrosion, or coating failure is found during the inspection of the fire water storage tanks, the additional tank and coating inspections recommended by LR-ISG-2012-02 AMP XI.M27 and NFPA 25 Section 9.2.7 will be conducted.

Enhancement 13. As amended by letter dated December 20, 2013, LRA Section B2.1.14 states an enhancement to the "acceptance criteria" program element. The applicant stated that the program will be enhanced to require the removal of foreign material if its presence is found during pipe inspections to obstruct pipe or sprinklers and that the source of the material is determined and corrected. The staff reviewed this enhancement against the corresponding program element in LR-ISG-2012-02 AMP XI.M27 and finds it acceptable because when it is implemented, the requirements are consistent with the "acceptance criteria" program element of LR-ISG-2012-02 AMP XI.M27.

Enhancement 14. As amended by letter dated April 23, 2014, LRA Section B2.1.14 states an enhancement to the "detection of aging effects" program element. The applicant stated that the program will be enhanced to perform annual main drain tests consistent with NFPA 25 Section 13.2.5 on a representative sample of 20 percent of the main drains within the scope of license renewal, including one in the radiologically controlled area, in order to check for potential flow blockage in system risers. The staff's evaluation of this enhancement is documented with the response to RAI 3.0.3-3a Request (1), above.

Enhancement 15. As amended by letter dated April 23, 2014, LRA Section B2.1.14 states an enhancement to the "detection of aging effects" program element. The applicant stated that the program will be enhanced to include inspections of wet-pipe and dry-pipe systems as described in the response to RAI 3.0.3-3a Request (3), above. The staff's evaluation of this enhancement is documented with the response to RAI 3.0.3-3a Request (3).

Based on its audit and review of the applicant's responses to RAIs B2.1.14-1, B2.1.14-2, B2.1.14-3, B2.1.14-4, 3.0.3-3, and 3.0.3-3a, 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 LR-ISG-2012-02 AMP XI.M27. The staff also reviewed the exceptions associated with the "detection of aging effects" 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 they are 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 Fire Water System Program. One operating experience example in the LRA states that there was a leak in the fire water system in 2005 that was identified by excessive jockey pump run times. CAR 200510105 clarifies that the leak was in buried piping on an isolable branch. Another operating experience example in the LRA states that a low cleanliness factor was identified during system flow testing and, as a result, chemical cleaning was performed on the fire water system in 2006 to improve the cleanliness factor. However, after chemical cleaning, five leaks developed, which were subsequently repaired.

The staff reviewed operating experience information in the application and during the audit to determine if the applicant reviewed the applicable aging effects and industry and plant-specific operating experience. As discussed in the audit report, the staff conducted an independent search of the plant operating experience information to determine if 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 noted that MIC contributed to the low cleanliness factor and leakage operating experience examples discussed in the LRA and that additional leaks occurred after the chemical cleaning. The staff also noted that system flow testing performed in 2011 identified a low cleanliness factor again and that compensatory measures were required to maintain system-intended function. The LRA states that flow testing is performed every 3 years and that pipe wall thickness examinations will be performed before the period of extended operation and every 10 years. Given that the fire water system degraded from a clean system in 2006 to a degraded system in 2011, in which compensatory measures were required to maintain system-intended function, it is not clear to the staff how the existing testing and inspection activities are adequate to ensure aging is identified before loss of intended function throughout the period of extended operation. By letter dated July 5, 2012, the staff issued RAI B2.1.14-5 requesting that the applicant do the following:

(a) List, for the past 10 years, each instance of internal or external degradation of the fire protection piping that resulted in either through-wall or significant penetration of the pipe wall, including any out-of-scope piping instances where the environment is similar to that of in-scope piping.

(b) Describe the results of general internal and external observations of the condition of the piping and coatings that have been conducted for the past 10 years.

(c) Project the condition of the internal and external surfaces of the fire protection system in-scope piping through the end of the period of extended operation.

(d) State the basis for why the configuration of the in-scope fire protection system will have sufficient structural integrity to meet all design loads throughout the period of extended operation. Include consideration of multiple flaws located in a configuration such that they cannot be considered as independent flaws.

(e) State how the inspections of the fire water system will be augmented to ensure that the assumptions used in the response to (d) above will be met throughout the period of extended operation.

In its response dated August 6, 2012, to RAI B2.1.14-5, Part (a), the applicant provided a summary of the internal and external degradation identified in fire protection piping from 2001–2012. The staff noted that the applicant identified two instances of leakage from the buried high-density polyethylene (HDPE) fire protection piping installed in 2007 that were attributed to poor fusion during installation. Although this fire protection piping is not within the scope of license renewal, similar replacements were performed in the in-scope ESW system.

The staff finds the applicant's response related to providing the past 10 years of plant-specific operating experience acceptable because the applicant's summary of occurrences of degradation provided the staff with an understanding of all the instances of internal or external degradation of the fire protection piping for the past 10 years, as well as the applicant's level of understanding of the cause of each event. However, the staff lacked sufficient information to conclude that poor fusion failures will not occur on the in-scope ESW piping, given that the fire water system failures did not reveal themselves for at least 3 months and upwards of 46 months after installation. By letter dated October 3, 2012, the staff issued RAI B2.1.14-5a, Part (a) requesting that the applicant state the basis for why the inspections being conducted in accordance with the Buried and Underground Piping and Tanks Program will be sufficient to detect poor fusion of in-scope ESW piping or state the basis for why this failure mechanism is not applicable to the piping.

In its response to RAI B2.1.14-5a, Part (a), dated October 31, 2012, the applicant stated that the ESW piping was designed and installed consistent with ASME Code Class 3 quality controls, whereas the fire water piping was installed as commercial grade piping; the fusion joints, which leaked, were not within the scope of license renewal; and the fusion process for the fire water system joints was not subject to the same quality controls as the ESW piping. The applicant also stated the following:

- The ESW HDPE material was traceable to the resin supplier and pipe manufacturer.
- The resin manufacturer performed burst testing in accordance with ASTM D 1599, "Standard Test Method for Resistance to Short-Time Hydraulic Pressure of Plastic Pipe, Tubing, and Fittings."
- Performance testing was conducted on fused joint test coupons.
- The fusion procedure, fusion machine and fusion machine operators were qualified.
- NDE was performed on the fused joints by qualified NDE inspectors.
- The joints were visually inspected, an ultrasonic time-of-flight diffraction examination was performed, and a hydrostatic test was conducted.

The applicant further stated that the ESW HDPE piping was installed in 2008 and early 2009, and none have leaked.

The staff finds the applicant's response acceptable because sufficient controls were established to provide reasonable assurance that the materials and installation processes were effective in regard to installing fused HDPE joints. In addition, the ultrasonic time-of-flight diffraction examination technique is an industry-recognized means of detecting cracking in joints (e.g., EN 583-6, "Non-destructive testing – Ultrasonic examination – Part 6: Time-of-flight diffraction technique as a method for detection and sizing of discontinuities," ASM Handbook, Volume 19, "Fatigue and Fracture," 1996, Time of Flight Measuring Techniques, page 217). This method is also endorsed in NUREG/CR-7136 PNNL-20300, "Assessment of NDE Methods on Inspection of HDPE Butt Fusion Piping Joints for Lack of Fusion" Section 3.3, "Ultrasonic Time-of-Flight Diffraction." The staff's concerns described in RAIs B2.1.14-5, Part (a), and B2.1.14-5a, Part (a), are resolved.

In its response, dated August 6, 2012, to RAI B2.1.14-5, Part (b), the applicant stated that there have been no failures in the fire protection system piping related to internal aging effects since 2001. The applicant also stated that, before the chemical cleaning, the system was susceptible to fouling because of corrosion products and tuberculation generated within the system itself, which caused the failed fire main flow test in 2004. Subsequent to the chemical cleaning conducted in 2006 to remove the corrosion products from the pipe wall, several leaks were revealed in out-of-scope piping. After chemical cleaning, the fire main flow test failed again in 2009 and 2011, but the applicant identified inaccuracies in the calculation and conservatisms that could be eliminated to achieve acceptable results, confirming the operability of the system. The applicant further stated (in the response to Part (d) of this RAI), that, in 2011, visual inspection of the internal and external surfaces of excavated fire hydrant piping was performed. The inspections identified no physical damage or breaks in the coating and found no signs of microbial infestation. In June 2012, internal visual inspections of seven different locations in the turbine building were performed, and no adverse conditions were noted. The applicant stated that biological corrosion of the internals of the piping is mitigated by the use of a biopenetrant and biostat.

The staff finds the applicant's response to RAI B2.1.14-5 Part (b) acceptable because sufficient general information was provided on the internal and external observations of the condition of the piping and coatings that have been conducted for the past 10 years for the staff to understand the fire water system conditions and evaluate the applicant's proposed aging management program. The staff's concern described in RAI B2.1.14-5 Request (b) is resolved. However, the staff noted the following in relation to flow testing results:

- Failure of the flow test in 2004 was attributed to accumulated corrosion products. The corrective action was to conduct chemical cleaning in 2006, and the subsequent flow test met acceptance criteria.
- Failure of the flow test in 2009 was attributed to a combination of factors related to the test procedure and the flow calculation, such as gauge elevation, rounding error, and rerouting of fire piping. Upon revision of the calculation and flow test procedure, the flow test met acceptance criteria.
- Failure of the flow test in 2011 was attributed to unnecessary conservatisms in the flow calculation, such as how much additional flow was assumed to hose stations and yard hydrants coincident with sprinkler demand, as compared to the licensing basis value. Additionally, the calculation used to determine pipe wall cleanliness was rewritten, including taking credit for actual fire pump performance. Upon revision of the calculations, the flow test met acceptance criteria.

Although the applicant has identified contributing factors to the flow test failures and has been able to revise the procedure to verify operability of the system, the test results indicate that the condition of the fire main is degrading, and the applicant has not identified a cause. For example, the 2006 test was passed without the improvements in the test's procedures and calculations identified during the analyses of the 2009 and 2011 test results. Likewise, the 2009 test was passed without the improvements in the calculations identified during the analysis of the 2011 test results. It was not clear to the staff what caused the extensive buildup of corrosion products and tuberculation that contributed to the failed fire main flow tests, and whether the existing flow testing frequency is adequate to identify degradation before loss of intended function given the repeat failures at the existing frequency.

The staff noted that the applicant identified four instances in which buried piping experienced leakage but the cause could not be determined because the piping was abandoned in place or isolated. As a result of two of these cases, the entire length of piping between the plant and the training center was abandoned in place, and new HDPE piping was installed. The applicant stated that these leaks occurred just after chemical cleaning of the system, yet the applicant did not attribute any leakage to internal aging effects other than fouling caused by corrosion products in its summary table in response to the staff's request. In addition, for at least one of the cases in which external corrosion was listed as the cause of the failure, the staff reviewed pictures of the failed piping during the audit, which indicated that loss of material because of internal corrosion also was present in the piping and could have contributed to the failure. It was unclear to the staff if the applicant has adequately evaluated whether loss of material caused by corrosion is contributing to leakage from the system.

By letter dated October 3, 2012, the staff issued RAI B2.1.14-5a, Part (b), requesting that the applicant state the cause of the extensive buildup of non-microbial corrosion products and tuberculation that contributed to the failed fire main flow tests and leakage that developed after chemical cleaning, the basis for acceptability of the existing fire main flow testing frequency for

identifying degradation before loss of intended function, and the basis for why loss of material caused by corrosion is not contributing to leakage from the system.

In its response dated October 31, 2012, the applicant stated that the 2004 flow test failure was caused by buildup of deposits because the steel piping was exposed to raw water for over 20 years and that chemical cleaning in 2006 was conducted to remove accumulated corrosion products. The applicant also stated that the inspection program described in the response to Part (d), below, will manage internal corrosion such that the system will be able to perform its intended function.

The staff finds the applicant's response acceptable, in part, because the wall thickness testing described below will be adequate to detect through-wall or partial-wall degradation of the piping before an impact on the ability of the system to perform its intended function. The staff's evaluation is below. However, the flow testing in 2004, 2006, 2009, and 2011 demonstrates a decreasing trend in fire water system flow performance. The staff lacked sufficient information to conclude that conducting flow testing every 3 years will provide reasonable assurance that the fire water system will perform its intended function during the period of extended operation. The staff's concerns, described in RAI B2.1.14-5a, Part (b), are not resolved. By letter dated January 14, 2013, the staff issued RAI B2.1.14-5b, Part (a), requesting that, in light of the decreasing trend in system performance, the applicant state the basis for why flow testing of the system every 3 years will be sufficient to ensure the system can perform its intended function during the period of extended operation.

In its response dated January 24, 2013, the applicant stated that, based on the performance trending of data from the 2006, 2009, and 2011 flow tests, the test will be conducted initially every two years in lieu of the three-year interval stated in the FSAR. This test frequency has been adopted to facilitate establishing a trend based on the current flow test procedures. The test results are trended to ensure that adequate margin, including anticipated degradation and corrective action, exists through the next flow test. The next flow test is scheduled for 2013. Given the procedurally-allowed 25 percent grace period for testing intervals, at least four and up to eight tests will be conducted prior to the period of extended operation. If a test yields results that do not meet the acceptance criteria established in the test, it will be documented in the Corrective Action Program. Depending on the results, the corrective actions for tests not meeting acceptance criteria could include pipe cleaning, refurbishment, or replacement.

The staff finds the applicant's response acceptable because (a) reducing the test interval from three years to two years is adequate to establish a trend of system performance using current flow test procedures, (b) unacceptable test results will be entered into the Corrective Action Program, and (c) there are corrective actions available that could restore margin if the trend is not acceptable (e.g., pipe cleaning, refurbishment, or replacement).

The staff's concerns described in RAI B2.1.14-5a, Part (b) and RAI B2.1.14-5b, Part (a), are resolved.

In its response dated August 6, 2012, to RAI B2.1.14-5, Part (c), the applicant stated that microbial corrosion inspections, coatings, and pipe wall thickness measurements will be used, as follows, to project the condition of the fire protection system piping through the period of extended operation:

- Opportunistic visual inspections are performed and MIC samples are obtained. If active MIC colonies are discovered, corrective actions are taken to mitigate the effects of MIC.

- Coatings and cathodic protection are used to protect the external surfaces of the fire protection system piping.
- The Fire Protection Program will be enhanced to conduct NDE testing to determine general wall thickness. A sampling plan will be used with locations selected based on susceptible locations identified from opportunistic inspections and chemistry sampling.

The staff finds the applicant's response acceptable, in part, because preventive actions for the external surfaces (i.e., coatings and cathodic protection) are used; biological corrosion of the piping internals is mitigated by the use of a biopenetrant and biostat (as stated in the reply to Part (b) of RAI B2.1.14-5); and opportunistic inspections and analyses are performed to confirm that MIC is not occurring. However, it was unclear to the staff why the MIC sampling plan and NDE testing plan are not credited for aging management of the fire water system for license renewal. By letter dated October 3, 2012, the staff issued RAI B2.1.14-5a, Part (c), requesting that the applicant include these activities in the Fire Water System Program for license renewal.

In its response dated October 31, 2012, to RAI B2.1.14-5a, Part (c), the applicant stated the following:

- MIC samples are collected quarterly and when fire water piping and components are opened for maintenance or are accessible.
- The MIC Index is trended to evaluate treatment effectiveness in specific locations.
- Biofouling is prevented by adding treatment chemicals such as an anti-scalant, a biopenetrant, and a biostat to the fire water system annually and when monitoring indicates they should be added.
- Wall thickness measurements will be performed on fire water piping every 3 years.

The applicant also stated that each 3-year sample will include at least three locations, for a total of at least 30.5 meters (100 feet) of above-ground fire water piping and will be selected based on system susceptibility to corrosion or fouling and evidence of performance degradation during system flow testing or flushes. Wall thickness measurements will use a LFET or an equivalent as a screening tool to identify "spots of interest," which are then followed up with UT testing on the spots of interest. With the exception of trending of the MIC index, LRA Sections A1.14 and B2.1.14 were revised to reflect the above as well as Commitment No. 10.

The staff finds the applicant's response acceptable, in part, because, with the exception of MIC Index trending, the applicant included MIC sampling, biofouling treatments, and wall thickness measurements into the program. However, the staff noted that the applicant did not revise LRA Section B2.1.14 to include MIC Index trending to evaluate treatment effectiveness in specific locations. The staff's concerns described in RAIs B2.1.14-5, Part (c) and B2.1.14-5a, Part (c) are resolved with the exception of MIC Index trending. By letter dated January 14, 2013, the staff issued RAI B2.1.14-5b, Part (b), requesting that the applicant revise LRA Section B2.1.14 to include MIC Index trending.

In its response dated January 24, 2013, the applicant revised LRA Sections B2.1.14 and A1.14 to include MIC Index trending.

The staff finds the applicant's response acceptable because the MIC Index provides input into chemical treatment effectiveness, and by revising the program and FSAR supplement, this

parameter will be utilized through the period of extended operation. The staff's concern described in RAI B2.1.14-5b, Part (b), is resolved.

In its response, dated August 6, 2012, to RAI B2.1.14-5, Part (d), the applicant stated that the internal surfaces of fire protection system piping are monitored through the Raw Water Systems Control Program and the Raw Water Predictive Maintenance Program. The Raw Water Systems Control Program performs MIC culture samples when piping becomes accessible. The Raw Water Preventive Maintenance Program ensures engineering performs inspections of the piping for structural integrity. The applicant also stated that, before 1996, the fire water was untreated, but that currently an anti-scalant, biopenetrant, and biostat are added to the FWSTs weekly and in conjunction with the yearly fire main flush.

The applicant further stated that the external surfaces of the fire protection system piping are managed by the Buried and Underground Piping and Tanks Program, which will be augmented for license renewal. It was unclear to the staff how opportunistic visual inspections of the fire water system piping are adequate to ensure the structural integrity of the piping, given the unknown cause of past piping failures and failed flow tests. It was also unclear to the staff why the activities in the Raw Water Systems Control and Raw Water Maintenance Programs, including the water treatment activities, are not credited for aging management of the fire protection system for license renewal. By letter dated October 3, 2012, the staff issued RAI B2.1.14-5a, Part (d), requesting that the applicant state the basis for why opportunistic visual inspections are adequate to ensure the structural integrity of the system and to include the activities of the Raw Water Systems Control and the Raw Water Predictive Maintenance Programs into the Fire Water System Program for license renewal.

In its response dated October 31, 2012, to RAI B2.1.14-5a, Part (d), the applicant repeated a summary of the examinations and testing described in the response to Part (c).

The staff finds the applicant's response acceptable because:

- Rather than crediting the Raw Water Systems Control and Raw Water Maintenance Programs' activities related to MIC sampling and wall thickness inspections for aging management of the fire protection system for license renewal, these provisions have been incorporated into the fire water system AMP.
- As described in the response to Part (d), LRA Sections A1.14 and B2.1.14 were revised to reflect the above as well as Commitment No. 10.
- Appropriate preventive actions are used to mitigate external and internal corrosion (i.e., coatings, cathodic protection, and chemical additions).
- Inspecting for wall thickness of 100 feet of pipe (over multiple locations) every 3 years, commencing after 2014 (reference Commitment No. 10), will result in 400 feet of pipe being inspected before the period of extended operation and an additional 600 feet during the period of extended operation. On a comparable basis, GALL Report AMP XI.M41, "Buried and Underground Piping and Tanks," Table 4a, "Inspections of Buried Pipe," recommends that 600 feet of piping be inspected starting ten years prior and extending through the end of the period of extended operation for a buried piping system that has adverse plant-specific OE. Based on this comparison, inspecting 1000 feet of pipe provides sufficient information to project the condition of the internal and external surfaces of the fire protection system in-scope piping through the end of the period of extended operation.

- In addition to a sufficient number of inspections being conducted, the applicant will inform the location of inspections based on system susceptibility to corrosion or fouling and evidence of performance degradation during system flow testing or flushes. This is consistent with GALL Report AMPs that use a sampling basis (e.g., AMP XI.M41, "Buried and Underground Piping and Tanks," AMP XI.M32, "One-Time Inspection").
- The staff's evaluation of using the LFET technique to screen for wall thickness degradation is documented in SER Section 3.0.3.2.8.

The staff's concerns addressed in RAIs B2.1.14-5, Part (d), and B2.1.14-5a, Part (d), are resolved.

In its response dated August 6, 2012, to RAI B2.1.14-5, Part (e), the applicant stated that the Fire Water System Program will be enhanced to include a sampling plan for performing NDE testing to determine general wall thickness. Locations will be selected based on susceptible locations and information from inspections and chemistry sampling. The staff noted that the applicant's enhancement states that the program will be enhanced to include non-intrusive pipe wall thickness examinations or internal visual inspections before the period of extended operation and at 10-year intervals thereafter. The enhancement does not discuss the basis for where inspections will be conducted or the basis for the 10-year frequency. From the information requested, there does not appear to be a corrosion rate established for the fire protection system piping; the staff also noted that failures have occurred much more frequently than 10 years apart. By letter dated October 3, 2012, the staff issued RAI B2.1.14-5a, Part (e), requesting that the applicant state the basis for the chosen inspection frequency, inspection sample size, and inspection location selection criteria and include this information in the Fire Water System Program.

In its response dated October 31, 2012, to RAI B2.1.14-5a, Part (e), the applicant stated that the basis for the inspection frequency (i.e., 100 feet of pipe covering 3 locations every 3 years) is that it is the same frequency as the yard fire loop flush and the flow tests of the fire water loops, which is set by FSAR Table 9.5.1-2 SP, items 2.4 and 2.7. The applicant reiterated the basis for sample location selection criteria as stated in Part (c) above. Also, as stated in Part (c) above, the Fire Water System Program was amended to address the sample size, frequency, and location selection basis for the wall thickness inspections.

The staff finds the applicant's response acceptable because the applicant (a) amended its program to inspect 100 feet of pipe covering 3 locations every 3 years as opposed to an unspecified number of inspections every 10 years, (b) inspection locations will be selected based on system susceptibility to corrosion or fouling and evidence of performance degradation during system flow testing or flushes, and (c) a frequency of 3 years is consistent and corresponds with the applicant's CLB as documented in FSAR Table 9.5.1-2 SP; therefore, the inspections are sufficient to provide reasonable assurance that degradation of pipe wall thickness will be discovered and corrected before impacting the ability of the system to perform its intended function(s), and the appropriate changes have been made to the program, FSAR Supplement and Commitment No. 10. The staff's concern described in RAI B2.1.14-5a, Part (e), is resolved.

Based on its audit, review of the application, and review of the applicant's response to RAIs B2.1.14-5, B2.1.14-5a, and B2.1.14-5b, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the

conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.M27 was evaluated.

FSAR Supplement. LRA Section A1.14, as amended by letters dated August 6, 2012, October 31, 2012, January 24, 2013, December 20, 2013, April 23, 2014, and May 6, 2014, provides the FSAR supplement for the Fire Water System Program. The staff reviewed this FSAR supplement description of the program and noted that it is consistent with the recommended description in LR-ISG-2012-02 Table 3.0-1. The staff also noted that the applicant committed (Commitment No. 10) to enhance the Fire Water System Program procedures to implement Enhancement Nos. 1–6 and 8-15 during the period of extended operation; with some program elements being implemented between 5 years and 6 months prior to the period of extended operation (Enhancements Nos. 1 and 8).

The staff noted that by letter dated April 23, 2014, the applicant amended Commitment No. 10 to state that it will revise the procedure and calculation used to change test and inspection frequencies associated with the NFPA 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants," license amendment (Amendment 206) to include the following restrictions:

- EPRI Report 1006756, "Fire Protection Equipment Surveillance Optimization and Maintenance Guide," will be used to adjust test and inspection frequencies.
- Data to be used in analyzing the potential for modifying test and inspection frequencies would not be obtained any earlier than 5 years prior to the [period of extended operation].
- A minimum sample size consistent with EPRI Report 1006756 Section 11.2 will be used to modify test and inspection frequencies.
- EPRI Report 1006756 would not be used to modify: fire water storage tank inspections/tests, underground flow tests, and inspections of normally dry but periodically wetted piping that will not drain due to its configuration.

The staff finds this change acceptable because: (a) use of EPRI Report 1006756 is consistent with the applicant's current licensing basis (ADAMS Accession No. ML13274A596); (b) modification of testing frequencies will be based on data obtained no earlier than 5 years prior to the period of extended operation which is consistent with GALL Report AMP XI.M33, which ensures that the in-scope components have had an adequate aging period prior to using inspections as input for determining potential changes to subsequent inspection intervals; (c) EPRI Report 1006756 Section 11.2 includes industry-standard guidance for selecting the number of data points to be used in potentially adjusting test and inspection frequencies; and (d) the applicant stated that it will not use the methodology to adjust the frequency of fire water storage tank inspections/tests, underground flow tests, and inspections of normally dry but periodically wetted piping that will not drain due to its configuration, which are included in the program based on plant-specific or industry operating experience.

The staff finds that the information in the FSAR supplement, as amended by letters dated through May 6, 2014, 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. 10 six months before 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 FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.8 Aboveground Metallic Tanks

Summary of Technical Information in the Application. LRA Section B2.1.15 describes the new Aboveground Metallic Tanks Program as consistent, with an exception, with GALL Report AMP XI.M29, "Aboveground Metallic Tanks." The LRA states that the AMP manages the effects of cracking and loss of material for the condensate storage tank (CST), refueling water storage tank (RWST), and the two FWSTs, which are exposed to outdoor air and supported on concrete foundations. The LRA also states that the AMP proposes to manage these aging effects through coatings on the external surface and edge grouting at the base of the FWSTs, as well as jacketed insulation that prevents moisture intrusion for the CST and RWST. The LRA further states that periodic visual inspections of the external surfaces and thickness measurements of the bottom of the FWSTs will be conducted. The LRA states that the insulation covering for the CST and RWST will be inspected for damage, thickness measurements of the walls of tanks will be conducted when insulation has not been opportunistically removed, and thickness measurements of the bottom of the tanks will be conducted.

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.M29.

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.M29 states that sealant or caulking may be applied at the external surface of the interface joint between a tank and its concrete foundation to minimize the amount of water penetrating the interface, which could lead to corrosion of the tank bottom. However, during its audit, the staff found that the applicant's Aboveground Metallic Tanks Program states that there are no sealants or caulking applied at the external interface between the bottoms of the CST and RWST and their concrete foundations. By letter dated July 5, 2012, the staff issued RAI B2.1.15-1 requesting that the applicant state the basis for why the proposed inspection schedule of the CST and RWST tank bottom volumetric inspections is sufficient to provide reasonable assurance that the tanks will meet their intended function(s) during the period of extended operation.

In its response dated August 6, 2012, the applicant stated that the tank foundations for the CST and RWST are designed using a radial slope. It also stated that the high point of the foundation is located at the tank centerline, allowing collected liquid to flow down and away from the base of the tanks, and caulking or sealant at the external interface of the tank bottoms and their foundations would impede this design by preventing water from flowing outward, trapping water between the tank and foundation. According to the applicant, the free draining design of the foundations and the tank bottom thickness inspection frequency (i.e., once within 5 years of entering the period of extended operation and whenever the tanks are drained) will provide

reasonable assurance that degradation will be detected and corrective actions taken before loss of intended function.

The staff finds the applicant's response acceptable because the design of the tank foundation is such that water would not penetrate the interface between the tank bottom and concrete foundation for any appreciable amount of time because (1) water would drain out from under the tank, (2) installation of caulking or sealant would cause water not to drain from under the tank, (3) no signs of corrosion were found at the interface between the tanks and their foundations during the staff's walkdowns of these tanks, and (4) the program's inspection frequency is consistent with GALL Report AMP XI.M29. The staff's concern described in RAI B2.1.15-1 is resolved.

The "preventive actions" program element in GALL Report AMP XI.M29 recommends that "[i]n accordance with industry practice, tanks may be coated with protective paint or coating to mitigate corrosion by protecting the external surface of the tank from environmental exposure." However, during its audit, the staff found that the applicant's Aboveground Metallic Tanks Program states, in part, the following:

- The stainless steel CST does not have a protective coating, the insulation materials have a documented evaluation demonstrating that there are not any harmful substances that could leach onto the tank surface, and the insulation has a protective aluminum jacket with overlapping seams. In contrast to these statements, LRA Table 3.4.2-6, Insulation, plant-specific note 3, states, in part, "[t]he dome of the stainless steel tank is prepped with a low halogen (<200 parts per million (ppm)) primer before the application of the foam urethane."
- The stainless steel RWST does not have a protective coating, and the insulation has a protective aluminum jacket with overlapping seams.

During the staff's walkdown of the structure that partially encloses the CST, water stains were observed on the side of the tank where insulation is not installed. By letter dated July 5, 2012, the staff issued RAI B2.1.15-2 requesting that the applicant provide information. The applicant's response and the staff's evaluation of the response are provided below.

- Part (a): State whether there is or could be the potential for chemical compounds in the cooling tower water, soil, or other sources to migrate to the CST or RWST insulation jacketing or tank external surfaces.

  Part (f): State whether chemical treatments of cooling tower water will contain chemical compounds that could cause cracking, pitting, or crevice corrosion on the external surfaces of the tank, and propose a schedule for periodic site soil samples that will demonstrate that harmful compounds have not accumulated on the soil surface due to prior treatments.

  In its response to Part (a) dated August 6, 2012, the applicant stated:

  > There has been no operating experience indicating negative effects of chemical compounds in the cooling tower water, soil, or other sources on the surfaces of the CST or RWST. The range of cooling water chemicals includes biocides, bleach, coagulant aids, cationic polymers, bromine, HEDP (hydoxyethylidine diphosphonic acid), pyrophosphate, sodium tolytriazole, biopenetrant, and sulfuric acid.

In its response to Part (f) dated August 6, 2012, the applicant stated that during the period of extended operation, chemical treatments of cooling tower water will not contain chemical compounds that could cause cracking, pitting, or crevice corrosion on the external surfaces of the tanks; within 5 years of entering the period of extended operation a one-time soil surface sample near the CST and RWST will be performed; and the soil surface sample will be evaluated to ensure that chlorides or other aggressive cooling tower water treatment chemicals are not creating an aggressive environment that would degrade the CST, RWST, or their insulation jacketing. The applicant also revised LRA Appendix A1.15 and LRA Appendix B2.1.15 to reflect the above.

The staff did not find the applicant's response to Part (a) in and of itself acceptable because the applicant only cited plant-specific operating experience to date. Given that there are more than 12 years before entry into the period of extended operation, existing operating experience is not sufficient to predict degradation that could occur during the period of extended operation. In addition, the response did not cite specific inspections that have been performed to conclude that no negative effects are occurring. Finally, based on the list of cooling water chemicals, some have been known to cause loss of material or cracking of stainless steel. However, the staff finds the applicant's overall proposal, in response to Parts (f) and (a) combined, acceptable because, during the period of extended operation, chemical treatments of cooling tower water will not contain chemical compounds that could cause cracking, pitting, or crevice corrosion on the external surfaces of the tanks. In addition, a one-time verification of deleterious compound fallout will be conducted by a soil sample to confirm the absence of an aggressive environment that could have been created before the period of extended operation. The staff's concern described in RAI B2.1.15-2, Parts (a) and (f), are resolved.

- Part (b): State whether the RWST insulation contains any harmful substances that could leach onto the tank surface.

  In its response dated August 6, 2012, the applicant stated that the tank is insulated with calcium silicate insulation that was manufactured and tested to comply with RG 1.36, "Nonmetallic Insulation for Austenitic Stainless Steel," Revision 0, February 1973. The insulation has low leachable chloride and fluoride concentrations and silicate.

  The staff finds the applicant's response acceptable because insulation that is manufactured and tested to the recommendations in RG 1.36 is known to have minimal potential to cause loss of material or cracking on stainless steel surfaces. The staff's concern described in RAI B2.1.15-2 Part (b) is resolved.

- Part (c): State whether and what portions of the CST are coated.

  In its response dated August 6, 2012, the applicant stated, "[t]he dome exterior of the CST is coated with a low halogen (<200 ppm) primer. The next layer of the CST dome is urethane foam insulation. The urethane foam insulation cover layer of the CST dome is an acrylic rubber sealant coating providing protection from UV radiation." The applicant also stated that the vertical exterior wall of the CST is not coated and it is insulated with FOAMGLAS® (glass dust) insulation.

  The staff finds the applicant's response acceptable because it described the configuration of the coating on the CST. Use of FOAMGLAS® (glass dust) insulation on vertical uncoated surfaces is acceptable because, based on the Material Safety Data Sheet for this insulation,

(http://www.industrialinsulation.com/images/foamglas_msds.pdf), it is composed of hydrogen sulfide, carbon monoxide, carbon dioxide, and glass dust, none of which are known to cause degradation of stainless steel materials. In addition, there is a low likelihood of water intrusion past the overlapping joints of the insulation jacketing. Furthermore, the vertical surfaces would shed this water, which would also make it unlikely that any corrosion would occur as a result of compounds leaching from the insulating materials. The response and staff evaluation of Part (d) of this RAI regarding the evaluation of the dome surface coating is discussed below. The staff's concern described in RAI B2.1.15-2, Part (c), is resolved.

- Part (d): State whether the external surface coating has been credited for license renewal and, if not, explain why the opportunistic inspections of the tank's external surface are adequate.

  In its response dated August 6, 2012, the applicant stated that the CST dome metallic surface primer does not have an intended function and is not credited as a preventive measure. It also stated that the CST acrylic rubber sealant is credited as a preventive measure for the CST urethane foam insulation and CST metallic surface.

  The staff noted that the applicant had not addressed why the proposed opportunistic inspections of the tank's external surfaces are adequate. However, the staff noted that the applicant addressed the external inspections in the response to Part (a) of this RAI. By letter dated July 5, 2012, the staff issued RAI B2.1.15-3, Part (a), associated with the "detection of aging effects" program element, requesting that the applicant state the basis for how an inspection conducted once within 5 years of entering the period of extended operation and whenever the tank is drained is sufficient to detect pitting, crevice corrosion, and cracking. In its response dated August 6, 2012, to RAI B2.1.15-3, Part (a), in part (see further aspects of the staff evaluation of this response below), the applicant stated:

  > Instead of inspecting the internal surface of the tank walls, only the external surface of the tank wall will be inspected. The inspection of the tank wall external surface prior to entering the period of extended operation will include locations where the insulation will be removed to demonstrate that the insulating materials are effective in preventing moisture intrusion to the tank surface. External wall surface inspection will require insulation to be removed on 25 locations on the tank external walls to allow inspection for loss of material and cracking. At least ten of the 25 locations will be near the base of the tank wall. Each location will measure approximately one square foot in area.

  The applicant also stated that the tank bottom internal surface will be examined by measuring thickness along 12-inch wide bands of the bottom. The staff noted that this response replaces the opportunistic inspection of the external surfaces of the tank with a one-time inspection. The staff finds the applicant's responses to RAI B2.1.15-2, Part (d) and RAI B2.1.15-3, Part (a), partially acceptable because a one-time inspection of 25 one-square-foot samples of the tank's external surfaces before entering the period of extended operation is an acceptable method to confirm that leakage through the acrylic rubber sealant coating does not occur, and external visual inspections conducted by the Aboveground Metallic Tanks Program could detect cracking or blistering in the acrylic rubber sealant during the period of extended operation. Based on the one-time inspection of the tanks surface and periodic visual examinations (conducted on a RFO

interval) of the acrylic rubber sealant coating, the staff finds that crediting the acrylic rubber sealant coating as a preventive measure is acceptable. However, it was not clear to the staff when in the time frame before the period of extended operation the one-time inspection will be conducted, whether the inspection locations will include the dome region, and how many bottom measurements will be obtained in each 12-inch band. In addition, the applicant did not include details on the inspections, including the number and size, in the program and FSAR supplement. By letter dated October 1, 2012, the staff issued RAI B2.1.15-2a requesting that the applicant state (a) the timing of the one-time inspection of the external surfaces of the tank, (b) whether and how many inspections will be conducted on the external metallic surfaces in the dome region, and (c) how many inspections will be conducted in each 12-inch band of the tank bottom. In addition, the staff requested that the applicant update its FSAR supplement to reflect the one-time inspection details for the dome and wall surfaces.

In its response dated October 31, 2012, the applicant stated that the timing of the one-time inspection will be within the 5-year period before entering the period of extended operation, and a minimum of 2 of the 25 inspection locations will be in the dome region. The applicant revised the tank bottom inspection to include a scanning technique (e.g., low-frequency electromagnetic technique) of the entire bottom of the tank that will be capable of detecting loss of material below nominal plate thickness. Any regions below nominal plate thickness will have a followup ultrasonic thickness reading. The applicant also stated that, if there are areas of significant loss of material, future ultrasonic thickness measurements and trending will be performed. The applicant amended the FSAR Supplement and program to reflect the response to this RAI.

The staff finds the applicant's response acceptable because:

- Conducting a one-time inspection within the 5-year period before the period of extended operation is consistent with GALL Report AMP XI.M32, "One-Time Inspection," which states that these inspections should be conducted no earlier than 10 years before the period of extended operation. Reasonable assurance that aging of the tank's surface is not occurring because of contaminants in the atmosphere is provided by the one-time inspections of the bare tank surfaces; the fact that the cooling tower water will not contain chemical compounds that could cause cracking, pitting, or crevice corrosion on the external surfaces of the tanks during the period of extended operation; and the one-time soil surface sample near the CST and RWST to confirm that chlorides or other aggressive cooling tower water treatment chemicals are not creating an aggressive environment.

- The tank's dome area will be sampled to ensure that aging is not occurring in this region. The inspections, coupled with the slope of the tank's roof resulting in any potential leakage through the insulation flowing to the ground and not remaining on the roof, provides reasonable assurance that aging of the tank's roof is not occurring because of contaminants in the atmosphere.

- The entire tank bottom will be scanned with a technique capable of detecting changes from nominal plate thickness, and followup ultrasonic examinations will be conducted at any locations where the wall thickness is below nominal. Given that the entire tank bottom is scanned, and local ultrasonic readings will be taken as necessary, this approach is consistent with GALL Report AMP XI.M29, "Aboveground Metallic Tanks."

- The example technique cited, LFET, has been conducted in the refinery business and was effectively demonstrated by a comparison of inspection test results against the internal inspection of a previously in-service refinery tank. As documented in "Detecting Corrosion in Production Tanks," DT Schardine, Inspection Trends, American Welding Society, summer 2008, the external LFET inspection results were consistent with the internal inspection. The nondestructive examination procedure, "Examination for the Detection and Sizing of Pitting, Corrosion, and Wall Loss Using Low Frequency Electromagnetic Techniques," TesTex document NPS-PROCOO7, Revision 4, September 2007, Section 2.2, states that the method is capable of inspecting ferritic and non-ferritic materials up to ¾ inch. Section 5.2.2.5 states that the technique can be used on flat bottom tanks, while Section 7.1.5 states that a frequency of 1000 hertz is used to inspect stainless steel materials. Therefore, there is reasonable assurance that a LFET, or a technique with equivalent capability, can be used as an effective screening tool.

The staff's concerns described in RAIs B2.1.15-2, Part (d); B2.1.15-3, Part (a); and B2.1.15-2a are resolved.

- RAI B2.1.15-2, Part (e): Given the evidence of water stains on the side of the CST where insulation is not installed, state the basis for why it can be concluded that the CST and RWST jacketing will prevent water intrusion into the tank insulation and then onto the tank surface.

  In its response dated August 6, 2012, the applicant stated that the water stains on the CST were caused by leakage from the CST pipehouse roof. The applicant also stated that the roof covering the CST pipehouse was replaced in 2011 to provide a better seal between the CST pipehouse and tank insulation, thus sheltering and protecting the uninsulated portion of the CST.

  The staff finds the applicant's response acceptable because the source of leakage was not through the jacketing, the leaking roof joint was repaired, and during the AMP audit, the staff's walkdown did not reveal any corrosion associated with the leakage. The staff's concern described in RAI B2.1.15-2, Part (e), is resolved.

The "detection of aging effects" program element in GALL Report AMP XI.M29 recommends that external surfaces of the tank be inspected on a refueling outage interval. However, during its audit, the staff noted that the applicant's Aboveground Metallic Tank Program states that visual inspections of the exterior surfaces of the CST and RWST are conducted when the surfaces are accessible. The program basis document also states that for inaccessible exterior tank surfaces, the applicant will sample wall thickness to ensure that the tank bottom and tank wall sections with insulated outer surfaces are not losing material or cracking. As noted above in the staff evaluation of RAI B2.1.15-3, Part (a), the applicant amended its program to include a one-time inspection of a sample of the CST's and the RWST's insulated outer surfaces in lieu of opportunistic inspections. The staff, however, also questioned how cracking will be detected. By letter dated July 5, 2012, the staff issued RAI B2.1.15-3, Part (b), requesting that the applicant state what inspection technique will be used to detect cracks.

In its response to RAI B2.1.15-3, Part (b), dated August 6, 2012, the applicant stated that cracking will be detected by a surface exam technique from the external surface after the insulation has been removed.

The staff finds the applicant's response acceptable because surface examination techniques are capable of detecting cracking in stainless steel. The staff's concern described in RAI B2.1.15-3, Part (b) is resolved.

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

Exception. LRA Section B2.1.15 states an exception to the "detection of aging effects" program element. In this exception, the applicant stated that, to determine the thickness of the tank bottom, UT thickness measurements of the bottom of each FWST from the internal surface will be performed at least once every 10 years. Thickness measurement inspections may occur more frequently based on the results of visual inspections. The staff noted that the GALL Report recommends that bottom thickness measurements be performed within 5 years of entering the period of extended operation and whenever the tank is drained. The staff reviewed this exception against the corresponding program element in GALL Report AMP XI.M29 and finds it acceptable because (a) the bottom thickness measurement conducted within 5 years of entering the period of extended operation will be evaluated in light of the acceptance criteria in the program; (b) based upon the degree of conformance with the acceptance criteria, additional thickness measurements will be implemented if necessary; and (c) the thickness measurements conducted every 10 years will be augmented by visual inspection results conducted every time the tank is drained and, therefore, these inspections will be sufficient to provide reasonable assurance that each tank will meet its intended function(s).

Based on its audit and review of the applicant's responses to RAIs B2.1.15-1, B2.1.15-2, B2.1.15-2a, and B2.1.15-3, 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.M29. The staff also reviewed the exception associated with the "detection of aging effects" program element and its justification and finds that the AMP, with the exception, is adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.15, as amended by letter dated April 25, 2012, summarizes operating experience related to the Aboveground Metallic Tanks Program. The applicant stated that a 2007 internal inspection of the B FWST identified small amounts of corrosion and mineral deposits. A followup inspection in 2009 identified several areas of blistering in the coating and calcium deposits, along with minor corrosion on bare metal surfaces. A subsequent inspection of B FWST in 2011 revealed little-to-no degradation of the internal metallic surfaces of the tank; however, there was some surface roughness and pitting. In addition, general blistering and delamination of the coating was found. In 2008 an internal inspection of A FWST also identified minor blistering and limestone deposits. A followup inspection in 2010 identified discontinuities and delamination sites in the coating in addition to some pitting. The applicant also stated given that the cathodic protection system was determined to be effective, the tank interiors would not degrade excessively before the next planned inspection.

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 Aboveground Metallic Tanks Program, LRA Section B2.1.15, and the staff's independent review of CARs and work orders indicate that multiple inspections of the internal surfaces of the FWSTs, spanning 2007 through 2011, have revealed blistering and delamination of coatings. Work orders documented that these defects were not all repaired before returning the tanks to service. The work orders also documented that the acceptance of the as-found defects that were not repaired was based on internal cathodic protection of the tank preventing corrosion of exposed metal surfaces. The staff noted that neither the LRA AMP nor FSAR supplement state that the cathodic protection system is credited as a preventive measure to account for the plant-specific operating experience. In addition, the staff lacks sufficient information to conclude that the delamination of the coatings would not block downstream components either based on current levels of delamination or those that could occur in the period of extended operation. By letter dated July 5, 2012, the staff issued RAI B2.1.15-4 requesting that the applicant: (a) state the basis for why blistering and delamination of coatings will not occur during the period of extended operation despite the current trend of plant-specific operating experience, or revise the program and LRA Section A1.15, FSAR Supplement to credit the FWST internal cathodic protection system as a preventive measure to prevent corrosion on exposed bare metal as-left surfaces of the tanks or, alternatively, (b) state the basis for why delamination of coatings will not prevent downstream in-scope components from being able to perform their intended function(s), including consideration of the size of delaminations that could occur during the period of extended operation.

In its response dated August 6, 2012, the applicant stated that the blistering and delamination will be corrected before the period of extended operation through the application of a new coating. The FWST internal cathodic protection system will prevent corrosion on the internal surfaces of the tank. LRA Sections A1.15 and B2.1.15 were revised to state that cathodic protection is used as a preventive measure to prevent corrosion on exposed bare metal as-left surfaces of the tanks. The applicant also stated that coating delaminations have been minor and that they will be removed before the period of extended operation during the recoating of the tanks' internal surfaces. The applicant further stated that the tank outlets consist of a 14-inch pipe that extends 3 feet inside the tank and ends in a 90 degree radius elbow turned downward, ending 6 in. above the bottom of the tank; therefore, in the event of delamination, this geometry would preclude any large pieces of coating from entering the outlet of the tank and affecting downstream equipment.

The staff finds the applicant's response acceptable, in part, because the cathodic protection system will prevent corrosion on exposed metal surfaces of the tank. While the staff understands that the coatings will be replaced before the period of extended operation, given past plant-specific operating experience, subsequent delamination of coatings could occur. Neither the Fire Water System, nor Aboveground Metallic Tanks Programs nor the corresponding FSAR supplements state that the FWSTs will be cleaned and inspected on an alternating refueling outage frequency and, therefore, the staff cannot determine if followup inspections of the new coatings will occur to confirm the lack of delamination. The Callaway Site Addendum to FSAR Section 9.5.1.2.1 states, "[t]he FPS water supply is separated from all other site water supply systems and is based on providing 2,300 gallons per minute of water for 2 hours to sprinkler systems with a simultaneous total flow of 1,000 gallons per minute to hose stations." The staff noted that the fluid velocity corresponding to 3,300 gpm in a 14-inch pipe is approximately 7.8 feet per second. Even considering the 6-inch clearance to the bottom of the

tank, delaminated particles could still be carried into the flow stream. The staff lacked sufficient information to find that downstream components will not be affected by delaminated coatings. By letter dated October 1, 2012, the staff issued RAI B2.1.15-4a requesting that the applicant revise the Fire Water System or Aboveground Metallic Tanks Program, and the corresponding FSAR supplement, to state the frequency of coating inspections conducted to confirm that delamination of the coatings does not occur or provide the basis for why the smallest size delaminated particle that could prevent an in-scope intended function from being performed will not be transported from the tank.

In its response dated October 31, 2012, the applicant revised LRA Sections A1.14 and B2.1.14 to include internal coating inspections on the fire water storage tanks with a minimum frequency of alternating refueling outages.

The staff finds the applicant's response acceptable because new coatings will be installed on the tanks before the period of extended operation and, between the two fire water storage tanks, a tank will be inspected, on average, every refueling outage interval, which is sufficient to detect coating degradation before impacting the intended functions of the fire water storage tanks or downstream components. The staff's concern described in RAI B2.1.15-4a is resolved.

During its review of the applicant's LRA, the staff identified several instances of industry operating experience associated with age-related degradation of tanks. Tanks with defects variously described as wall thinning, pinhole leaks, cracking, and through-wall flaws had been identified by detecting external leakage rather than through internal inspections. As a result, the staff issued LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," (ADAMS Accession No. ML13227A361) to address this operating experience. GALL Report AMP XI.M29 was revised to (a) manage aging effects for both internal and external surfaces of tanks, (b) include cracking as an applicable aging effect for certain material and environment combinations, (c) provide a table of inspection techniques and frequencies, and (d) extend the scope of the AMP to indoor welded tanks that have a large volume (greater than 100,000 gallons), are designed to near-atmospheric internal pressures, sit on concrete, and are exposed internally to water. By letter dated October 7, 2013, the staff issued RAI 3.0.3-4, requesting that the applicant either describe how its program already addresses the issues identified in this revised guidance or provide adequate justification why its program does not need to address them.

In its response dated December 20, 2013, the applicant stated that it does not have any indoor welded tanks that meet the scoping criteria in revised GALL Report AMP XI.M29. The applicant also stated that it will manage the aging of fire water storage tanks with the Fire Water System Program, rather than the Aboveground Metallic Tanks Program. For outdoor tanks, the applicant revised its Aboveground Metallic Tanks Program and FSAR supplement to be consistent with the new inspection recommendations. The staff noted that the applicant's revised program includes a one-time inspection of a representative sample of tank external surfaces (after insulation removal) and a one-time volumetric examination of tank bottoms. The applicant supported the use of one-time inspections by stating that the chemical treatments of the cooling tower water do not contain aggressive compounds and that non-corrosive conditions will be verified every 10 years by testing of the soil and tank surface residues.

The staff finds the applicant's response acceptable because the applicant incorporated the new inspection guidance provided in LR-ISG-2012-02, such that the Aboveground Metallic Tanks Program is consistent with the revised GALL Report AMP XI.M29. The staff noted that the applicant's use of one-time inspections for the tank external surfaces and bottoms in lieu of

periodic inspections is allowed by LR-ISG-2012-02. Table 4a of the revised GALL Report AMP XI.M29 states that one-time inspections can be used in the absence of sources of chloride in the vicinity of the plant and if evaluations of the soil and tank surface residues are performed prior to the period of extended operation and every 10 years to demonstrate the absence of aggressive environments. Also, the staff noted that managing the aging effects of fire water storage tanks with the Fire Water System Program is consistent with the revised staff guidance in LR-ISG-2012-02. The staff's evaluation of the Fire Water System program is documented in SER Section 3.0.3.2.7. The staff's concern described in RAI 3.0.3-4 is resolved.

Based on its audit, review of the application, and review of the applicant's responses to RAI B2.1.15-4, RAI B2.1.15-4a, and RAI 3.0.3-4, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. The staff also finds that the operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking corrective actions.

FSAR Supplement. LRA Section A1.15, as amended by letters dated April 25, 2012, August 6, 2012, October 31, 2012, February 28, 2013, and December 20, 2013, provides the FSAR supplement for the Aboveground Metallic Tanks Program. The staff reviewed this FSAR 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. 11) to implement the new Aboveground Metallic Tanks Program within the 5-year period before the period of extended operation for managing aging of applicable components.

The staff finds that the information in the FSAR supplement, as amended by letters dated April 25, 2012, August 6, 2012, October 31, 2012, February 28, 2013, and December 20, 2013, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Aboveground Metallic Tanks 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.M29. 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 FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.9 Fuel Oil Chemistry

Summary of Technical Information in the Application. LRA Section B2.1.16 describes the existing Fuel Oil Chemistry Program as consistent, with enhancements, with GALL Report AMP XI.M30, "Fuel Oil Chemistry." The LRA states that the Fuel Oil Chemistry Program manages loss of material on the internal surface of components in the emergency diesel engine fuel oil storage and transfer system, fire protection system, standby diesel generator engine system, and emergency operations facility and technical support center diesels security building system. The LRA also states that the program includes the following:

- surveillance and monitoring procedures for maintaining fuel oil quality by controlling contaminants in accordance with plant technical specifications and ASTM Standards D1796-83 and D2276-78
- periodic draining of the emergency fuel oil system storage tanks and day tanks

- cleaning and visual inspection of internal surfaces of the emergency fuel oil system storage tanks and day tanks during periodic draining
- ultrasonic measurements of the emergency fuel oil system storage tank and fuel oil day tank bottom thickness if there are indications of reduced cross-sectional thickness found during the visual inspection
- periodic volumetric examination of the tank bottom, from the external surface, of the diesel fire pump fuel oil day tank and security diesel generator fuel oil day tank where tank design prevents cleaning and inspection from the inside
- inspection of new fuel oil before introduction to storage tanks

The staff noted that the LRA references ASTM Standards D1796-83 and D2276-78, whereas GALL Report AMP XI.M30 references ASTM Standards D1796-97 and D2276-00. The staff has reviewed all four revisions of the ASTM Standards and finds that there are no technical differences between the revisions that warrant the need for additional information from the applicant.

Based on recent staff reviews of several LRAs and of industry OE, the staff has determined that additional recommendations beyond those in the GALL Report should be considered in regards to managing loss of coating integrity for internal coatings of piping, piping components, heat exchangers, and tanks. By letters dated October 7, 2013, and March 25, 2014, the staff issued RAI 3.0.3-2 and RAI 3.0.3-2a, respectively, to address loss of coating integrity. In its response dated April 23, 2014, the applicant revised the Fuel Oil Chemistry program to address loss of coating integrity for the emergency fuel oil storage tanks and day tanks. The staff's evaluation of the applicant's response to RAI 3.0.3-2 and RAI 3.0.3-2a is documented in SER Section 3.0.3.4. The staff's evaluation of changes to LRA Sections B2.1.16 and A1.16, and Commitment No. 12 to address loss of coating integrity follows.

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. For the "scope of program," 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," and "detection of aging effects" program elements in GALL Report AMP XI.M30 recommend that periodic cleaning of diesel fuel oil tanks should be performed to remove sediments. However, during its audit, the staff found that the applicant's Fuel Oil Chemistry Program does not state that periodic cleaning of the diesel generator fire pump fuel oil day tank and the security diesel generator fuel oil day tank will be performed. By letter dated July 5, 2012, the staff issued RAI B2.1.16-1 requesting that the applicant state how the volumetric examination, which will be conducted every 10 years, will be sufficient to ensure that the intended function of the tanks will be maintained in lieu of not performing periodic tank cleanings that will mitigate any corrosion that may occur. Alternatively, the staff requested the applicant to describe the actions that it will perform to prevent or mitigate corrosion of the diesel generator fire pump fuel oil day tank and the security diesel generator fuel oil day tank and the basis for how these actions will be effective.

In its response dated August 6, 2012, the applicant stated that because of the limited access to the diesel generator fire pump fuel oil day tank and the security diesel generator fuel oil day tank, draining and cleaning the tanks is not physically possible. The applicant stated that water will be periodically removed from the bottom of these tanks, minimizing the exposure of internal

tank surfaces to the water, which will reduce the likelihood of corrosion and eliminate the environment for microbiological organisms. The applicant also stated that the tanks will be periodically sampled to determine water and sediment, particulate, and microbial activity concentrations to ensure that corrosion is not taking place. The applicant further stated that should periodic tests indicate the presence of biological activity, a biocide will be added to the tanks. The applicant stated that fuel oil receipt sampling will be performed for water and sediment before introduction of the new fuel oil into the tanks. The applicant also stated that volumetric examinations will identify any loss of material associated with corrosion and, if such a loss of material is discovered, it will be addressed by the CAP.

The staff finds the applicant's response acceptable because:

- Conducting tank wall thickness measurements every 10 years is sufficient to detect potential corrosion and this is consistent with the "detection of aging effects" program element of GALL Report AMP XI.M30 which states that these measurements are conducted when visual examination is not possible or if visual examinations detect evidence of degradation.
- The first wall thickness inspection will be conducted within the 10-year period prior to the period of extended operation and this test will be capable of detecting any internal corrosion prior to entering the period of extended operation.
- Any loss of material will be evaluated by the applicant's CAP.
- Fuel oil quality is maintained by monitoring and controlling fuel oil contamination in accordance with the Callaway TSs and, therefore, the inventory source for these tanks should be free of water, sediment, and biological activity.
- The applicant will periodically drain any accumulated water in the diesel generator fire pump fuel oil day tank and the security diesel generator fuel oil day tank, along with sampling new fuel oil before it is placed in the tanks.
- The applicant will perform periodic sampling of the tanks to ensure that corrosion of the internal surfaces of the tanks is not taking place.
- The addition of biocide to a tank that shows signs of biological activity will further provide reasonable assurance that internal corrosion of the tanks will not take place.

The staff finds that these actions will provide reasonable assurance that corrosion and microbiological corrosion is not taking place. Therefore, the staff's concern described in RAI B2.1.16-1 is resolved.

The staff also reviewed the portions of the "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," 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 B2.1.16 states an enhancement to the "preventive actions" program element. In this enhancement, the applicant stated that procedures will be enhanced to include periodic draining of the water from the bottom of the emergency fuel oil system day tanks, diesel fire pump fuel oil day tanks, and security diesel generator fuel oil day tank. The applicant also stated that procedures will be enhanced to add biocide to the diesel fire pump fuel oil day tank and security diesel generator fuel oil day tank if periodic testing indicates biological activity or evidence of corrosion. 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 existing Fuel Oil Chemistry Program consistent with the GALL Report AMP which recommends that biocides or corrosion inhibitors may be added (1) as a preventive measure or (2) if periodic testing indicates biological activity or evidence of corrosion and periodic draining of water collected at the bottom of a tank.

Enhancement 2. LRA Section B2.1.16 states an enhancement to the "preventive actions," and "detection of aging effects" program elements. In this enhancement, the applicant stated that procedures will be enhanced to include draining, cleaning, and inspection of the emergency fuel oil system day tanks within the 10-year period before the period of extended operation and at least once every 10 years after entering the period of extended operation. 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 existing Fuel Oil Chemistry Program consistent with the GALL Report AMP which recommends that these activities (i.e., draining, cleaning, and inspection) be conducted.

Enhancement 3. LRA Section B2.1.16 states an enhancement to the "parameters monitored or inspected" program element. In this enhancement, the applicant stated that procedures will be enhanced to include a determination of water and sediment in the periodic sampling of the emergency fuel oil system day tanks and security diesel generator fuel oil day tank. Additionally, the applicant stated that procedures will be enhanced to include a determination of particulate concentrations in the periodic sampling of the emergency fuel oil system day tanks, diesel fire pump fuel oil day tanks, and security diesel generator fuel oil day tank. The applicant also stated that procedures will be enhanced to include a determination of microbial activity concentrations in the periodic sampling of the emergency fuel oil system storage tanks, emergency fuel oil system day tanks, diesel fire pump fuel oil day tanks, and security diesel generator fuel oil day tank. Finally, the applicant stated that procedures will be enhanced to include new fuel oil receipt sampling for water and sediment before introduction into the security diesel generator fuel oil day tank and diesel fire pump fuel oil day tank. 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 existing Fuel Oil Chemistry Program consistent with the GALL Report AMP which recommends that the AMP monitor fuel oil quality through receipt testing and periodic sampling of stored fuel oil.

Enhancement 4. LRA Section B2.1.16 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that procedures will be enhanced to perform a volumetric examination of the emergency fuel oil system storage tanks and day tanks after evidence of tank degradation is observed during the visual inspection within the 10-year period before the period of extended operation and at least once every 10 years after entering the period of extended operation. Additionally, the applicant stated that procedures will be enhanced to perform a volumetric examination on the external surface of the diesel fire pump fuel oil day tanks and security diesel generator fuel oil day tank within the 10-year period before the period of extended operation and at least once every 10 years after entering the period of extended operation. 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 existing Fuel Oil Chemistry Program consistent with the GALL Report AMP which recommends the same inspections and frequency for inspections.

Enhancement 5. LRA Section B2.1.16 states an enhancement to the "monitoring and trending" program element. In this enhancement, the applicant stated that procedures will be enhanced to include at least quarterly trending for water, biological activity, and particulate concentrations

on the emergency fuel oil system day tanks, diesel fire pump fuel oil day tanks, and security diesel generator fuel oil day tank. 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 existing Fuel Oil Chemistry Program consistent with the GALL Report AMP which recommends monitoring and trending of the same parameters.

Enhancement 6. LRA Section B2.1.16 states an enhancement to the "corrective actions" program element. In this enhancement, the applicant stated that procedures will be enhanced to include immediate removal of accumulated water when discovered in the emergency fuel oil system day tank, diesel fire pump fuel oil day tank, and security diesel generator fuel oil day tank. 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 existing Fuel Oil Chemistry Program consistent with the GALL Report AMP which recommends immediate removal of any accumulated water found in a fuel oil storage tank.

Enhancement 7. As amended by letter dated April 23, 2014, LRA Section B2.1.16 contains an enhancement to the "preventive actions," "parameters monitored or inspected," "detection of aging effect," "monitoring and trending," and "acceptance criteria" program elements. In this enhancement, the applicant provided a list of procedure enhancements associated with coatings inspections (e.g., base line inspections, extent of inspections), training and qualification of individuals involved in coating inspections, acceptance criteria, and corrective actions. These enhancements and the corresponding staff evaluation are documented in the response to RAI 3.0.3-2a Request Nos. (2), (5), and (6) in SER Section 3.0.3.4.

Based on its audit of the applicant's Fuel Oil Chemistry Program and review of the applicant's response to RAI B2.1.16-1, 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.M30. In addition, based on its review of the applicant's responses to RAIs 3.0.3-2 and 3.0.3-2a, the staff finds that the applicant's program changes to address loss of coating integrity are consistent with recommended measures acceptable to the staff for addressing loss of coating integrity for internal coatings as described in SER Section 3.0.3.4. In addition, the staff reviewed the enhancement(s) associated with the "preventive actions," "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 B2.1.16 summarizes operating experience related to the Fuel Oil Chemistry Program. The LRA states that in 2009, the applicant performed a diesel fuel oil program self-assessment and made the following changes as a result of the assessment findings:

> (a) [t]he Certificate of Compliance for incoming diesel fuel oil truck loads was updated to include assurances that no biodiesel is present[;] [and] (b) the diesel fuel oil testing program procedure was changed to include [preventative maintenance] PMs for sampling of both underground storage tanks after each outage, including specific gravity, density, lubricity, and microbial activity.

The LRA also states that in 2010, in response to industry operating experience concerning contamination of diesel fuel oil with biodiesel, the applicant took the following actions to ensure that biodiesel is not used:

> (a) a procedure that tests for biodiesel was created; (b) both diesel fuel oil storage tanks were sampled for biodiesel and were confirmed to have less than minimum detectable; (c) testing for biodiesel was added to the required analyses for truck receipt sampling; [and] (d) PMs were created to sample the fuel oil storage tanks after the 24-hour diesel runs at the end of each outage.

The LRA further states the following:

> During [RFO] 17 (spring 2010), as part of the 10-year cleaning and inspection of the emergency fuel oil system storage tank TJE01A, the condition of the internal coating was inspected and determined to be in acceptable condition. No debris, sludge, or bare metal areas were identified during the inspection. The coal tar epoxy coating was in good condition; however, coating blisters were identified in various places. An engineering evaluation determined the identified blistering was acceptable since all instances were less than nickel size. No issue with the coatings has been documented in any of the previous inspections. The procedure requiring the condition of each tank coating to be documented was enhanced to require inclusion of pictures of the internal coating condition and additional details regarding tank internal coating cleanliness, coating color, coating uniformity, and general tank condition.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant. 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.

Given that the engineering evaluation described in the operating experience for tank TJE01A in spring 2010 did not state the potential corrosion rate if the blisters were to open up, it was not clear to the staff that the tank would be capable of performing its intended function(s) should further degradation of the coating occur between inspections. By letter dated July 5, 2012, the staff issued RAI B2.1.16-2 requesting that the applicant provide an evaluation of the corrosion rate and minimum design wall thickness of the fuel oil system storage tank should one of the blisters open up, exposing the fuel oil in the tank to the bare metal material of the tank. Additionally, the staff requested the applicant to provide an evaluation of the adequacy of the 10-year inspection interval based on the evaluation of the corrosion rate.

In its response dated August 6, 2012, the applicant stated the following:

> Using the [National Association of Corrosion Engineers] NACE Standard RP0502-2002 default corrosion rate of 16 [mils per year] mpy over the 10–year interval, as a bounding scenario, only 0.16 inches of wall thickness would be lost. Using a minimum plate thickness of 0.875 inches, this would result in a final thickness of 0.715 inches, which is significantly greater than the minimum requirements of 0.1159 inches for the shell and 0.2771 inches for the head.
>
> There has been no plant operating experience regarding water found in the emergency diesel fuel oil storage tank. This record of good chemistry control, plus the preventive measure of adding a biocide to the fuel oil, ensures that even

if there was a failure of the internal coating, the environment needed for corrosion to occur would not exist. If the monthly fuel oil sampling results start to indicate a trend of water or corrosion products found in the oil, the applicant stated that additional corrective actions would be evaluated.

The staff noted that the basis for the National Association of Corrosion Engineers (NACE) RP0502-2002 corrosion rate of 16 mils per year (mpy) is an upper 80 percent confidence level of maximum pitting rates for long-term (up to 17-year duration) underground corrosion tests of bare steel pipe coupons without cathodic protection in a variety of soils, including native and nonnative backfill. The staff also noted that given the configuration of a limited area being exposed to corrosion, the pitting rate could be higher. In contrast, the internal environment of the tank is in all likelihood less conducive to corrosion than that of a soil environment. Based on a NACE 2006 Paper, "In Support of Direct Assessment Reassessment Intervals," Table 2, "Uhlig's Corrosion Rate for Steel in Soil According to Soil Resistivity and Drainage," average pitting corrosion rates in steel pipe buried in low resistivity and poor drainage soils is 5.5 mpy. Although not directly comparable to the environment in the fuel oil storage tank, higher corrosion rates would not be anticipated given the testing for contaminants that the applicant conducted. Applying this pitting corrosion rate to the applicant's design data demonstrates sufficient margin to conclude that the intended function(s) of the tank will continue to be met between inspections.

The staff finds the applicant's response acceptable because the applicant has shown that there is sufficient margin over a 10-year period to provide reasonable assurance that any corrosion occurring due to fuel oil being exposed to the bare metal internal surface of the emergency diesel fuel oil storage tank would not challenge the minimum requirements for the tank. Furthermore, the preventive measures listed by the applicant will further mitigate the chance of corrosion to less than what would be expected for buried steel material. In addition, the periodic sampling of the tank to check for corrosion will allow the applicant to take corrective actions should any corrosion exist. Therefore, the staff's concern described in RAI B2.1.16-2 is resolved.

On January 22, 2013, the staff held a telephone conference call with the applicant regarding a revision to Commitment No. 12 provided by LRA Amendment 14 dated October 31, 2012. In its revision to Commitment No. 12, the applicant stated that the blisters in the coating of the train A EDG fuel oil storage tank were to be scraped off and the bare metal inspected before the period of extended operation. The staff noted that, in the commitment revision, the applicant did not indicate whether the blistered areas would be repaired after they were scraped and inspected. During the telephone conference call, the staff stated that it had concerns over whether the removal of the blisters, without subsequent repair, could potentially weaken the integrity of the remaining coating and could lead to coating debris entering into the fuel oil and subsequently becoming a debris source that could impact the safety function of the EDG. The applicant stated during the telephone conference call that the intention was to repair the coating after the blisters were removed. Therefore, by letter dated January 24, 2013, the applicant provided LRA Amendment 20 which revised Commitment No. 12 to state that the coating would be repaired after inspection and before the period of extended operation. By letter dated February 28, 2013, the applicant provided LRA Amendment 22 which revised Commitment No.12 to state that the coating will be repaired after inspection and six months before the period of extended operation or by the end of Callaway's last RFO before the period of extended operation, whichever occurs later. The staff finds this acceptable because repairing the coating will provide reasonable assurance that the remaining coating will not become a debris source. The staff's concern regarding Commitment No. 12 is resolved.

Based on its audit and review of the application and a review of RAI B2.1.16-2, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.M30 was evaluated.

FSAR Supplement. LRA Section A1.16 provides the FSAR supplement for the Fuel Oil Chemistry Program. The staff reviewed this FSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff noted that the applicant committed (Commitment No. 12) to implement the enhancements to the program six months before the period of extended operation for managing aging of applicable components during the period of extended operation. The staff also noted that the applicant committed (Commitment No. 12) to scraping, inspecting for aging, and repairing the blisters in the train A emergency diesel generator fuel oil storage tank six months prior to the period of extended operation or by the end of the last RFO before the period of extended operation, whichever occurs later.

The staff noted that the applicant modified LRA Section A.1.16 in response to RAI 3.0.3-2 and RAI 3.0.3-2a by letter dated April 23, 2014, to address loss of coating integrity. The staff also noted that the applicant committed (Commitment No. 12) to revise the Fuel Oil Chemistry Program procedures to address loss of coating integrity as described above in Enhancement No. 7.

The staff finds that the information in the FSAR supplement, as amended by letters dated January 24, 2013, February 28, 2013, and April 23, 2014, is an adequate summary description of the program. The staff noted that the applicant's FSAR-SP states that ASTM Standards D4057 and D975 also will be used to administer the Fuel Oil Chemistry Program. The staff finds this acceptable because the GALL Report AMP XI.M30 references these standards as examples of acceptable standards for use.

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. Also the staff reviewed the enhancements and confirmed that their implementation through Commitment No. 12 six months before 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 FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.10 Reactor Vessel Surveillance

Summary of Technical Information in the Application. LRA Section B2.1.17, as amended by letters dated June 5, 2012, and October 31, 2012, describes the existing Reactor Vessel Surveillance Program as consistent, with enhancements, with GALL Report AMP XI.M31, "Reactor Vessel Surveillance." The LRA states that the AMP manages loss of fracture toughness for reactor vessel beltline materials exposed to reactor coolant and neutron flux in accordance with the requirements of 10 CFR Part 50, Appendix H, and ASTM E 185-82, "Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels." The LRA also states that surveillance capsule test results are used to

demonstrate compliance with the Charpy upper-shelf energy (USE) requirements of 10 CFR Part 50, Appendix G, and the pressurized thermal shock (PTS) requirements of 10 CFR 50.61; and they are also used to revise pressure-temperature (P-T) limit curves and project the end-of-license neutron fluence. In accordance with the LRA, the last-tested surveillance capsule removed from the reactor vessel was exposed to neutron fluence equivalent to about 54 effective full power years (EFPY), which slightly exceeds the 60-year peak reactor vessel wall neutron fluence. The LRA further states that one of the two standby capsules was removed at 71 EFPY of equivalent exposure and is stored in the spent fuel pool for reinsertion into the reactor vessel or testing as deemed appropriate. The other standby capsule will be removed at approximately 108 EFPY of equivalent exposure, consistent with ASTM E 185-82, which states that capsules may be removed from the reactor vessel when the capsule neutron fluence is between one and two times the peak fluence calculated for the reactor vessel at the end of operating life. In addition, the LRA states that changes to the capsule withdrawal schedule will be submitted to the staff for approval, as appropriate.

Staff Evaluation. During its audit, the staff reviewed the applicant's statement 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.M31. 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.M31 recommends that the Reactor Vessel Surveillance Program have at least one capsule with a projected neutron fluence equal to or exceeding the 60-year peak reactor vessel wall neutron fluence before the end of the period of extended operation. This program element also recommends that the program includes withdrawal of one capsule at an outage in which the capsule receives a neutron fluence of between one and two times the peak reactor vessel wall neutron fluence at the end of the period of extended operation and includes testing of the capsule in accordance with the requirements of ASTM E 185-82. During its audit, the staff noted that the applicant's program was not specific about whether the last surveillance capsule tested under this program would meet the above criterion for adequate aging management for 60 years of plant operation. Therefore, by letter dated June 22, 2012, the staff issued RAI B2.1.17-1 requesting that the applicant identify the neutron fluence (E greater than 1.0 MeV) for this capsule, as determined from the capsule dosimetry analysis.

In its response dated July 20, 2012, the applicant stated that "Capsule X" was the last surveillance capsule that was tested, and the capsule was exposed to a neutron fluence of 3.33×10^{19} n/cm^2 (E greater than 1.0 MeV), based on the neutron fluence calculated in WCAP-15400-NP, "Analysis of Capsule X from The Ameren-UE Callaway Unit 1 Reactor Vessel Surveillance Program," dated June 2000. The applicant also stated that the program description section and operating experience section of LRA Section B2.1.17 were revised as described in LRA Amendment 3, dated June 5, 2012, to identify the neutron fluence for "Capsule X."

The staff finds the applicant's response acceptable because the applicant provided the information necessary for the staff to confirm that the applicant's surveillance program is consistent with the "detection of aging effects" program element, which states that the program have at least one capsule with a projected neutron fluence equal to or exceeding the 60-year peak reactor vessel wall neutron fluence before the end of the period of extended operation. Specifically, the staff confirmed that "Capsule X," which was the last capsule tested, was exposed to a neutron fluence of 3.33×10^{19} n/cm^2 (E greater than 1.0 MeV). The staff also

confirmed that this capsule fluence exceeds the projected 60-year peak reactor vessel wall neutron fluence of 2.94 x 10^{19} n/cm^2 (E greater than 1.0 MeV) described in LRA Section 4.2.1, consistent with the GALL Report. The staff finds that LRA Section B2.1.17 was appropriately revised by LRA Amendment 3, dated June 5, 2012, to identify the neutron fluence for "Capsule X." The staff's concern described in RAI B2.1.17-1 is resolved.

Based on its review of the applicant's response to RAI B.2.17-1, the staff finds that the surveillance capsule withdrawal schedule criteria of ASTM E 185-82 is satisfied for 60 years of plant operation by the withdrawal and testing of "Capsule X," as documented in WCAP-15400-NP.

The staff noted that the remaining two surveillance capsules are designated as "standby" capsules in LRA Section B2.1.17. By letter dated June 22, 2012, the staff issued RAI B2.1.17-2 requesting that the applicant identify these standby surveillance capsules. In its response dated July 20, 2012, the applicant stated that the standby surveillance capsules are "Capsule W" and "Capsule Z." The applicant clarified that "Capsule Z" was previously removed from the reactor vessel at 71 EFPY of equivalent reactor vessel exposure and is currently stored in the spent fuel pool for reinsertion into the reactor vessel or future testing. The applicant also stated that "Capsule W" will be removed at approximately 108 EFPY of equivalent reactor vessel exposure. The applicant further stated that LRA Section B2.1.17 was revised by LRA Amendment 3, dated June 5, 2012, to identify these standby surveillance capsules.

The staff finds the applicant's response acceptable because the applicant amended LRA Section B2.1.17 to specifically identify the two standby surveillance capsules. The staff finds that the maintenance of these two standby capsules satisfies the recommendation of the "detection of aging effects" program element in GALL Report AMP XI.M31, which states that the program should retain additional capsules within the reactor vessel to support additional testing, as needed. The staff's concern described in RAI B2.1.17-2 is resolved.

The staff also reviewed the portions of the "detection of aging effects" and "monitoring and trending" 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 B2.1.17 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that following withdrawal of the final capsule, RV neutron fluence will be determined by ex-vessel dosimetry. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M31 and finds that the applicant's proposal to use ex-vessel dosimetry for monitoring neutron fluence following withdrawal of the final capsule will provide appropriate supplemental neutron fluence data and is, therefore, acceptable. As part of this enhancement, the applicant also stated that the testing specification will be enhanced to require that pulled and tested surveillance capsules are placed in storage for future reconstitution or reinsertion unless given NRC approval to discard. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M31 and finds it acceptable because when it is implemented it will ensure that any standby capsules tested in the future will be appropriately stored for future reconstitution and reinsertion, as needed, consistent with the recommendation of the "detection of aging effects" program element.

Enhancement 2. LRA Section B2.1.17 states an enhancement to the "monitoring and trending" program element. In this enhancement, the applicant stated that procedures will be enhanced to specifically require the evaluation of the impact of plant operation changes on the extent of

RV embrittlement. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M31 and finds it acceptable because when it is implemented it will ensure that the applicant's program is consistent with the recommendation of the "monitoring and trending" program element, which states that if future plant operations exceed RV embrittlement limitations or bounds, such as operating at a lower cold-leg temperature or higher fluence, the impact of plant operation changes on the extent of RV embrittlement is evaluated.

Based on its audit of the applicant's Reactor Vessel Surveillance Program and review of the applicant's responses to RAIs B2.1.17-1 and B2.1.17-2, 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.M31. In addition, the staff reviewed the enhancements associated with the "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 B2.1.17, as amended by letter dated June 5, 2012, summarizes operating experience related to the Reactor Vessel Surveillance Program. As an example of how the Reactor Vessel Surveillance Program will be effective in providing sufficient material data and dosimetry to monitor irradiation embrittlement during the period of extended operation, the applicant identified that (1) the last-tested capsule (Capsule X) specimens were exposed to a neutron fluence equivalent to approximately 54 EFPY and (2) the specimen test results satisfy the Charpy USE acceptance criterion of 10 CFR Part 50, Appendix G and the PTS screening criteria of 10 CFR 50.61. The applicant also noted that the specimen test results demonstrate that adjusted nil-ductility reference temperatures based on the surveillance data are less than those used in the calculation of the P-T limit curves, thereby demonstrating margin in the operating limits.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the audit report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately 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 that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.M31 was evaluated.

FSAR Supplement. LRA Section A1.17 provides the FSAR supplement for the Reactor Vessel Surveillance Program. The staff reviewed this FSAR 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 several inconsistencies between the two descriptions.

The staff noted that SRP-LR Table 3.0-1 recommends that the FSAR supplement provide that (1) any future tests of surveillance capsules will meet the requirements of ASTM E 185-82, (2) any changes to the capsule withdrawal schedule will be submitted to the NRC for approval,

and (3) untested capsules placed in storage will be maintained for future reinsertion. The staff noted that these attributes of the program have been adequately described in LRA Section B2.1.17; however, they are not specifically addressed in the Reactor Vessel Surveillance Program FSAR supplement (LRA Section A1.17).

By letter dated October 3, 2012, the staff issued RAI A1.17-1 requesting that the applicant revise the FSAR supplement for this program so that it is consistent with the recommended description for this program in SRP-LR Table 3.0-1. In its response dated October 31, 2012, the applicant stated that LRA Section A1.17 has been revised under LRA Amendment 14 to address the three SRP-LR Table 3.0-1 program attributes listed above. LRA Amendment 14 revisions to LRA Section A1.17 were provided as part of the applicant October 31, 2012, RAI response. The staff reviewed these revisions and determined that LRA Section A1.17, as revised, adequately describes the three program attributes listed above and is therefore consistent with the recommended FSAR supplement description for this program provided in SRP-LR Table 3.0-1. Therefore, the staff finds that RAI A1.17-1 is resolved.

The staff also noted that through LRA Table A4-1, "License Renewal Commitments," the applicant committed (Commitment No. 13) to enhance the Reactor Vessel Surveillance Program six months before the period of extended operation to:

- determine the reactor vessel neutron fluence by ex-vessel dosimetry, following withdrawal of the final capsule
- require that pulled and tested surveillance capsules be placed in storage for future reconstitution or reinsertion unless given NRC approval to discard
- require that plant operation changes be evaluated to determine the impact on reactor vessel embrittlement.

The staff finds that the program enhancements described in Commitment No. 13 are consistent with the discussion of program enhancements in LRA Section B2.1.17. The staff finds that the information in the FSAR supplement, as amended by letters dated October 31, 2012, and February 28, 2013, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Reactor Vessel Surveillance Program, the staff determined that the 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. 13 six months before 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 FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.11 Selective Leaching

Summary of Technical Information in the Application. LRA Section B2.1.19 describes the new Selective Leaching Program as consistent, with an exception, with GALL Report AMP XI.M33, "Selective Leaching." The LRA states that a one-time visual inspection and mechanical methods will be used to determine if a loss of material due to selective leaching is occurring. The LRA states that a sample of 20 percent of the population, up to a maximum of

25 component inspections, will be established for each material and environment combination. The LRA also states that if selective leaching is detected, followup evaluations will be performed. The LRA further states that the Selective Leaching Program will manage gray cast iron and copper alloy with greater than 15-percent zinc components within the fire protection, CVC, service water, compressed air, ESW, plant heating, fuel building HVAC, auxiliary building HVAC, containment purge, and oily waste systems that are within the scope of license renewal and exposed to treated water, raw water, waste water, or groundwater.

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.

The staff also reviewed the portions of the "parameters monitored or inspected" and "monitoring and trending" program elements associated with the exception to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this exception follows.

Exception. LRA Section B2.1.19 states an exception to the "parameters monitored or inspected" and "monitoring and trending" program elements. In this exception, the applicant stated that selective leaching inspections of buried gray cast iron components exposed to raw water or groundwater do not need to be provided if the components are within the scope of the fire protection system, have been installed in accordance with NFPA Standard 24, and the activity of the fire protection system jockey pump is required to be monitored on an interval not to exceed 1 month. The applicant stated that the exception is consistent with the fire protection aging management requirements of GALL Report AMP XI.M41, "Buried and Underground Piping and Tanks."

The staff noted that GALL Report AMP XI.M41 specifically states that the program does not address selective leaching and that GALL Report AMP XI.M33 is applied in addition to the GALL Report AMP XI.M41. Since selective leaching cannot be detected by flow monitoring or operation of a jockey pump, a hardness test or alternative mechanical examination is needed to determine if selective leaching is occurring. Therefore, by letter dated July 5, 2012, the staff issued RAI B2.1.19-1 requesting that the applicant explain how buried gray cast iron components in the fire protection system will be managed for loss of material due to selective leaching.

In its response dated August 6, 2012, the applicant stated that it revised the exception for the "detection of aging effects" program element to opportunistically inspect buried gray cast iron fire protection valves. The revised exception also requires that when any buried gray cast iron fire protection valves are removed from the fire protection system, the applicant will send specimens from at least one of the valves to a laboratory for metallurgical testing to determine the extent, if any, of selective leaching. The applicant also stated that a minimum of two metallurgical tests will be performed within the 5 years before entering the period of extended operation. The applicant revised the AMP and the FSAR supplement to reflect the revised exception.

The staff finds the applicant's response and the revised exception acceptable because the applicant will perform opportunistic inspections of the buried gray cast iron valves to detect if selective leaching is occurring. Although the applicant did not specify a sample size, it did commit to send two samples for metallurgical testing within the 5 years before entering the period of extended operation. Metallurgical testing more accurately detects degradation due to

selective leaching than simply scraping and chipping the metal. The staff's concern described in RAI B2.1.19-1 is resolved.

Based on its audit of the applicant's Selective Leaching Program and review of the applicant's response to RAI B2.1.19-1, 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.M33. The staff also reviewed the revised exception associated with the "detection of aging effects" program element, and its justification, and finds that the AMP, with the exception, is adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.19 summarizes operating experience related to the Selective Leaching Program. LRA Section B2.1.19 states that plant-specific operating experience was reviewed to ensure that the operating experience discussed in the corresponding GALL Report AMP is bounding. Additionally, the applicant searched the Callaway CAP to determine if selective leaching had been identified for components with the applicable material and environment combinations. The applicant stated that it did not identify any occurrences of selective leaching during its search of plant-specific historical information. The applicant also stated that plant-specific operating experience will be gained as the program is implemented during the period of extended operation and will be factored into the program through its 10 CFR 50 Appendix B Quality Assurance Program.

As discussed in the audit report, the staff reviewed CAR operating experience report for AMP XI.M33 and conducted an independent review of the applicant's CAR database. Although not cited in the LRA, the applicant identified one occurrence of selective leaching, which occurred in the EDG jacket water heat exchanger tubes. The tubes were constructed of admiralty brass. The removed tubes were sent to the EPRI NDE Center for examination. One of the root causes for the degraded tubes was "dezincification of the admiralty brass tubing." During RFO 17, the applicant replaced the EDG jacket water and lube oil cooler heat exchangers with ones that have super-austenitic stainless steel tubes, which are not susceptible to selective leaching. Additionally, during RFO 18, the applicant replaced the intercooler heat exchangers. The staff reviewed the AMR results for all heat exchanger tubes and confirmed that all tubes listed are constructed of materials not susceptible to selective leaching.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant. 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 GALL Report AMP XI.M33 was evaluated.

FSAR Supplement. LRA Section A1.19 provides the FSAR supplement for the Selective Leaching Program. By letter dated August 6, 2012, the applicant revised (LRA Amendment 5) the FSAR supplement to reflect a revision to the exception. The staff reviewed the revised FSAR 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 Selective Leaching Program within the 5-year period and no later than six months before entering the period of extended operation for managing aging of applicable components.

The staff finds that the information in the FSAR supplement, as amended by letters dated August 6, 2012, and February 28, 2013, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Selective Leaching Program, the staff concludes 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. 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 FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.12 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

Summary of Technical Information in the Application. LRA Section B2.1.23 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 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program addresses internal surfaces exposed to plant indoor air, ventilation atmosphere, atmosphere and weather, condensation, borated water leakage, diesel exhaust, and lubricating oil to manage cracking, loss of material, hardening, and loss of strength. The LRA also states that the AMP proposes to manage these aging effects through opportunistic visual inspections during periodic system, component, and maintenance activities. The LRA further states that inspections will be augmented by physical manipulation of polymers, and volumetric evaluations will be performed when appropriate.

As a result of recent staff reviews of several LRAs and of industry OE, the staff has determined that additional recommendations beyond those in the GALL Report should be considered in regards to managing loss of coating integrity for internal coatings of piping, piping components, heat exchangers, and tanks. By letters dated October 7, 2013, and March 25, 2014, the staff issued RAI 3.0.3-2 and RAI 3.0.3-2a, respectively, to address loss of coating integrity. In its responses dated December 20, 2013, and April 23, 2014, the applicant revised its Internal Surfaces in Miscellaneous Piping and Ducting Components Program to address loss of coating integrity for the service water pump strainers and the service water piping from the circulating and service water pump house to the ESW system connection. The staff's evaluations of the applicant's responses to RAI 3.0.3-2 and RAI 3.0.3-2a are documented in SER Section 3.0.3.4. The staff's evaluation of changes to LRA Sections B2.1.23 and A1.23 to address loss of coating integrity follows in the Staff Evaluation and FSAR Supplement sections below.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.M38.

As discussed in the audit report, the "scope of program" program element in the LRA does not describe the components included within the scope of the program. GALL Report AMP XI.M38 states that the program includes internal surfaces of metallic piping, piping components, ducting, polymeric components, and other components.

By letter dated June 5, 2012, the applicant submitted LRA Amendment 3, supplementing its description of the components included in the scope of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to include metallic piping, piping components, ducting, polymeric components, and other components. The applicant also updated the FSAR supplement in LRA Section A1.23 to reflect the specific component types that are in the scope of this program. The staff reviewed the supplemental information and noted that the description of components in the amended scope of the program is consistent with GALL Report AMP XI.M38.

LRA Amendment 3 also revised the program description to include additional guidance for conducting inspections of a representative sample of components. Specifically, the applicant amended the program to state that opportunistic inspections will be supplemented, if needed, to ensure that at least 20 percent of each component population (defined as components having the same material, environment, and aging effect combination), up to a maximum of 25 components, will be inspected. By letter dated March 13, 2014, the applicant provided additional detail in LRA Sections A1.23 and B2.1.23, stating that the representative sampling described above will occur, at a minimum, in each 10-year period during the period of extended operation and that these inspections will focus on components most susceptible to degradation. Opportunistic inspections will continue in each 10-year period despite meeting the sampling limit.

The staff reviewed the supplemental information regarding minimum inspection sampling and noted that it is consistent with GALL Report AMP XI.M38, as revised by LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation." This LR-ISG revises GALL Report AMP XI.M38 to include recommendations for minimum inspection sample size and frequency.

As amended by letters dated April 23, 2014, and June 5, 2014, LRA Section B2.1.23 provides a list of procedure activities associated with coatings inspections (e.g., base line inspections, extent of inspections), training and qualification of individuals involved in coating inspections, acceptance criteria, and corrective actions. These activities and the corresponding staff evaluation are documented in the responses to RAI 3.0.3-2a Request Nos. (2), (5), and (6) in SER Section 3.0.3.4.

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 the exception to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this exception follows.

Exception. LRA Section B2.1.23 states an exception to the "scope of program," "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements. In this exception, the applicant stated that the GALL Report recommends a visual examination of the internal surface of components within the scope of the program. The applicant also stated that, since the diesel exhaust is not available for internal surface inspection, a volumetric examination will be performed in place of visual examinations. The staff reviewed this exception against the corresponding program elements in GALL Report AMP XI.M38 and finds it acceptable because volumetric inspection is an adequate inspection

method to identify and manage cracking and loss of material for steel and stainless steel piping, piping components, and elements exposed to a diesel exhaust environment. The staff also reviewed the program's inspection frequency for managing these materials, environments, and aging effects and found the use of periodic, opportunistic inspections applied during periodic surveillance and maintenance activities to be consistent with the GALL Report recommendations and, therefore, acceptable.

Based on its audit of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components 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.M38. In addition, based on its review of the applicant's responses to RAIs 3.0.3-2 and 3.0.3-2a, the staff finds that the applicant's program changes to address loss of coating integrity are consistent with recommended measures acceptable to the staff for addressing loss of coating integrity for internal coatings as described in SER Section 3.0.3.4. 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 B2.1.23 summarizes operating experience related to the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The LRA states that internal surface monitoring using visual inspections is already in use at the Callaway plant with results trended and used for work planning and prioritization. The LRA states that a review of the current inspections applied to internal surface components has indicated that these inspections have been effective. The LRA also states that internal inspections have been used during maintenance activities for the centrifugal charging pump room cooler, which revealed a loss of material due to corrosion of threaded tube end plugs. The LRA further states that these indications were evaluated and corrective action was 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. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.M38 was evaluated.

FSAR Supplement. LRA Section A1.23, as amended by letters dated June 5, 2013, December 20, 2013, March 13, 2014, and April 23, 2014, provides the FSAR supplement for the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. The staff reviewed this FSAR supplement description of the program against the recommended description for this type of program as described in LR-2012-02, Table 3.0-1. The staff noted that the applicant committed (Commitment No. 18) to implement the new Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program six months before entering the period of extended operation for managing the applicable aging effects.

The staff finds that the information in the FSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, the staff 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 determined that the AMP, with the exception, 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 function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.13 Lubricating Oil Analysis

Summary of Technical Information in the Application. LRA Section B2.1.24 describes the existing Lubricating Oil Analysis Program as consistent, with enhancements, with GALL Report AMP XI.M39, "Lubricating Oil Analysis." The LRA states that the program manages oil environments to prevent loss of material and reduction of heat transfer. The LRA states that the program does not manage component surfaces directly, but maintains lubricating oil contaminants (primarily water and particulates) within acceptable limits, thereby preserving an environment that is not conducive to loss of material or reduction of heat transfer. The LRA also states that the program includes sampling, analysis, and condition monitoring activities to identify detrimental contaminants, such as water, particulates, and specific wear elements. The LRA further states that corrective actions are taken when the component's oil sample has phase separated water or water content exceeds an established target value. In addition the LRA states that the One-Time Inspection Program will be used to verify the effectiveness of the Lubricating Oil Analysis Program.

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 "scope of program," "detection of aging effects," and "acceptance criteria" program elements associated with enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B2.1.24 states an enhancement to the "scope of program" program element. In this enhancement, the applicant stated that before the period of extended operation, procedures will be enhanced to indicate that lubricating oil contaminants are maintained within acceptable limits, thereby preserving an environment not conducive to loss of material or reduction in heat transfer. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M39 and finds it acceptable because when it is implemented it will make the existing Lubricating Oil Program consistent with the GALL Report AMP.

Enhancement 2. LRA Section B2.1.24 states an enhancement to the "detection of aging effects," and "acceptance criteria" program elements. In this enhancement, the applicant stated that procedures will be enhanced to state the testing standards for water content and particle

count. 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 existing Lubricating Oil Program consistent with the GALL Report AMP.

Enhancement 3. LRA Section B2.1.24 states an enhancement to the "acceptance criteria" program element. In this enhancement, the applicant stated that procedures will be enhanced to state that phase separated water in any amount is not acceptable. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M39 and finds it acceptable because when it is implemented it will make the existing lubricating oil program consistent with the GALL Report AMP.

Based on its audit of the applicant's Lubricating Oil 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. In addition, the staff reviewed the enhancements associated with the "scope of program," "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 B2.1.24 summarizes operating experience related to the Lubricating Oil Analysis Program. The LRA states that in 2004, during an analysis of the auxiliary feedwater pump turbine lubricating oil, the oil sample from the reservoir was found to contain elevated water content (over 5,000 parts per million). The LRA states that the cause was identified as a turbine steam leak from the outboard gland casing that migrated into the lube oil system. The LRA also states that the steam leak was repaired, and the oil quality was restored through an oil change. The LRA further states that in 2009, during a routine analysis of the turbine-driven auxiliary feedwater pump lubricating oil, the oil sample on the outboard bearing reservoir was observed to be dark because of elevated iron content. The LRA states that the cause was determined to be an improperly installed bearing retainer ring, and the ring was subsequently installed correctly.

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 that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.M39 was evaluated.

FSAR Supplement. LRA Section A1.24 provides the FSAR supplement for the Lubricating Oil Analysis Program. The staff reviewed this FSAR 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 enhance the Lubricating Oil Analysis Program, as described above, six months before the period of extended operation for managing aging of applicable components during the period of extended operation.

The staff finds that the information in the FSAR supplement, as amended by letter dated February 28, 2013, 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 determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation through Commitment No. 19 six months before the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concluded that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the FSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.14 Buried and Underground Piping and Tanks

Summary of Technical Information in the Application. LRA Section B2.1.25 describes the new Buried and Underground Piping and Tanks Program as consistent, with exceptions, with GALL Report AMP XI.M41, "Buried and Underground Piping and Tanks." The LRA states that the AMP addresses steel, stainless steel, and HDPE piping and tanks exposed to a buried or underground environment to manage the effects of loss of material, cracking, blistering, and changes in color of the external surfaces of these components. The LRA also states that the AMP will manage these aging effects through preventive, mitigative, and inspection activities, including coatings, quality of backfill, cathodic protection, periodic inspections, and monitoring of the fire protection jockey pump activity.

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.

By letter dated December 19, 2012, the applicant submitted LRA Amendment 18, which stated that no direct visual inspections would be required for buried, in-scope HDPE piping because it is encased in controlled low-strength material. The staff finds this acceptable because it is consistent with LR-ISG-2011-03, "Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program (AMP) XI.M41, 'Buried and Underground Piping and Tanks'."

For the "scope of program," "preventive actions," "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.

During its audit, the staff reviewed license renewal drawings for the emergency diesel engine fuel oil storage and transfer system. The system appears to include in-scope underground piping; however, LRA Table 3.3.2-21, "Auxiliary Systems–Summary of Aging Management Evaluation–Emergency Diesel Engine Fuel Oil Storage and Transfer System," does not include any AMR items associated with underground piping. By letter dated July 5, 2012, the staff issued RAI B2.1.25-1 requesting that the applicant clarify whether there is underground piping in the emergency diesel engine fuel oil storage and transfer system that is within the scope of license renewal, and if there is, to describe how the piping will be managed for aging.

In its response dated August 6, 2012, the applicant stated that the emergency diesel engine fuel oil storage and transfer system has in-scope underground carbon steel piping, which will be age

managed for loss of material by the Buried and Underground Piping and Tanks Program. The applicant revised LRA Table 3.3.2-21 and Section B2.1.25 to include these components.

The staff finds the applicant's response acceptable because the aging of the underground components in the emergency diesel engine fuel oil storage and transfer system will be managed for loss of material by the Buried and Underground Piping and Tanks Program, which is consistent with the GALL Report, and the LRA has been amended to reflect the change. The staff's concern described in RAI B2.1.25-1 is resolved.

The "preventive actions" program element in GALL Report AMP XI.M41 recommends that coatings are provided based on environmental conditions, and if coatings are not provided, a justification is provided in the LRA. However, during its audit, the staff noted that the applicant's Buried and Underground Piping and Tanks Program states that coatings for buried stainless steel piping are only required to protect from a chloride environment to prevent stress-corrosion cracking. In addition, it states that the design temperature of the UHS is 95 °F (35 °C), and the maximum temperature of the refueling water storage tank is 120 °F (49 °C). The basis document further states that these temperatures are below the threshold temperature for stress-corrosion cracking as stated in GALL Report Section IX.D. The staff recognizes that the temperature threshold of 140 °F (60 °C) for stress-corrosion cracking in stainless steel in Table IX.D of the GALL Report implies that this threshold is applicable in treated water environments where the level of contaminants is controlled. However, the soil environment is not controlled to preclude the potential for significant levels of contaminants. Given that contaminants can accumulate in the soil due to normal environmental interactions, the 140 °F(60 °C) threshold may not apply to buried piping. In addition, the GALL Report, item AP-137, states that stainless steel components exposed to soil are susceptible to loss of material caused by pitting and crevice corrosion. By letter dated July 5, 2012, the staff issued RAI B2.1.25-2 requesting that the applicant provide the results of soil sampling in the vicinity of in-scope buried uncoated stainless steel piping that demonstrate that loss of material due to pitting and crevice corrosion, and stress-corrosion cracking will not occur due to exposure to contaminants in the soil. If this is not the case, the applicant was asked to state how these aging effects will be managed.

In its response dated August 6, 2012, as amended by letter dated August 21, 2012, the applicant stated that a soil survey conducted on July 9, 2012, sampled four locations in the same excavation ditch (measuring 15 feet by 12 feet by 12 feet) containing two in-scope stainless steel pipes. The results of the soil samples indicated that the pH was 7.6 to 8.0, chlorides were less than 2.7 ppm, soil resistivity was above 10,000 ohm-cm, and redox potential was in the range of -44 to 17 mV.

Based on a review of "Corrosion Resistance of Stainless Steels in Soils and in Concrete," paper presented at the Plenary Days of the Committee on the Study of Pipe Corrosion and Protection, Ceocor, Biarritz, October 2001, by Pierre-Jean Cunat, the staff noted the following:

- Buried pipelines suffer from corrosion when the pH is less than 4.5 and soil resistivity is less than 1000 ohm-cm.
- The paper states that, "[i]n principle, stainless steels should be in the passive state in soils, but the presence of water and aggressive chemical species such as chloride ions, sulphates and as well as types of bacteria and stray current can cause localized corrosion. This probability increases with increasing chloride ion content and higher redox potential."

- Table 2, “Critical value of Cl- for a number of stainless steels in aqueous chloride containing environment,” cites a threshold of 500 ppm for chlorides.

The staff finds the applicant’s response acceptable because four samples demonstrated a low corrosion potential for buried stainless steel piping; therefore, the 140 °F (60 °C) threshold is acceptable. The staff’s concern described in RAI B2.1.25-2 is resolved.

The “detection of aging effects” program element in GALL Report AMP XI.M41 states that the fire water jockey pump performance may be monitored in place of conducting excavated direct visual examinations of in-scope buried fire water system piping. During its audit, the staff noted that the applicant’s Buried and Underground Piping and Tanks Program credits this feature of AMP XI.M41; however, the staff noted that there have been numerous leaks in the fire water system piping. Therefore, it was not clear to the staff if the fire water jockey pump has sufficient non-running time between pump runs such that a change due to leakage could be detected. By letter dated July 5, 2012, the staff issued RAI B2.1.25-4, requesting that the applicant provide a summary of trend results for the fire water jockey pump for the past 5 years and explain whether there is sufficient non-running time between pump runs to detect leaks in in-scope buried piping. If the trend results are not capable of demonstrating this, state the basis for why monitoring fire water jockey pump performance is sufficient to ensure that the fire water system will meet its intended function during the period of extended operation.

In its response dated August 6, 2012, the applicant stated that a 5-year review of jockey pump run data demonstrated that typically there are 15 minutes between runs of the pump. The applicant stated that “[o]peration of the pump is monitored daily in the [c]ontrol [r]oom, and an alarm is received when run time becomes excessive (200 seconds).” The applicant also stated that a system engineer performs monthly trend reviews of pump operation. The applicant further stated that the jockey pump has been used successfully as a troubleshooting tool to locate leakage and quantify leaks by isolating portions of the system and checking run times on the jockey pump.

The staff finds the applicant’s response acceptable because a 5-year review of trend data demonstrated that there are sufficient periods of time when the pump is not running to use run time as a performance measure, in that a change from the normal 15 minutes downtime can be easily detected during trending. Therefore, the jockey pump trend data can be effectively used to age manage the buried fire protection piping. The staff’s concern described in RAI B2.1.25-4 is resolved.

The “acceptance criteria” program element in GALL Report AMP XI.M41 states that “[c]riteria for soil-to-pipe potential are listed in NACE RP0285-2002 and SP0169-2007.” NACE SP0169-2007 Section 6.2.2.2.2 states, “[i]n some situations, such as the presence of sulfides, bacteria, elevated temperatures, acid environments, and dissimilar metals, the criteria in Paragraph 6.2.2.1 may not be sufficient.” NACE SP0169-2007 Section 6.2.2.3.3 states, “[t]he use of excessive polarized potentials on externally coated pipelines should be avoided to minimize cathodic disbondment of the coating.” However, during its audit, the staff found that the “Close-Interval Survey and Direct Current Voltage Gradient Survey Buried Fire Water Protection Piping,” report dated May 7, 2008, recommended that for locations not meeting -850 mV criterion, station personnel should determine whether the alternative 100 mV potential shift criterion would demonstrate acceptable cathodic protection. In addition, it recommended that locations more negative than -1,200 mV be addressed to ensure that coating disbondment does not occur. LR-ISG-2011-03 states that when dissimilar metals are present in the environment (e.g., steel in relation to the copper grounding grid) the 100 mV criterion is only

acceptable if it can be demonstrated that the most noble metal will be adequately protected. If the applicant will use the 100 mV criterion on in-scope components during the period of extended operation, it should provide the basis for protecting the most noble metal. In addition, to verify consistency with the GALL Report AMP XI.M41, the staff must understand the applicant's approach to locations more negative than -1,200 mV. By letter dated July 5, 2012, the staff issued RAI B2.1.25-5 requesting that the applicant state whether the 100 mV polarization will be used as acceptance criterion, and if so, to state the basis for how the most noble buried in-scope material will be adequately protected. The staff also asked the applicant to state whether as-left survey findings will be allowed to be more negative than -1,200 mV, and if they will, to state the basis for why protective coating disbondment will not occur.

In its response, dated August 6, 2012, the applicant stated that:

> The Buried and Underground Piping and Tanks Program will use the 100 mV polarization as an acceptance criterion based on protecting the most noble metal in a dissimilar metal environment consistent with NACE SP0169-2007 Section 6.2 criteria. Protection of the most noble buried in-scope material will consist of evaluating the buried metallic piping and tanks that are electrically tied together. Using published industry galvanic series charts, the most anodic material will be identified and then raised 100 mV greater than the published number in relation to the copper-copper sulfate half-cell. Instances where protection cannot be demonstrated with this method will be entered into the Corrective Action Program. The EPRI sponsored Cathodic Protection User's Group will be used to provide operating experience associated with the 100 mV criteria.

In addition, the applicant stated that any instant-off reading more negative than -1200 mV will be investigated and appropriate corrective actions will be taken. Given that LR-ISG-2011-03, "Generic Aging Lessons Learned (GALL) Report Revision 2 AMP XI.M41, 'Buried and Underground Piping and Tanks," Table 6a, "Cathodic Protection Acceptance Criteria," provides specific cathodic protection criteria and does not cite NACE SP0169-2007, the intent of the applicant's reference to NACE SP0169-2007 is not clear. In relation to the applicant's statement, "[p]rotection of the most noble buried in-scope material will consist of evaluating the buried metallic piping and tanks that are electrically tied together," it is not clear to the staff why the applicant did not include the copper grounding grid in the evaluation scope. The staff could not determine how the applicant would apply the galvanic series chart in relation to as-found cathodic protection survey data. Finally, the staff believes that when the 100 mV polarization criterion is used, there must be some way (e.g., buried coupons, electrical resistance probes) to verify that the most anodic material is being protected. By letter dated October 1, 2012, the staff issued RAI B2.1.25-5a requesting that the applicant state: the basis for use of the 100 mV criterion absent a means to verify its effectiveness in preventing corrosion of the least noble metal; why the copper grounding grid was not included in the scope of buried items to be evaluated in relation to consideration of the galvanic series chart, specifically how the 100 mV criterion will be applied in relation to the galvanic series chart and for which materials the criterion will be used; what methods will be used to confirm the results of the cathodic protection surveys; and revise the Buried and Underground Piping and Tanks Program and FSAR supplement to reflect the use of this method and state what actions will be taken if the chosen method indicates that corrosion of in-scope buried components is occurring more rapidly than expected.

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

- Given that the in-scope buried piping is not electrically isolated either from the grounding grid or plant systems, bonding jumpers were used in the design of the cathodic protection system to minimize the effects of stray currents, and no data exists on the results of mixed metal impacts between the grounding grid and the buried piping. Thus, there is no basis at this time to support use of the 100mV.
- During research of galvanic series charts, it was identified that there exists a wide range of polarization readings for similar metals. This varying range did not provide an adequate basis for which to draw acceptance criterion from and therefore will not be used. The staff noted that this portion of the response eliminates the need to respond to why the copper grounding grid was not included in the scope of buried items to be evaluated because it only had to be included if the applicant was going to use the galvanic series to justify use of the 100 mV criterion.
- Corrosion coupons will be used to ensure that the cathodic protection system is providing sufficient protection for buried steel components within the scope of license renewal. Troubleshooting of the cathodic protection system will be conducted if corrosion rates are demonstrated to be higher than expected.

The applicant did not provide sufficient details on how coupons will be used, such as coupon characteristics, coupon placement, analysis of coupon results, acceptance criteria, and, during the time period when the effectiveness is indeterminate (i.e., it may take several years for the actual pitting or general corrosion to proceed beyond nominal thickness measurements of the coupon), how many inspections of under-protected buried pipe will occur. By letter dated December 27, 2012, the staff issued RAI B2.1.25-5b requesting that the applicant address the above issues.

In its response, dated January 24, 2013, the applicant removed references to the use of coupons from LRA Sections A1.25 and B2.1.25. The applicant stated that if the cathodic protection system does not meet the availability and effectiveness criteria of LR-ISG-2011-03, Table 4a, "Inspections of Buried Pipe," the Category D, E, or F inspection criteria will be used as applicable.

The staff finds the applicant's response acceptable because Table 4a inspection category D, E, or F is the appropriate inspection category to use if an installed cathodic protection system is not meeting availability and effectiveness goals. The applicant's proposal is consistent with LR-ISG-2011-03. The staff's concerns described in RAI B2.1.25-5, B2.1.25-5a, and B2.1.25-5b are resolved.

The staff also reviewed the portions of the "preventive actions" 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 B2.1.25 originally stated an exception to the "preventive actions" program element for HDPE piping that is not coated. By letter dated December 19, 2012, the applicant amended its LRA to remove Exception 1 from the Buried and Underground Piping and Tanks Program. The staff finds it acceptable to remove this exception because LR-ISG-2011-03 states that buried polymeric materials do not need to be coated.

Exception 2. LRA Section B2.1.25 originally stated an exception to the "detection of aging effects" program element to exclude UT of underground piping to detect internal corrosion. By letter dated December 19, 2012, the applicant amended its LRA to remove Exception 2 from the Buried and Underground Piping and Tanks program. The staff finds it acceptable to remove this exception because LR-ISG-2011-03 removed the recommendation to conduct UT examinations of underground piping to detect internal corrosion.

Exception 3. LRA Section B2.1.25 originally stated an exception to the "detection of aging effects" program element for expansion of samples if adverse indications are found in the expanded sample. By letter dated December 19, 2012, the applicant amended its LRA to remove Exception 3 from the Buried and Underground Piping and Tanks program. The staff finds it acceptable to remove this exception because the program is consistent with the revised AMP as documented in LR-ISG-2011-03, which states that if adverse indications are found in the expanded sample (i.e., the doubled sample size based on detecting the initial adverse condition), further increases in inspection sample size should be based on an analysis of extent of cause and extent of condition.

Based on its audit and review of the applicant's responses to RAIs B2.1.25-1, B2.1.25-2, B2.1.25-4, B2.1.25-5, B2.1.25-5a, and B2.1.25-5b, 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.M41, as modified by LR-ISG-2011-03. The staff also reviewed the exceptions associated with the "preventive actions" and "detection of aging effects" program elements and their justifications, including the basis for the removal of the exceptions, and finds that the AMP is adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.25 summarizes operating experience related to the Buried and Underground Piping and Tanks Program. The applicant stated that a fire protection loop leak was detected by a change in jockey pump performance, and the leak was promptly repaired. The applicant also stated that close interval and cathodic protection surveys have detected areas where the buried piping is not being adequately cathodically protected. Corrective actions were implemented or are in planning to adjust the system to provide the correct level of protection. The applicant further stated that from 2008 to 2009 portions of the ESW system were replaced with HDPE piping because of material conditions of the system, including pinhole leaks, pitting, and other localized degradation of the pressure boundary.

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, resulting in the issuance of an RAI, as discussed below.

LRA Table 3.3.2-4 states that there are steel piping, strainer, and valve components in the ESW system. Given that these steel components are in the same environment as the components that were replaced with HDPE material, it is possible that the degradation of the steel piping will occur at the same rate (on a unit length basis) as experienced in the past for the entire system. Also, given inconsistent site-wide performance of the cathodic protection system, the staff lacked sufficient information to determine if four inspections in each 10-year period will

ensure that the intended function(s) of the portions of the ESW that have not been replaced with HDPE piping will be met during the period of extended operation. By letter dated July 5, 2012, the staff issued RAI B2.1.25-6 requesting that the applicant state the basis for why four inspections in each 10-year period, starting 10 years before the period of extended operation, of buried steel piping in the ESW system are sufficient.

In its response dated August 6, 2012, the applicant stated that AMP XI.M41 recommends that four inspections be conducted in locations where cathodic protection has not been operated consistent with the AMP recommendations as long as coatings and backfill are consistent with AMP standards. The applicant also stated that, while the cathodic protection system is not currently being operated in accordance with the recommendations in the AMP, the ESW piping coatings and backfill do meet AMP XI.M41 recommendations and, therefore, four inspections in the 10-year period before the period of extended operation would be appropriate. The applicant further stated that, if operation of the cathodic protection system were to be brought into conformance with the recommendations in AMP XI.M41 during the period of extended operation, one inspection would be conducted in each 10-year period. The applicant stated if, after the cathodic protection system has been upgraded to meet the recommendations of AMP XI.M41, further degradation of the ESW piping were to occur, the number of inspections would be increased consistent with the recommendations in AMP XI.M41 for adverse conditions.

The staff noted that based upon a review of the response to RAI B2.1.1-1, associated with the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, and RAI B2.1.10-6, associated with the Open-Cycle Cooling Water System Program, the applicant categorized failures that have occurred in the ESW piping. The former RAI response states that leaks have occurred because of MIC and that no leaks have occurred since 2005. The latter RAI response states that only one leak has occurred to date in buried ESW piping, and this leak was caused by MIC. It was not clear to the staff if any of these leaks occurred because of external MIC. The staff noted that, based on its review of plant-specific operating experience, three leaks and one instance of coating degradation occurred in fire protection piping. It was not clear to the staff if the buried fire protection piping leaks and coating degradation occurred in locations with the same specifications for backfill as for the ESW piping. If the ESW piping leaks that the MIC caused originated from the outside surface of the buried piping or the fire protection buried piping leaks occurred in locations where the backfill specifications were the same as for the ESW piping, four inspections in the 10-year period before the period of extended operation would not be consistent with the recommendations in LR-ISG-2011-03. The staff also noted that LR-ISG-2011-03 revised the recommendation related to the number of buried piping inspections for instances in which cathodic protection does not meet availability and effectiveness goals from 4 per 10-year period (starting 10 years before the period of extended operation) to 7, 10, and 12 inspections in each of the 10-year periods, respectively. By letter dated October 1, 2012, the staff issued RAI B2.1.25-6a requesting that the applicant state if any of the ESW leaks originated from the outside surface of the buried piping, whether buried fire protection leaks originating from the outside surface of the buried piping occurred in locations where the backfill specifications were the same as those for the in-scope ESW piping, and the basis for why four inspections would be sufficient to ensure that the buried in-scope ESW piping would meet its intended function(s) for instances where cathodic protection does not meet availability and effectiveness goals recommended in LR-ISG-2011-03.

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

- None of the leaks in the ESW system originated from the outside surface of the buried pipe.
- The fire protection leaks that originated from the outside surface of buried piping were all on piping that was installed in commercial-grade backfill, whereas the backfill for buried piping within the power block meets the requirements of Table 2a, "Preventive Actions for Buried Piping and Tanks," of LR-ISG-2011-03.
- For sections of piping that do not meet the availability or effectiveness criteria (i.e., 85 percent and 80 percent, respectively) recommended in LR-ISG-2011-03, the inspection quantities of Preventive Action Category E of Table 4a, "Inspections of Buried Pipe," will be met.
- The number of inspections is consistent with Category E because backfill and coatings have been provided in accordance with Table 2a of LR-ISG-2011-03, and plant operating experience has not identified any leaks or significant coating degradation associated with in-scope buried piping.

The staff finds the applicant's response acceptable, in part, because (a) the leaks from ESW piping have not occurred because of external coating degradation, (b) the leaks originating from external coating degradation in the fire water system piping have been located in areas where the backfill is commercial grade, (c) the backfill within the power block (i.e., where in-scope piping is located) meets the quality requirements of Table 2a of LR-ISG-2011-03, and (d) there is no plant-specific operating experience related to piping leakage or coating degradation for in-scope buried piping where the backfill requirements meet Table 2a of LR-ISG-2011-03, such as ESW piping. In addition, the applicant cited the 85-percent availability and 80-percent effectiveness criteria for cathodic protection from LR-ISG-2011-03. The staff does not agree that all of the conditions for the applicability of the Category E inspection quantities have been met. In that regard, Table 4a, footnote 2.E.ii.c, states that, to use Category E, the soil must have been demonstrated to be not corrosive for the material type. Footnote 7 of this table provides the recommendations related to soil sampling. The staff recognizes that, in its response to RAI B2.1.25-2, above, the applicant provided soil sample results for portions of buried stainless steel piping. Given the potential for variability in soil corrosivity, these sample results do not meet the intent of the recommendations in footnote 7 for steel piping.

In addition, the staff recognizes that corrosion coupons will be used in areas where the cathodic protection system has been demonstrated to be ineffective. However, the staff did not believe that corrosion coupons can be substituted for soil sample results in regard to selection of the appropriate inspection category. By letter dated December 27, 2012, the staff issued RAI B2.1.25-6b requesting that the applicant provide soil sample results from the vicinity of buried in-scope steel piping sufficient to meet the recommendations of footnote 7 of LR-ISG-2011-03 Table 4a if available, and if not available, commit to completing the soil sampling during the 10-year period before the period of extended operation and in each subsequent 10-year period of extended operation. Alternatively, or if the soil is demonstrated to be corrosive, the staff requested that the applicant revise the Buried and Underground Piping and Tanks Program to ensure that the number of buried pipe inspections will meet Category F in the 10-year period before the period of extended operation and in each subsequent 10-year interval where the cathodic protection system does not meet the availability and effectiveness criteria of LR-ISG-2011-03, and revise the FSAR Supplement to reflect the need to conduct soil sampling where the cathodic protection system does not meet the criteria of LR-ISG-2011-03.

In its response dated January 24, 2013, the applicant stated the following:

- Soil sample results in the vicinity of buried in-scope steel piping are not available.
- When the cathodic protection system does not meet availability or effectiveness criteria, soil sampling will be conducted. The soil samples will be conducted during the 10-year period prior to the period of extended operation and in each subsequent 10-year period. The samples will be obtained and tested to the recommendations included in LR-ISG-2011-03, Table 4a, Footnote 7. If the soil is not corrosive, the number of inspections will be based on Table 4a inspection category E. If the soil is corrosive, the number of inspections will be based on Table 4a inspection category F.
- LRA Section B2.1.25 has been revised to state the requirements for soil sampling and the required number of inspections.
- LRA Section A1.25 has been revised to reflect the need to perform soil sampling.

The staff finds the applicant's response acceptable because the soil sampling frequency and parameters and inspection quantities based on the results of the soil sampling are consistent with LR-ISG-2011-03. The staff's concerns described in RAI B2.1.25-6, B2.1.25-6a, and B2.1.25-6b are resolved.

The staff noted that the response to RAI B2.1.14-5 related to the Fire Water System Program states "[t]he coal tar enamel that is on the FPS can be expected to have a service life ranging from 15 to 50 years depending on soil environment. Plant operating experience reflects that some of the coating for buried fire protection system piping is nearing the end of its service life." It is not clear to the staff whether the portion of the fire water system where the coating is nearing the end of its service life is in-scope piping. If in-scope piping is affected, then LR-ISG-2011-03 recommends that 15, 20, and 25 inspections be conducted in each respective 10-year period (e.g., 15 inspections in the 30- to 40-year period) starting 10 years before the period of extended operation if the cathodic protection system is not meeting availability or effectiveness goals. By letter dated October 1, 2012, the staff issued RAI B2.1.25-7 requesting that the applicant state whether the portion of the fire water system where the coating is nearing the end of its service life is within the scope of license renewal, whether the coating on any other buried in-scope piping is nearing the end of its service life, and, if the coatings on any buried in-scope steel piping are approaching end of life, state the basis for why four inspections would be sufficient to ensure that the buried in-scope ESW piping would meet its intended function(s) for instances where cathodic protection does not meet availability and effectiveness goals recommended in LR-ISG-2011-03.

In its response, dated October 31, 2012, the applicant stated that:

> The information previously provided regarding the 15-50 year service life for coal tar enamel applied to buried piping was given to provide general information about the coating for a variety of applications and environmental considerations. This time frame was not intended to convey that, at a specific time, the coating will no longer provide protection for the buried piping.

The applicant also stated that inspections of in-scope buried fire protection and other system piping have shown no significant degradation of the coatings, and there is no indication that there are any sections of buried piping which are nearing the end of the coating service life. The applicant updated Table 1 of the original response to

RAI B2.1.14-5 to reflect that the leak resulting from external degradation of the coating and piping was not in an in-scope portion of buried fire protection system.

The staff finds the applicant's response acceptable because the information on coating life was provided in a general, not specific, context; plant-specific inspections have demonstrated that in-scope coatings are not approaching end-of-life; and subsequent excavated direct visual inspections of buried piping conducted by this program will provide further evidence of the condition of the coatings on the piping. The staff's concern described in B2.1.25-7 is resolved.

Based on its audit, review of the application, and review of the applicant's responses to RAIs B2.1.25-6, B2.1.25-6a, B2.1.25-6b, and B2.1.25-7, 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 GALL Report AMP XI.M41 was evaluated.

FSAR Supplement. LRA Section A2.1.25 provides the FSAR supplement for the Buried and Underground Piping and Tanks Program. The staff reviewed this FSAR 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 applicant's Buried and Underground Piping and Tanks Program states that the preventive actions of the program will be consistent with the GALL Report. However, during its audit, the staff identified five CARs spanning 2006 through 2010 citing weakness in cathodic protection system performance. In addition, a Close-Interval Survey and Direct Current Voltage Gradient Survey-Buried Fire Water Protection Piping, dated May 2008, states that 23 percent of the fire protection system, representing 2,658 feet of piping, was inadequately protected. Given that plant-specific operating experience demonstrates a long period of degraded performance of the cathodic protection system, further details on cathodic protection system availability and effectiveness should be included in the FSAR supplement summary description. The licensing basis for this program for the period of extended operation may not be adequate if the applicant does not incorporate this information into its FSAR supplement.

By letter dated July 5, 2012, the staff issued RAI B2.1.25-3 requesting that the applicant revise the LRA Section A1.25 discussion of cathodic protection to include a discussion that the cathodic protection system meets NACE SP0169 or NACE RP0285, that it is monitored for effectiveness at least once a year, and that potential difference and current measurements are trended to identify changes in the effectiveness of the systems and coatings.

In its response, dated August 6, 2012, the applicant revised LRA Sections A1.25 and B2.1.25 to state that the cathodic protection system is operated consistent with the guidance in NACE SP0169-2007 for piping and NACE RP0285-2002 for tanks, that trending of the cathodic protection system is performed to identify changes in the effectiveness of the system and to ensure that the rectifiers are available to protect buried components, and that an annual cathodic protection survey is performed consistent with NACE SP0169-2007.

The staff finds the applicant's response acceptable because the FSAR supplement has been updated; therefore, the FSAR will include an adequate description of the programs and activities for managing the effects of aging for the period of extended operation related to operation of the cathodic protection system. The staff's concern described in RAI B2.1.25-3 is resolved.

The FSAR supplement for the Buried and Underground Piping and Tanks Program is consistent with the corresponding program description in SRP-LR Table 3.0-1.

The staff also noted that the applicant committed (Commitment No. 20) to implement the new Buried and Underground Piping and Tanks Program within the 10-year period and no later than six months before entering the period of extended operation for managing aging of applicable components.

The staff finds that the information in the FSAR supplement, as amended by letter dated August 6, 2012, January 24, 2013, and February 28, 2013, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Buried and Underground Piping and Tanks 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.M41, as modified by LR-ISG-2011-03. In addition, the staff reviewed the exceptions, including the basis for the removal of the exceptions, and determines that the AMP is adequate to manage the applicable aging effects. The staff also reviewed the amended FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.15 ASME Section XI, Subsection IWE

Summary of Technical Information in the Application. LRA Section B2.1.26 describes the existing ASME Section XI, Subsection IWE Program as consistent, with enhancements, with GALL Report AMP XI.S1, "ASME Section XI, Subsection IWE."

The LRA states that the ASME Section XI, Subsection IWE Program addresses the carbon steel containment liner plate and its integral attachments, containment hatches and airlocks, and pressure-retaining bolting exposed to plant indoor air to manage the effects of cracking, loss of material, loss of sealing, loss of preload, and loss of leak tightness through surface and volumetric examinations. The LRA states that the primary inspection method is a general visual examination (VT-1 and VT-3), and ultrasonic thickness measurements are performed, as required. The LRA also states that the IWE containment ISIs satisfy the requirements of the 2001 Edition of ASME Code Section XI (through the 2003 addenda), supplemented with the applicable requirements of 10 CFR 50.55a(b)(2)(ix). The LRA further states that the ASME Code edition, consistent with the provisions of 10 CFR 50.55a, will be used during the period of extended operation.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.S1. 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.S1 recommends the examination of moisture barriers for wear, damage, erosion, tear, surface cracks, or other defects that permit intrusion of moisture in the inaccessible areas of the pressure-retaining surfaces of the metal containment shell or liner. Furthermore, ASME Code Section XI, Subsection IWE, Table-2500-1 "Examination Category E-A" requires 100 percent general visual examinations of moisture barriers (E1.30) during each examination period. However, during its audit, the staff found that the applicant's ASME Section XI, Subsection IWE Program did not include inspection of moisture barriers as part of the IWE program. In addition, during the audit, the staff did not find any reference to the moisture barriers in the IWE periodic examination inspection reports. By letter dated July 9, 2012, the staff issued RAI B2.1.26-1

requesting the applicant to confirm if moisture barriers, as shown in Figure IWE-2500-1 of the ASME Code Section XI, Subsection IWE, are installed in the Callaway containment, and if moisture barriers have been installed, provide justification for not including the examinations of "moisture barriers" during each examination period.

In its response dated August 9, 2012, the applicant stated that "the Callaway Plant does not have a moisture barrier seal at the interface between the steel containment liner and the internal concrete structures. A fill slab is installed directly over the horizontal liner plate on the floor and directly against the vertical liner plate on the wall." As part of its response, the applicant revised the LRA (LRA Amendment 6) to delete reference to moisture barriers in the scope of the IWE inspections.

On August 23, 2012, the staff held a telephone conference call with the applicant to discuss its response to RAI B2.1.26-1. During the call, the applicant stated that based on the search of plant records, it was not able to find any documentation that could identify the existence of moisture barrier seals. Furthermore, NRC regional staff also verified drawings and photographs in the applicant's CAR 200403564 response to NRC IN 2004-09 and confirmed that Callaway does not have a moisture barrier seal. Therefore, the staff concluded that Callaway does not have a moisture barrier seal at the interface between the steel containment liner and the internal concrete structures.

The staff finds the applicant's response acceptable because the NRC regional staff confirmed the applicant's claim of absence of moisture barrier seals at the interface between the steel containment liner and the internal concrete structures and, therefore, the applicant's AMP is consistent with GALL Report AMP XI.S1 acceptance criteria. The staff's concern described in RAI B2.1.26-1 is resolved.

The staff also reviewed the portions of the "preventive actions" 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 B2.1.26 states an enhancement to the "preventive actions" program element. In this enhancement, the applicant stated that the procedures will be enhanced before the period of extended operation to specify that whenever replacement of bolting is required, bolting material, installation torque or tension, and use of lubricants and sealants are in accordance with the guidelines of EPRI NP-5769, EPRI TR-104213, and the additional recommendations of NUREG-1339. The staff reviewed this enhancement against the corresponding program element in the GALL Report AMP XI.S1 and finds it acceptable because when it is implemented it will prevent or mitigate degradation and failure of bolting and will make the ASME Section XI, Subsection IWE Program consistent with the recommendations identified in the GALL Report AMP.

Enhancement 2. The LRA Section B2.1.26 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that the procedures will be enhanced to perform additional surface examinations of stainless steel penetration sleeves, dissimilar metal welds, bellows, and steel components subject to cyclic loading for cracking, unless Appendix J testing is adequate to identify cracking. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S1 and finds it acceptable because, when it is implemented, it will make the ASME Section XI, Subsection IWE Program consistent with the recommendations identified in the GALL Report AMP.

Based on its audit of the applicant's ASME Section XI, Subsection IWE Program and review of the applicant's response to RAI B2.1.26-1, 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.S1. In addition, the staff reviewed the enhancements associated with the "preventive actions" and "detection of aging effects" program elements and finds that when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.26 summarizes operating experience related to the ASME Code Section XI, Subsection IWE Program. The LRA states that "[e]xams are conducted every other [RFO] to meet the frequency requirements of once per period of 3-1/3 years." The LRA states that a weld defect was identified in normal sump B that required an augmented examination during the next inspection period. The LRA states that the results of this evaluation were documented in Callaway's CAP. The LRA also states that the augmented examinations were completed in the first period of the second interval, and the weld defect was repaired. The LRA further states that based on a review of 10 years of Callaway operating experience, no significant degradation or corrosion of the components of the containment liner have been identified. However, in 2002, along the circumference of the containment building liner plate, five minor randomly spaced surface corrosion areas were identified, and repairs of these areas were completed. In addition the LRA states that these examples provide objective evidence that the ASME Section XI, Subsection IWE Program is capable of both monitoring and detecting the aging effects associated with the program, and that there is confidence that the continued implementation of the program will effectively identify aging before loss of intended function of the containment building liner plate.

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 that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.S1 was evaluated.

FSAR Supplement. LRA Section A1.26 provides the FSAR supplement for the ASME Section XI, Subsection IWE Program. The staff reviewed this FSAR 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 ASME Section XI, Subsection IWE Program six months before the period of extended operation for managing aging of applicable components during the period of extended operation. The staff finds that the information in the FSAR supplement, as amended by letter dated February 28, 2013, 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. Also, the staff reviewed the enhancements and confirmed that their implementation through Commitment No. 21, six months before 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 FSAR supplement for this AMP and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.16 ASME Section XI, Subsection IWF

Summary of Technical Information in the Application. LRA Section B2.1.28 describes the existing ASME Section XI, Subsection IWF Program as consistent, with enhancements, with GALL Report AMP XI.S3, "ASME Section XI, Subsection IWF." The LRA states that the ASME Section XI, Subsection IWF Program addresses supports for Class 1, 2, and 3 piping and components. The LRA also states that supports are selected and examined in accordance with the requirements of ASME Code Section XI, Subsection IWF. The LRA further states that the primary inspection method is periodic visual examination.

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 "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.S3 recommends refraining from using molybdenum disulfide and other lubricants containing sulfur for high-strength bolting applications. The "detection of aging effects" program element in GALL Report AMP XI.S3 recommends volumetric examination for high-strength structural bolting (actual measured yield strength greater than or equal to 150 ksi or 1,034 MPa) in sizes greater than 1-inch nominal diameter. However, during its audit, the staff found that the applicant's ASME Section XI, Subsection IWF Program does not clearly state that molybdenum disulfide and other lubricants containing sulfur have not been used in the past. The applicant's program also does not discuss the number of high-strength bolts within the scope of the program or how the bolts will be selected for volumetric inspection. Therefore, by letter dated July 9, 2012, the staff issued RAI B2.1.28-1 requesting that the applicant explain how many high-strength bolts are within the scope of the ASME Section XI, Subsection IWF Program and how bolts will be selected for volumetric inspection. The staff also requested the applicant to provide the plant-specific operating experience regarding lubricants containing sulfur and how these lubricants would be addressed during the period of extended operation.

In its response dated August 9, 2012, the applicant stated that a review of plant documentation, including drawings, specifications, procurement documents, and keyword database searches, did not identify any structural bolts greater than 1-inch diameter with a specified minimum yield strength greater than or equal to 150 ksi. Based on this review, the applicant concluded that there are no structural bolts within the scope of license renewal for which augmented volumetric examinations are necessary. The applicant further stated that molybdenum disulfide is excluded from the list of acceptable lubricants in plant procedures.

The staff finds the applicant's response acceptable because the applicant clearly stated that no high-strength structural bolts in sizes greater than 1-inch nominal diameter are within the scope of license renewal. The applicant also stated that molybdenum disulfide is not an acceptable lubricant per plant procedures. Therefore, stress-corrosion cracking of high strength structural bolts is not a concern, and the additional recommendations in the GALL Report AMP for high-strength bolting are not applicable. The staff's concern described in RAI B2.1.28-1 is resolved.

The "preventive actions" program element in GALL Report AMP XI.S3 recommends following the preventive actions discussed in Section 2 of the Research Council for Structural Connections, "Specification for Structural Joints Using ASTM A325 or A490 Bolts," if ASTM A325, ASTM F1852, or ASTM A490 bolts are used within the scope of the program. However, during its audit, the staff found that the applicant's ASME Section XI, Subsection IWF Program does not clearly state whether or not ASTM A325, ASTM F1852, or ASTM A490 bolts are used within the scope of the program. Therefore, by letter dated July 9, 2012, the staff issued RAI B2.1.28-2 requesting that the applicant clarify whether ASTM A325, ASTM F1852, or ASTM A490 bolts are used within the scope of the program, and if so explain how the recommended preventive actions will be addressed during the period of extended operation.

In its response dated August 9, 2012, the applicant stated that Commitment No. 22 and the enhancement associated with the "preventive actions" program element in LRA Section B2.1.28 have been revised to include the preventive actions discussed in Section 2 of the Research Council for Structural Connections, "Specification for Structural Joints Using ASTM A325 or A490 Bolts," if ASTM A325, ASTM F1852, or ASTM A490 structural bolts are used for replacement bolting during the period of extended operation.

The staff finds the applicant's response acceptable because the applicant revised the LRA and committed (Commitment No. 22) to use the GALL Report recommended reference for preventive actions associated with ASTM A325, ASTM F1852, and ASTM A490 structural bolts. The staff's concern described in RAI B2.1.28-2 is resolved.

The staff also reviewed the portions of the "preventive actions," "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 B2.1.28 states an enhancement to the "preventive actions" program element. In this enhancement, the applicant stated that whenever replacement of bolting is required, bolting material, installation torque or tension, and use of lubricants and sealants will be in accordance with the applicable EPRI guidelines, ASTM standards, American Institute of Steel Construction (AISC) specifications, and NUREG recommendations to prevent or mitigate SCC. 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 align the applicant's program with the recommended guidance provided in the GALL Report. Additional information regarding specific preventive actions taken for high-strength bolts is provided in the RAI discussions above.

Enhancement 2. LRA Section B2.1.28 states an enhancement to the "parameters monitored or inspected," and "detection of aging effects" program elements. In this enhancement, the applicant stated that high-strength bolting (actual measured yield strength greater than or equal to 150 ksi or 1,034 MPa) in sizes greater than 1-inch nominal diameter will receive a volumetric examination comparable to that of ASME Code Section XI, Table IWB-2500-1. In response to

RAI B2.1.28-1, the applicant clarified that no high-strength structural bolting exists within the scope of license renewal; therefore, the applicant deleted this enhancement. The staff reviewed this change and found it acceptable because there are no high-strength structural bolts within the scope of license renewal. Additional information on this issue is provided in the RAI discussions above.

Based on its audit of the applicant's ASME Section XI, Subsection IWF Program and review of the applicant's responses to RAIs B2.1.28-1 and B2.1.28-2, 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.S3. In addition, the staff reviewed the enhancements associated with the "preventive actions" program element and finds that when implemented it will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B2.1.28 summarizes operating experience related to the ASME Section XI, Subsection IWF Program. The LRA states that a review of the owner activity reports since 2000 indicates there have been no conditions found through IWF inspections that required repair, replacement, or engineering evaluation. The LRA further states that 100 percent of the supports required per category F-A were inspected during the past inspection interval, and no signs of aging were 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.

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.

ASME Code Section XI, Subsection IWF states, that to the extent practical, the same supports selected for examination during the first inspection interval shall be examined during each successive inspection interval. Recent industry operating experience has revealed situations where supports within the IWF sample were degraded, but did not meet the ASME Code threshold for repair. The supports were reworked to as-new condition and remained in the IWF sample. If ASME Code Section XI, Subsection IWF supports that are part of the inspection sample are reworked to as-new condition, they are no longer representative of the other supports in the population in regard to age-related degradation. Subsequent ASME Code Section XI, Subsection IWF inspections of the same sample would not represent the age-related degradation of the rest of the population. The LRA and the associated basis documents provided no discussion of how this issue would be addressed, or how the IWF sample would be altered if a support within the original sample was reworked. Therefore, by letter dated July 9, 2012, the staff issued RAI B2.1.28-3 requesting the applicant explain how the ASME Section XI, Subsection IWF Program would address a situation where supports in the sample population are reworked or replaced even though they do not necessarily require corrective actions per the ASME Code Section XI, Subsection IWF acceptance criteria.

In its response dated August 9, 2012, the applicant stated that the ASME Code Section XI, Subsection IWF Program has not reworked or replaced any supports in the sample population unless corrective actions were required per ASME Code Section XI, Subsection IWF

acceptance criteria. The applicant further stated that if supports are reworked or replaced they are not included in subsequent sample selections.

The staff finds the applicant's response acceptable because the applicant stated that supports that have been reworked in the past are not included in the inspection sample population, and any supports that are reworked or replaced in the future will be removed from the subsequent inspection population. Removing reworked or replaced supports from future inspection samples addresses the staff's concern that the supports may no longer be representative of the general population. The staff's concern described in RAI B2.1.28-3 is resolved.

Based on its audit, review of the application, and review of the applicant's response to RAI B2.1.28-3, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience, and that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.S3 was evaluated.

FSAR Supplement. LRA Section A1.28 provides the FSAR supplement for the ASME Section XI, Subsection IWF Program. The staff reviewed this FSAR 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. 22) to implement the associated enhancements of the existing ASME Section XI, Subsection IWF Program six months before the period of extended operation for managing aging of applicable components during the period of extended operation. The staff finds that the information in the FSAR supplement, as amended by letters dated August 9, 2012, and February 28, 2013, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's ASME Section XI, Subsection IWF Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation through Commitment No. 22 six months before 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 FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.17 Structures Monitoring

Summary of Technical Information in the Application. LRA Section B2.1.31 as amended by letters dated August 9, 2012, and October 11, 2012, describes the existing Structures Monitoring Program as consistent, with enhancements, with GALL Report AMP XI.S6, "Structures Monitoring." The LRA states that the Structures Monitoring Program implements the requirements of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," consistent with guidance of NUMARC 93-01, Revision 2, "Industry Guidelines 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". The LRA states that the Structures Monitoring Program monitors the condition of structures and structural supports that are within the scope of license renewal to manage the following aging effects:

- concrete cracking and spalling
- cracking
- cracking and distortion
- cracking, blistering, change in color
- cracking, loss of material
- cracking, loss of bond, and loss of material (spalling, scaling)
- increase in porosity and permeability, cracking, loss of material (spalling, scaling)
- increase in porosity and permeability, loss of strength
- loss of material
- loss of material (spalling, scaling) and cracking
- loss of mechanical function
- loss of preload
- loss of sealing
- reduction in concrete anchor capacity

The LRA also states that Callaway is committed to RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," and the scope of the Structures Monitoring Program includes water-control structures and masonry walls. The LRA, as amended by letter dated August 9, 2012, clarifies that the inspections of all structural components, including masonry walls and water-control structures, are performed at intervals of no more than 5 years. The LRA further states that Callaway does not take credit for any coatings to manage the aging of structural components, and that coating degradation is used only as an indicator of the condition of underlying 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.S6.

For the "scope of program," "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 "scope of program" program element in GALL Report AMP XI.S6 recommends inspection of all structures, structural components, component supports, and structural commodities within the scope of license renewal that are not covered by other structural AMPs. Examples of structures, structural components, and commodities in the scope of the program are:

- concrete and steel structures
- structural bolting
- anchor bolts and embedments
- component support members
- pipe whip restraints and jet impingement shields
- transmission towers
- panels and other enclosures
- racks, sliding surfaces
- sump and pool liners
- electrical cable trays and conduits
- trash racks associated with water control structures
- electrical duct banks
- manholes, doors, penetration seals, and tube racks

However, during its audit, the staff found that the applicant's Structures Monitoring Program has excluded penetrations, pipe and raceway supports, cable trays, anchor bolts, transmission towers, electrical conduits, and the UHS retention pond from the scope of the existing AMP. The staff notes that the applicant has committed to enhance the procedures to specify inspections of penetrations, transmission towers, electrical conduits, raceways (equivalent to pipe and raceway supports), cable trays, electrical cabinets and enclosures, and associated anchorages. However, to date, none of these structures have been inspected and the applicant has no plans to inspect them until the period of extended operation. Baseline inspection and trending of degradation in the excluded structures before the period of extended operation is necessary for appropriate aging management. By letter dated July 9, 2012, the staff issued RAI B2.1.31-5 requesting the applicant to provide a summary description of plans and a schedule for baseline inspection and trending of degradation of the structures excluded by the existing program, but which are included as an enhancement to the Structures Monitoring Program for the period of extended operation. The staff also requested the applicant to provide the technical basis for not including these structures in the baseline inspection as part of the Structures Monitoring Program.

In its response dated August 9, 2012, the applicant stated that:

> …baseline inspections of penetrations, transmission towers, electrical conduits, raceways, cable trays, electrical cabinets/enclosures, and associated anchorages will be completed by December 31, 2017. These baseline inspections will be performed as part of the Structures Monitoring [P]rogram, which has been enhanced to add these components to its scope. Previously, these components were considered to be part of their respective mechanical or electrical systems. Beginning with these baseline inspections and continuing through the period of extended operation, these components will be within the scope of the Structures Monitoring [P]rogram for all inspections, monitoring, and trending that may be required. The [UHS] retention pond is already within the scope of the Structures Monitoring [P]rogram and will continue to be so.

The staff finds the applicant's response acceptable because the applicant has committed (Commitment No. 23) to complete the baseline inspection of these components by December 31, 2017. A baseline inspection of these components, before the period of extended operation, will provide for adequate monitoring and trending, which is necessary to demonstrate that the components will be age managed through the period of extended operation. The staff's concern described in RAI B2.1.31-5 is resolved.

The "parameters monitored or inspected" program element in GALL Report AMP XI.S6 recommends inspection of all structures on a frequency not to exceed 5 years. However, during its audit, the staff found that although the applicant's Structures Monitoring Program basis document states that inspections are performed at intervals of not more than 5 years, no discussion of the inspection interval is provided in the LRA or the FSAR supplement program summary. The inspection frequency needs to be captured in the FSAR supplement to provide the staff reasonable assurance that the programs will be properly implemented during the period of extended operation. By letter dated July 9, 2012, the staff issued RAI B2.1.31-1 requesting that the applicant include a statement of the inspection interval in the FSAR supplement for the Structures Monitoring, Masonry Wall, and RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants programs.

In its response dated August 9, 2012, the applicant stated that the FSAR supplements of the Structures Monitoring, Masonry Wall, and RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants programs have been revised to specify that inspections of all structural components, including masonry walls and water-control structures, are performed at intervals of no more than 5 years.

The staff finds the applicant's response acceptable because the FSAR supplements for the Structures Monitoring, Masonry Wall, and RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants programs have been revised to specify that inspections of all structural components, including masonry walls and water-control structures, are performed at intervals of no more than 5 years, which is consistent with the inspection frequency recommended in GALL Report AMPs XI.S5, XI.S6, and XI.S7. The staff's concern described in RAI B2.1.31-1 is resolved.

The "parameters monitored or inspected" and "detection of aging effects" program elements in GALL Report AMP XI.S6 state that ACI 349.3R and ANSI/American Society of Civil Engineers (ASCE) 11 provide an acceptable basis for selection of parameters to be monitored or inspected for concrete and steel structural elements and that qualifications of inspection and evaluation personnel specified in ACI 349.3R are acceptable for license renewal. However, during its audit, the staff found that the applicant's Structures Monitoring Program basis documents indicate that the inspection methods, including walkdown examination guidance, and qualification requirements for inspectors are not consistent with ACI 349.3R. Callaway procedure ESP-ZZ-01013, Section 4.0, states that an assigned engineer from the civil/structural design group will perform the engineering responsibilities for the Maintenance Rule Structures Inspection Program. The assigned engineer will possess the experience and skills in civil/structural engineering, consistent with the requirements of the current civil/structural position guide and engineering qualification module. This is inconsistent with the requirements specified in ACI 349.3R, which states that the responsible-in-charge engineer should be a licensed professional engineer, knowledgeable in the design, evaluation, and ISI of concrete structures and performance requirements of nuclear safety-related structures; or structural engineering graduate of an Accreditation Board for Engineering and Technology, Inc., accredited college or university with at least 10 years' experience in the design, construction, and inspection of concrete structures, and with knowledge of the performance requirements of nuclear safety-related structures and potential degradation processes. In addition, ACI 349.3R recommends a three-tier quantitative evaluation criteria for inspection of structures; however, the walkdown guidelines in Callaway procedure ESP-ZZ-01013 require inspection based on a qualitative acceptance criteria. By letter dated July 9, 2012, the staff issued RAI B2.1.31-2 requesting that the applicant explain the reason for inconsistency in inspection methods and inspector qualifications as described in LRA Section B2.1.31 and implementing procedure ESP-ZZ-01013.

In its response dated August 9, 2012, as supplemented by letter dated October 11, 2012, the applicant stated that "LRA Table A4-1 Item 23, documents the plant commitment to enhance the Structures Monitoring Program procedures to specify inspector qualifications in accordance with ACI 349.3R-96." The applicant further stated that LRA Section B2.1.31 and LRA Table A4-1 Commitment No. 23 have been revised to enhance the Structures Monitoring Program procedures to specify that acceptance criteria and critical parameters for monitoring degradation and guidance for identifying unacceptable conditions requiring further technical evaluation or corrective action are in accordance with the three-tier quantitative evaluation criteria recommended in ACI 349.3R.

The staff finds the applicant's response acceptable because the applicant has committed (Commitment No. 23) to enhance the program to specify inspector qualification in accordance with ACI 349.3R and, by letter dated October 11, 2012, the applicant revised the LRA and Commitment No. 23 to clarify that the Structures Monitoring Program procedures will be enhanced to specify that acceptance criteria and critical parameters for monitoring degradation and guidance for identifying unacceptable conditions requiring further technical evaluation or corrective action are in accordance with the three-tier quantitative evaluation criteria recommended in ACI 349.3R. The staff's concern described in RAI B2.1.31-2 is resolved.

The "detection of aging effects" program element in GALL Report AMP XI.S6 recommends periodic sampling and testing of groundwater and assessing the impact of any changes in its chemistry on below-grade concrete structures. For plants with non-aggressive groundwater/soil (pH greater than 5.5, chlorides less than 500 ppm, or sulfates less than 1,500 ppm), the program recommends: (a) evaluating the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas and (b) examining representative samples of the exposed portions of the below-grade concrete, when excavated for any reason. The GALL Report also recommends that for plants with aggressive groundwater/soil (pH less than 5.5, chlorides greater than 500 ppm, or sulfates greater than 1,500 ppm) or where the concrete structural elements have experienced degradation, a plant-specific AMP accounting for the extent of the degradation experienced should be implemented to manage the concrete aging during the period of extended operation. However, during its audit, the staff found that the applicant's Structures Monitoring Program has identified two wells that have shown seasonal increases in chloride levels of up to 680 mg/L while the pH and sulfate concentrations have remained non-aggressive. The LRA states that the aplicant will continue to monitor the results from the groundwater samples and will perform an engineering evaluation to determine if any adverse aging effects have occurred in any inaccessible concrete structural elements. The LRA does not provide any details on how the aging of the inaccessible concrete elements will be managed during the period of extended operation because of the presence of high chloride concentrations. By letter dated July 9, 2012, the staff issued RAI B2.1.31-6 requesting that the applicant provide historical results, including season variations, for groundwater chemistry, and provide details on how the aging of the inaccessible concrete elements will be managed during the period of extended operation because of the presence of high chloride concentrations.

In its response dated August 9, 2012, the applicant stated that:

> [b]eginning in November 2009, 24 monthly groundwater samples were taken from 11 sampling wells around the Callaway site. Sulfates and pH levels were well within acceptable limits with no significant seasonal variations. Samples taken from one well in August and September of 2010 showed chloride levels of 520 ppm and 570 ppm. In March and April of 2011, samples taken from a different well had chloride levels of 660 ppm and 610 ppm. All other samples showed chloride to be below the 500 ppm threshold for classifying groundwater as aggressive.

The applicant also stated that an engineering evaluation was performed to assess the impact, if any, on existing below-grade structures because of the elevated levels of chloride that have been detected in the groundwater monitoring wells, concluding that there is no indication that Callaway has concrete or reinforcing steel degradation resulting from aggressive groundwater. The applicant further stated that:

> Callaway will continue to monitor groundwater for pH, chlorides, and sulfates every [5] years through the period of extended operation, and the results will be evaluated by engineering to assess the impact, if any, on below-grade structures. The Structures Monitoring [P]rogram monitors the plant structures with scheduled visual examination of the accessible structures and opportunistic examination of inaccessible structures. These examinations will continue through the period of extended operation to confirm the absence of concrete degradation due to aggressive groundwater.

The staff finds the applicant's response acceptable because although the increased chloride levels have since returned within the limits for classifying the environment as non-aggressive, the applicant conducted an engineering evaluation and concluded that there was no indication of concrete or reinforcing steel degradation resulting from aggressive groundwater. Additionally, the applicant stated that opportunistic inspections of inaccessible areas are performed and that pH, chlorides and sulfates will continue to be monitored every 5 years through the period of extended operation, which is consistent with the GALL Report recommendations. Therefore, the staff's concern described in RAI B2.1.31-6 is resolved.

The "acceptance criteria" program element in GALL Report AMP XI.S6 recommends that the acceptance criteria be derived from design codes and standards that include ACI 349.3R, ACI 318, ANSI/ASCE 11, or the relevant AISC specifications as applicable, and consider industry and plant operating experience. The criteria are directed at the identification and evaluation of degradation that may affect the ability of the structure or component to perform its intended function. Applicants that are not committed to ACI 349.3R and elect to use plant-specific criteria for concrete structures should describe the criteria and provide a technical basis for deviations from those in ACI 349.3R. However, during its audit, the staff found that the applicant's Structures Monitoring Program basis document states that the Callaway Structures Monitoring Program provides guidance for the determination of performance criteria for SSCs included within the scope of the Maintenance Rule. These guidelines were used to establish the inspection attributes for SSCs. Callaway's Structures Monitoring Program uses "Acceptable," "Acceptable with Deficiencies," and "Unacceptable" to classify levels of aging effects for each inspection attribute. The staff also notes that the applicant has committed (Commitment No. 23) to enhance the Structures Monitoring Program to quantify acceptable criteria and critical parameters for monitoring degradation. As part of its enhancement to the AMP, the applicant has also committed (Commitment No. 23) to incorporate in its procedures applicable industry codes, standards, and guidelines for acceptance criteria. The staff was not clear what industry standard the acceptance criteria was based on, nor was the acceptance criteria consistent with ACI 349.3R. By letter dated July 9, 2012, the staff issued RAI B2.1.31-3 requesting that the applicant provide the basis for the acceptance criteria described in Appendix D of procedure ESP-ZZ-01013. The staff also requested the applicant to explain the inconsistency between the Structures Monitoring Program acceptance criteria of "Acceptable," "Acceptable with Deficiencies," and "Unacceptable," as identified in procedure ESP-ZZ-01013 Section 7.5 and the quantitative acceptance criteria described in ESP-ZZ-01013, Appendix D.

In its response dated August 9, 2012, the applicant stated the following:

> [t]he acceptance criteria for the Structures Monitoring [P]rogram are based on those provided in ACI 349.3R. For inspection of components and materials that are not specifically addressed in ACI 349.3R, the acceptance criteria are modified as necessary to account for the nature of the component being inspected. The markup of the [s]tructures [m]onitoring procedure has been

> revised to align with the criteria of ACI 349.3R and to clarify the definitions of the [a]cceptance [c]riteria categories so that they also align with ACI 349.3R.

In addition, in a letter dated October 11, 2012, the applicant revised LRA Table A4-1, Commitment No. 23, to clarify that the acceptance criteria will be revised to be in accordance with the three-tier quantitative evaluation criteria recommended in ACI 349.3R. The staff finds the applicant's response acceptable because the applicant committed (Commitment No. 23) to revise the structures monitoring procedure to align with the criteria of ACI 349.3R. Therefore, the staff's concern described in RAI B2.1.31-3 is resolved.

The staff also reviewed the portions of the "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements associated with 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 B2.1.31 states an enhancement to the "scope of program" program element. In this enhancement, as amended by letter dated May 6, 2014, the applicant stated that procedures will be enhanced to include the main access facility, the nitrogen storage tank foundation and pipe trench, and the reinforced concrete structures under the turbine building and in the yard (which provide a return flow path for the circulating water system), in the scope of Structures Monitoring Program. 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 make the program consistent with the GALL Report recommendations by including all structures within the scope of license renewal, not covered by other structural AMPs, in the scope of the program.

Enhancement 2. LRA Section B2.1.31 states an enhancement to the "preventive actions" program element. In this enhancement, the applicant stated that plant procedures will be enhanced to specify that guidelines of EPRI NP-5769, EPRI NP-5067, EPRI TR-104213, and the additional recommendations of NUREG-1339 will be used whenever replacement of bolting is required. The applicant also stated that plant procedures will be enhanced to specify the preventive actions for storage, lubricants, and SCC potential discussed in Section 2 of the Research Council for Structural Connections publication, "Specification for Structural Joints Using ASTM A325 or A490 Bolts," for ASTM A325, ASTM F1852, and/or ASTM A490 structural bolts. 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 make the program consistent with the GALL Report recommendations.

Enhancement 3. LRA Section B2.1.31, as amended by letter dated August 9, 2012, states an enhancement to the "scope of program" and "parameters monitored or inspected" program elements. In this enhancement, the applicant stated that procedures will be enhanced to specify inspections of penetrations, transmission towers, electrical conduits, raceways, cabletrays, electrical cabinets and enclosures, and associated anchorages, and to complete a baseline inspection of these components before December 31, 2017. The applicant also stated that procedures will be enhanced to specify that groundwater is monitored for pH, chlorides, and sulfates; and every 5 years, at least two samples are tested and the results are evaluated by engineering to assess the impact, if any, on below-grade structures. 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 make the program consistent with the

GALL Report recommendations for periodic sampling of groundwater chemistry (pH, chlorides, and sulfates) to assess its impact, if any, on below-grade concrete structures.

Enhancement 4. LRA Section B2.1.31 states an enhancement to the "parameters monitored or inspected" program element. In this enhancement, the applicant stated that procedures will be enhanced to specify that structural bolts greater than 1-inch in diameter with actual measured yield strength greater than or equal to 150 ksi are evaluated for susceptibility to SCC, and if necessary, visual inspections are supplemented with volumetric or surface examinations. However, by letter dated August 9, 2012, in response to RAI B2.1.28-1, the applicant amended the LRA to delete this enhancement because it performed a review and concluded that there are no structural bolts within the scope of license renewal for which augmented volumetric examinations are required. The staff's review of the applicant's response to RAI B2.1.28-1 is documented in SER Section 3.0.3.2.16.

Enhancement 5. LRA Section B2.1.31 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that procedures will be enhanced to specify inspector qualification 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 make the program consistent with the GALL Report recommendations for inspector qualifications.

Enhancement 6. LRA Section B2.1.31, as amended by letters dated August 9, 2012, and October 11, 2012, states an enhancement to the "acceptance criteria" program element. In this enhancement, the applicant stated that procedures will be enhanced to quantify acceptance criteria and critical parameters for monitoring degradation and to provide guidance for identifying unacceptable conditions requiring further technical evaluation or corrective action in accordance with the three-tier quantitative evaluation criteria recommended in ACI 349.3R. The applicant also stated that procedures will be enhanced to incorporate applicable industry codes, standards, and guidelines for acceptance criteria.

By letter dated August 9, 2012, in response to RAI B2.1.31-4, as discussed below, the applicant revised this enhancement to state that procedures will be enhanced to specify that degradation associated with seismic isolation gaps, obstructions of these gaps, or questionable material in these gaps, will be inspected and evaluated. By letter dated January 24, 2013, the applicant revised the LRA to indicate that initial inspections have been completed and any corrective actions resulting from these inspections will be completed no later than December 31, 2017. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds it acceptable because the applicant has revised the Structures Monitoring Program to clarify that acceptance criteria will be in accordance with ACI 349.3R, and when it is implemented, it will make the program consistent with the GALL Report recommendations for acceptance criteria. Additionally, the applicant has committed (Commitment No. 23) to complete corrective actions resulting from initial inspections no later than December 31, 2017.

Based on its audit of the applicant's Structures Monitoring Program and review of the applicant's responses to RAIs B2.1.31-1, B2.1.31-2, B2.1.31-3, B2.1.31-5, and B2.1.31-6, 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 the "scope of program," "preventive actions," "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 B2.1.31 summarizes operating experience related to the Structures Monitoring Program. The LRA states that a 2002 structural inspection report of the fuel building identified an instance of cracking on the interior face of the exterior wall, with leachate observed coming through the crack; however, the leaking was not severe enough to warrant corrective action. The LRA states that inspections in 2010 did not identify any further cracking or leaking of leachate in this area.

The LRA also states that the applicant performs continuous monitoring of the spent fuel pool liner leak chase channels. The observed leakage has been small, remained steady, and does not challenge makeup capability. The exterior spent fuel pool walls show no evidence of external leakage, thus indicating that the leakage is contained within the leak chase channels.

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 GALL Report recommends that the Structures Monitoring Program operating experience, including past corrective actions resulting in program enhancements or additional programs, should provide objective evidence to support a determination 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. During the audit, the staff reviewed operating experience and performed plant walkdowns. During the audit, the staff observed that elastomers in the seismic gaps of the containment, turbine and auxiliary buildings have been degraded and are not functional. The applicant identified this condition in 2006 and has caused in-leakage of ground and rain water into the buildings. In addition, the staff observed that in one area in the auxiliary building, the elastomer has been replaced with a foreign material. Lack of flexible elastomer gap can cause seismic interaction between the buildings, resulting in stresses not considered in the design that may affect the structural integrity of the structures during the period of extended operation. By letter dated July 9, 2012, the staff issued RAI B2.1.31-4 requesting that the applicant provide a summary of the plans and its schedule to replace the nonfunctional elastomers located in seismic gaps.

In its response dated August 9, 2012, the applicant stated that:

> [s]eismic isolation gaps at the roof, base slab, and exterior walls are constructed with waterstops embedded in the concrete. The elastomeric compressible material that is visible at the edge of the joint is a separate component from the waterstops. FSAR-SP Figure 3.8-85 shows typical isolation joint details. The intended function of the seismic isolation gap compressible material is to shelter and protect the gap from debris intrusion so that seismic isolation is maintained.

The applicant also stated that:

> [i]nspections for all accessible seismic gaps between buildings will be performed before December 31, 2012. An engineer familiar with the seismic design of the plant will evaluate the results of these inspections. Any corrective actions resulting from these inspections will be completed no later than December 31, 2017.

The staff finds the applicant's response acceptable because, by letter dated January 24, 2013, the applicant revised the LRA to indicate that the initial inspections have been completed and the applicant has committed (Commitment No. 23) to take any corrective actions necessary by December 31, 2017. Inspection of these gaps, removal of foreign material, and corrective action taken to ensure the gaps remain free of foreign material will ensure that seismic isolation of the buildings is maintained. The staff's concern described in RAI B2.1.31-4 is resolved.

Based on its audit and review of the application, and review of the applicant's response to RAI B2.1.31-4, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program and that implementation of the program has resulted in the applicant taking corrective actions.

FSAR Supplement. LRA Section A1.31 provides the FSAR supplement for the Structures Monitoring Program. The staff reviewed this FSAR 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 Structures Monitoring Program procedures six months before the period of extended operation for managing aging of applicable components during the period of extended operation. The staff finds that the information in the FSAR supplement, as amended by letters dated August 9, 2012, October 11, 2012, and February 28, 2013, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Structures Monitoring Program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation through Commitment No. 23 six months before 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 FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.18 Protective Coating Monitoring and Maintenance Program

Summary of Technical Information in the Application. LRA Section B2.1.33 describes the existing Protective Coating Monitoring and Maintenance Program as consistent, with an exception and enhancements, with GALL Report AMP XI.S8, "Protective Coating Monitoring and Maintenance Program." The LRA states the program manages "loss of coating integrity for Service Level I 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 LRA states that the program includes visual

examination of accessible Service Level I coatings inside containment, including those applied to the steel containment liner, structural steel, supports, penetrations, concrete walls and floors.

The LRA states that general visual inspections of the containment building Service Level I coatings are conducted once each fuel cycle. The LRA also states that characterization of deficient areas is performed to allow evaluation of the deficiency for future surveillance or repair, and prioritization of repairs. The LRA further states that characterization of blistering, cracking, flaking, peeling, delamination, and rusting is consistent with ASTM D 5163-08, "Standard Guide for Establishing a Program for Condition Assessment of Coating Service Level I Coating Systems in Nuclear Power Plants."

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.S8.

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 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 B2.1.33 states an exception to the "scope of program" program element. In this exception the applicant stated that it will not be committing to all of the requirements noted in RG 1.54, Revision 2, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants." RG 1.54 covers Service Level I, II, and III coatings, whereas GALL Report AMP XI.S8 is applicable to Service Level I coating. The applicant is committed to RG 1.54 in as much as it addresses Service Level I coating. The staff reviewed this exception against the corresponding program element in GALL Report AMP XI.S8 and finds it acceptable because the program is committed to those requirements in RG 1.54 regarding Service Level I coatings inside containment.

Enhancement 1. LRA Section B2.1.33 states an enhancement to the "parameters monitored or inspected" program element. In this enhancement, the applicant stated that procedures will be enhanced to specify parameters monitored or inspected to include any visible defects, such as blistering, cracking, flaking, peeling, rusting, or physical damage. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S8 and finds it acceptable because when it is implemented it will make the program consistent with the recommendations in GALL Report AMP XI.S8.

Enhancement 2. LRA Section B2.1.33 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that the procedures will be enhanced to specify inspection frequencies, personnel qualifications, inspection plans, inspection methods, and inspection equipment that meet the requirements of ASTM D 5163-08. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S8 and finds it acceptable because when it is implemented it will make the program consistent with the recommendations in GALL Report AMP XI.S8.

Enhancement 3. LRA Section B2.1.33 states an enhancement to the "monitoring and trending" program element. In this enhancement, the applicant stated that the procedures will be enhanced to specify a pre-inspection review of the previous two monitoring reports and, based on inspection results, prioritize repair areas as either needing repair during the same outage or as postponed to future outages, but under surveillance in the interim period. The staff reviewed

this enhancement against the corresponding program element in GALL Report AMP XI.S8 and finds it acceptable because when it is implemented it will make the program consistent with the recommendations in GALL Report AMP XI.S8.

Enhancement 4. LRA Section B2.1.33 states an enhancement to the "acceptance criteria" program element. In this enhancement, the applicant stated that the procedures will be enhanced to specify characterization, documentation, and testing consistent with ASTM D 5163-08 Sections 10.2 through 10.4 and to specify an evaluation of the inspection reports by the responsible coating evaluation specialist who prepares a summary of findings and recommendations for future surveillance or repair. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S8 and finds it acceptable because GALL Report AMP XI.S8 recommends ASTM D 5163-08 as an acceptable method for characterization, documentation, and testing of Service Level I coatings, and when the enhancement is implemented it will make the program consistent with the recommendations in GALL Report AMP XI.S8.

Enhancement 5. LRA Section B2.1.33 states an enhancement to the "corrective actions" program element. In this enhancement, the applicant stated that the procedures will be enhanced to specify that the inspection reports prioritize repair areas as either needing repair during the same outage or as postponed to future outages, but under surveillance in the interim period. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S8 and finds it acceptable because GALL Report AMP XI.S8 recommends that a recommended corrective action plan be provided for defective areas, and when the enhancement is implemented it will make the program consistent with the recommendations in GALL Report AMP XI.S8.

Based on its audit of the applicant's Protective Coating Monitoring and Maintenance 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.S8. The staff also reviewed the exception associated with the "scope of program" program element and its justification and finds that the AMP, with 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," "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 B2.1.33 summarizes operating experience related to the Protective Coating Monitoring and Maintenance Program.

The applicant stated that damaged coatings were identified at several locations during the coating condition assessment of RFO 16 (fall 2008). The applicant reported that the total surface area of the degraded coatings identified was conservatively estimated at 7 square feet. The applicant stated that the damaged coatings were evaluated and removed before exiting the RFO.

The applicant stated that several areas of damaged coatings were identified during the coating condition assessment for RFO 17 (spring 2010). The applicant reported that the total surface area of the degraded coatings identified was conservatively estimated at 10 square feet. The applicant stated that the damaged coatings were removed. The applicant stated that damaged coatings were identified at several locations during the coating condition assessment of RFO 18 (fall 2011). The applicant reported that the total surface area of the degraded coatings identified

was conservatively estimated at 10 square feet. The applicant stated that the damaged coatings were evaluated and removed. The applicant also stated that the damaged coatings did not impact the results of the containment recirculation sump strainer indeterminate coatings calculation.

The staff reviewed the operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant. 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 that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.S8 was evaluated.

FSAR Supplement. LRA Section A1.33 provides the FSAR supplement for the Protective Coating Monitoring and Maintenance Program. The staff reviewed this FSAR 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. 24) to enhance the existing Protective Coating Monitoring and Maintenance Program six months before the period of extended operation for managing aging of applicable components during the period of extended operation. The staff finds that the information in the FSAR supplement, as amended by letter dated February 28, 2013, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Protective Coating Monitoring and Maintenance Program, the staff concludes 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. 24 six months before 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 FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.19 Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Summary of Technical Information in the Application. LRA Section B2.1.34 describes the existing Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program as consistent, with enhancements, with GALL Report AMP XI.E1, "Insulation Material for 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, the non-EQ cables, connections, and terminal blocks within the scope of license renewal in accessible areas are visually inspected for embrittlement, discoloration, cracking, melting, swelling, or surface 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.E1.

The staff also reviewed the portions of the "scope of program," "parameters monitored or inspected," "detection of aging effects," "acceptance criteria," and "corrective actions" program elements associated with the enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B2.1.34 states an enhancement to the "scope of program" program element. In this enhancement, the applicant stated that procedures will be enhanced to include all accessible in-scope cable in an adverse localized environment. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.E1 and finds it acceptable because when it is implemented the applicant's AMP will be consistent with the recommendations of GALL Report AMP XI.E1 for the "scope of program" program element.

Enhancement 2. LRA Section B2.1.34 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," "acceptance criteria," and "corrective actions" program elements. In this enhancement, the applicant stated that procedures will be enhanced to ensure there are no unacceptable visual indications of surface anomalies. The applicant also stated that all unacceptable visual indications of cable jacket and connection insulation surface anomalies will be subject to an engineering evaluation for "parameters monitored or inspected," "detection of aging effects," "acceptance criteria," and "corrective actions" program elements. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.E1 and finds it acceptable because when it is implemented the applicant's AMP will be consistent with the recommendations of GALL Report AMP XI.E1.

Based on its audit of the applicant's Insulation Material for Electrical Cables and Connections 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.E1. In addition, the staff reviewed the enhancements associated with the "scope of program," "parameters monitored or inspected," "detection of aging effects," "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 B2.1.34 summarizes operating experience related to the Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. The applicant stated that in 2007 an anomaly in high potential test results on phase B was noted while testing a 13.8 kV cable to a nonsafety-related 4160 V transformer. The applicant also stated that the cable had not failed and was identified for trending. In addition, the applicant stated that no instances of reduced insulation resistance in an adverse localized environment have been identified.

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 that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.E1 was evaluated.

FSAR Supplement. LRA Section A1.34 provides the FSAR supplement for the Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. The staff reviewed this FSAR 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 enhance the existing Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program six months before the period of extended operation for managing aging of applicable components during the period of extended operation. The staff finds that the information in the FSAR supplement, as amended by letter dated February 28, 2013, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Insulation Material for Electrical Cables and Connections 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. 25 six months before 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 FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.20 Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits

Summary of Technical Information in the Application. LRA Section B2.1.35, as amended by letter dated April 25, 2012, describes the existing Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program as consistent, with enhancements, with GALL Report AMP XI.E2, "Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits." The LRA states that this program manages reduced insulation resistance to ensure that cables and connections used in sensitive instrumentation circuits with high voltage low-level current signals within the ex-core neutron monitoring system are capable of performing their intended functions. The LRA also states that all high voltage cables to radiation monitors within the scope of license renewal are managed by the EQ of Electric Components Program.

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.E2.

The staff also reviewed the portions of the "scope of program," "parameters monitored or inspected," "detection of aging effects," "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 B2.1.35 states an enhancement to the "scope of program" and "acceptance criteria" program elements. In this enhancement, the applicant stated that procedures will be enhanced to identify the scope of cables requiring aging management. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.E2 and finds it acceptable because when it is implemented the applicant's AMP will be consistent with the GALL Report AMP XI.E2 "scope of program" and "acceptance criteria" program elements.

Enhancement 2. LRA Section B2.1.35, as amended by letter dated April 25, 2012, states an enhancement to the "parameters monitored or inspected" and "detection of aging effects" program elements. The applicant stated that procedures will be enhanced to require engineering review of surveillance results every 10 years. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.E2 and finds it acceptable because when it is implemented the applicant's AMP will be consistent with the GALL Report AMP XI.E2 "parameters monitored or inspected" and "detection of aging effects" program elements.

Enhancement 3. LRA Section B2.1.35, as amended by letter dated April 25, 2012, states an enhancement to the "corrective actions" program element. The applicant stated that procedures will be enhanced to ensure corrective actions are initiated when surveillance results do not meet acceptance criteria and to require an engineering evaluation be performed. When an unacceptable condition or situation is identified, a determination is also made as to whether the review of surveillance results or the cable testing frequency needs to be increased. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.E2 and finds it acceptable because when it is implemented the applicant's AMP will be consistent with the GALL Report AMP XI.E2 "corrective actions" program element.

Based on its audit of the applicant's Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits 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.E2. In addition, the staff reviewed the enhancements associated with the "scope of program," "parameters monitored or inspected," "detection of aging effects," "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 B2.1.35 summarizes operating experience related to the Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program. In CAR No. 200404746, the applicant stated that signal noise was found on signal cable B on channel N61. The channel consists of two fission chambers in one detector housing with two

signal cables. Testing of the system identified high noise on signal cable B and the applicant determined that a bad solder joint created the bad cable connection. The applicant took corrective action to pull the new cable.

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 that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.E2 was evaluated.

FSAR Supplement. LRA Section A1.35 provides the FSAR supplement for the Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program. The staff reviewed this FSAR 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 enhance the existing Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program six months before the period of extended operation for managing aging of applicable components during the period of extended operation. The staff finds that the information in the FSAR supplement, as amended by letters dated April 25, 2012, and February 28, 2013, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits 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. 26 six months before 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 FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.21 Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Summary of Technical Information in the Application. LRA Section B2.1.36, as amended by letters dated April 25, 2012, and August 9, 2012, describes the existing Inaccessible Power 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 LRA states that the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program manages reduced insulation resistance of power cables (greater than or equal to 400 V) to minimize aging effects that could potentially lead to failure of the cable's insulation system. The LRA states that the program provides reasonable assurance that the intended functions of inaccessible or underground power cables exposed to wetting or submergence are maintained consistent with the CLB through the period of extended operation. The LRA also states that manholes, pits, and duct banks that contain in-scope non-EQ inaccessible power cables will be inspected for water collection. In addition, the LRA states that the inspection will include direct observation that the cables are not submerged or immersed in water, cables/splices and support structures are intact, and dewatering/drainage systems (i.e., sump pumps) and associated alarms operate properly. Inspection and water removal is performed based on plant experience with an inspection frequency of at least annually and after event-driven occurrences (such as heavy rain or flooding). In addition, operation of dewatering devices will be inspected before any known or predicted heavy rain or flooding events. The LRA further states that the first inspection for license renewal is to be completed before the period of extended operation. Finally, the LRA states that in-scope inaccessible power cables will be tested to provide an indication of the conductor insulation condition with the first tests for license renewal completed before the period of extended operation and every 6 years thereafter.

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," "detection of aging effects," and "corrective actions" program elements, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

The "scope of program" program element in GALL Report AMP XI.E3 recommends a voltage level of greater than or equal to 400 V. However, during its audit, the staff found that the applicant's "scope of program" program element of basis document CW-AMP-B2.1.36, "Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," does not indicate the voltage level of in-scope inaccessible power cable (i.e., greater than or equal to 400 V). Additionally, LRA FSAR supplement A1.36 and LRA Appendix A, Table A4-1, "License Renewal Commitments," do not specify inaccessible power cable voltage level.

By letter dated July 9, 2012, the staff issued RAI B2.1.36-1 requesting that the applicant explain why the "scope of program" program element for basis document CW-AMP-B2.1.36, Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements, LRA Section A1.36, "Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," and LRA Table A4-1, "License Renewal Commitments," do not reference in-scope inaccessible power cable voltage level (greater than or equal to 400 V).

In its response dated August 9, 2012, the applicant stated that LRA Table A4-1 item 27, LRA Section A1.36, and the enhancement to "scope of program" program element in LRA Section B2.1.36, have been revised as shown by LRA Amendment 6 to indicate that in-scope non-EQ inaccessible power cables are greater than or equal to 400 V. The applicant also

stated that it revised basis document CW-AMP-B2.1.36 to indicate that in-scope non-EQ inaccessible power cables are greater than or equal to 400 V.

The staff finds the applicant's response acceptable because all of the aforementioned documents in question were revised by the applicant to indicate in-scope inaccessible power cable voltage level as greater than or equal to 400 V consistent with the recommendations of GALL Report AMP XI.E3. The staff's concern described in RAI B2.1.36-1 is resolved.

GALL Report AMP XI.E3 recommends that periodic actions be taken to prevent inaccessible power 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 "scope of program" program element of the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program does not include in-scope manholes MH59-8A and MH59-8B.

By letter dated July 9, 2012, the staff issued RAI B2.1.36-2 requesting that the applicant explain why in-scope manholes MH59-8A and MH59-8B are not included in the "scope of program" program element of its Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program.

In its response dated August 9, 2012, the applicant stated that "basis document CW-AMP B2.1.36, Element 3.1, Scope of Program, has been revised to include MH59-8A and MH59-8B."

The staff finds the applicant's response acceptable because the basis document CW-AMP-B2.1.36 was revised to include all in-scope manholes consistent with the recommendations of GALL Report AMP XI.E3. The staff's concern described in RAI B2.1.36-2 is resolved.

The "detection of aging effects" program element in GALL Report AMP XI.E3 recommends that power cables exposed to significant moisture be tested at least once every 6 years and be adjusted based on test results (including trending of degradation where applicable) and operating experience. However, during its audit, the staff found that the applicant's "detection of aging effects" program element of its Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, draft procedure EDP-ZZ-07001, and LRA Section A1.36 do not state that test frequencies are adjusted based on test results as well as operating experience.

By letter dated July 9, 2012, the staff issued RAI B2.1.36-4 requesting that the applicant explain why the "detection of aging effects" program element of basis document CW-AMP-B2.1.36, LRA Section A1.36, and draft procedure EDP-ZZ-07001 do not include adjusting test frequencies based on test results and operating experience consistent with the recommendations in GALL Report AMP XI.E3 "detection of aging effects" program element.

In its response dated August 9, 2012, the applicant stated that LRA Sections A1.36, B2.1.36, and LRA Table A4-1 item 27 have been revised as shown by LRA Amendment 6 to read "[t]he first test for license renewal will be completed before the period of extended operation with subsequent tests performed at least every [6] years thereafter and adjusted based on test results and operating experience." The applicant also stated that basis document CW-AMP-B2.1.36, "detection of aging effects" program element and draft procedure

EDP-ZZ-07001 paragraphs 4.1.8 and 4.1.9 have been enhanced to state that the frequency of inspection and test is "…adjusted based on test results and operating experience…"

The staff finds the applicant's response acceptable because all of the aforementioned documents in question were revised consistent with the recommendations in GALL Report AMP XI.E3 "detection of aging effects" program element. The staff's concern described in RAI B2.1.36-4 is resolved.

During the audit the staff found that draft procedure EDP-ZZ-07001 Section 2.0, "Scope," states that Table 2, "Underground Cable Requiring Aging Management," lists the inaccessible power cables not subject to EQ requirements and within the scope of license renewal aging management. Table 2 lists additional cables not in-scope of basis document CW-AMP-B2.1.36 or the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. Additionally, in-scope cable CA-3331L2 is duplicated in Table 2 with different routing.

By letter dated July 9, 2012, the staff issued RAI B2.1.36-6 requesting that the applicant reconcile Table 2 and Section 2, "Scope," descriptions. The staff also requested the applicant to identify cables in-scope of license renewal and associated AMPs, including the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program (GALL Report AMP XI.E3) in Table 2. In addition, the staff requested the applicant to provide clarification on duplicate cable listing for CA-3331L2 in Table 2.

In its response dated August 9, 2012, the applicant stated that Procedure EDP-ZZ-07001 has been revised to include the following:

- Section 2.0 third paragraph states: "Table 2 lists underground cable requiring aging management"
- [a]dded column to Table 2 enhancement to identify whether the cable will be managed by XI.E1 or XI.E3
- [r]evised Table 2 to reflect Cable CA-3331L2 is routed from MH59-1A, through MH59-4, and to MH59-5

The staff finds the applicant's response acceptable because the differences in the two documents for in-scope cables have been reconciled. Additionally, the applicant provided the requested clarification to the duplicate cable listing. The staff's concern described in RAI B2.1.36-6 is resolved.

The "corrective actions" program element in GALL Report AMP XI.E3 recommends corrective actions are taken and an engineering evaluation is performed when the test or inspection acceptance criteria are not met. However, during its audit, the staff found that the applicant's draft procedure EDP-ZZ-07001, Section 4.2.3, states that appropriate corrective actions shall be taken if significant aging that results from adverse environments is identified or suspected. The corrective action is not consistent with the GALL Report AMP XI.E3 "corrective actions" program element or basis document CW-AMP-B2.1.36.

By letter dated July 9, 2012, the staff issued RAI B2.1.36-7 requesting that the applicant explain why the corrective actions as described in draft procedure EDP-ZZ-07001, Section 4.2.3, are not consistent with GALL Report AMP XI.E3.

In its response dated August 9, 2012, the applicant stated that "[p]aragraph 4.2.6 of procedure EDP-ZZ-07001 markup was redundant to paragraph 4.3.10, which is cited in basis document CW-AMP B2.1.36, Element 7, Corrective Actions." The applicant also stated that procedure EDP-ZZ-07001 markup has been revised to remove the redundancy in paragraph 4.2.6, and corrective actions remain in paragraph 4.3.10 as described in the basis document.

The staff finds the applicant's response acceptable because procedure EDP-ZZ-07001 was revised consistent with the applicant's basis document and the recommendations in the GALL Report AMP XI.E3 "corrective actions" program element. The staff's concern described in RAI B2.1.36-7 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," "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 B2.1.36, as amended by letters dated April 25, 2012, and August 9, 2012, states an enhancement to the "scope of program" program element. In this enhancement, the applicant stated that procedures will be enhanced to identify the power cables (greater than or equal to 400 V), manholes, pits, and duct banks that are within the scope of the Inaccessible Power 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 acceptable because when it is implemented it will be consistent with the recommendations of GALL Report AMP XI.E3 "scope of program" program element with regard to identification of in-scope inaccessible power cables.

Enhancement 2. LRA Section B2.1.36, as amended by letters dated April 25, 2012, and August 9, 2012, states an enhancement to the "preventive actions" program element. In this enhancement, the applicant stated that procedures will be enhanced to include periodic inspection of manholes, pits, and duct banks and to confirm (1) cables are not submerged or immersed in water, (2) cables/splices and cable support structures are intact, and (3) dewatering/drainage systems (i.e., sump pumps) and associated alarms operate properly. The applicant stated that inspections will be performed at least annually based on water accumulation over time and after event-driven occurrences (e.g., heavy rain or flooding). The applicant also stated that operation of dewatering devices will be inspected and confirmed before any known or predicted heavy rain or flooding events. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.E3 and finds it acceptable because when it is implemented it will be consistent with the recommendations of the GALL Report AMP XI.E3 "preventive actions" program element.

Enhancement 3. LRA Section B2.1.36, as amended by letters dated April 25, 2012, and August 9, 2012, states an enhancement to the "parameters monitored or inspected" program element. In this enhancement, the applicant stated that procedures will be enhanced to confirm cables are not submerged or immersed in water, cable/splices and cable support structures are intact, dewatering/drainage systems (i.e., sump pumps) and associated alarms operate properly, and power cables subject to significant moisture are tested periodically. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.E3 and finds it acceptable because when it is implemented it will be consistent with the

recommendations of the GALL Report AMP XI.E3 “parameters monitored or inspected” program element.

Enhancement 4. LRA Section B2.1.36, as amended by letters dated April 25, 2012, and August 9, 2012, states an enhancement to the “detection of aging effects” program element. In this enhancement, the applicant stated that procedures will be enhanced to ensure that in-scope power cables are tested at least once every 6 years and adjusted based on test results and operating experience. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.E3 and finds it acceptable because when it is implemented it will be consistent with the recommendations of the GALL Report AMP XI.E3 “detection of aging effects” program element.

Enhancement 5. LRA Section B2.1.36, as amended by letters dated April 25, 2012, and August 9, 2012, states an enhancement to the “monitoring and trending” program element. In this enhancement, the applicant stated that procedures will be enhanced to require comparing results to previous test results to evaluate for additional information on the rate of cable degradation. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.E3 and finds it acceptable because when it is implemented it will be consistent with the recommendations of the GALL Report AMP XI.E3 “monitoring and trending” program element.

Enhancement 6. LRA Section B2.1.36, as amended by letters dated April 25, 2012, and August 9, 2012, states an enhancement to the “acceptance criteria” program element. In this enhancement, the applicant stated that procedures will be enhanced to confirm cables are not submerged or immersed in water, cable/splices and cable support structures are intact, and dewatering/drainage systems (i.e., sump pumps) and associated alarms operate properly. The applicant also stated that acceptance criteria for cable testing will be defined before each test. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.E3 and finds it acceptable because when it is implemented it will be consistent with the recommendations of the GALL Report AMP XI.E3 “acceptance criteria” program element.

Enhancement 7. LRA Section B2.1.36, as amended by letters dated April 25, 2012, and August 9, 2012, 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 when the test or inspection acceptance criteria are not met. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.E3 and finds it acceptable because when it is implemented it will be consistent with the recommendations of the GALL Report AMP XI.E3 “corrective action” program element.

Based on its audit of the applicant’s Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program and review of the applicant’s responses to RAIs B2.1.36-1, B2.1.36-2, B2.1.36-4, B2.1.36-6, and B2.1.36-7, 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.E3. 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,” “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 B2.1.36, as amended by letters dated April 25, 2012, and August 9, 2012, summarizes operating experience related to the Inaccessible Power Cables Not

Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. The applicant stated that it had been performing inspections of safety-related manhole MH01 on a 36-month frequency. The applicant stated that water was found in MH01 in 2003 and 2009 with water being below medium-voltage safety-related cables and in 2006 with all cables submerged. The applicant determined that the manhole cover seals were degraded. The applicant also stated that corrective actions included (1) new seals being installed since 2009 after each inspection of MH01, (2) inspection frequency for MH01 was changed from 36 to 6 months, and (3) foundation sealant, drain pipes, and flashing were installed for MH01 in 2010. The applicant further stated that the as-found water level for MH01A dropped from 30 to 15 in. and from 24 to 2 in. for MH01B. The applicant stated that the existing program tests cable periodically with no degradation of safety-related cables noted. In addition, the applicant implemented new preventive maintenance in 2011 to inspect for water level and pump out all in-scope manholes weekly. The applicant further stated that a modification to install sump pumps in all in-scope manholes is currently underway with five manholes completed as of March 12, 2012. The applicant noted that operating experience with the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program has not identified any cable failures as a result of submergence.

The staff also reviewed recent integrated inspection reports (January 20, 2010, January 26, 2011, May 4, 2011, July 18, 2011, and August 24, 2011). No findings were noted for manholes or cable submergence. In addition, during the audit the staff conducted walkdowns of in-scope manholes MH59-31, MH59-01A, MH59-01B, MH59-12, MH59-20, MH59-19, and switchyard control house cable pit 2 confirming locations, labeling, cover integrity, and susceptibility to surface water runoff. The staff noted that manhole MH59-12 with sump pump installed was opened for inspection with no issues noted. The staff reviewed corrective action reports documenting manhole inspection findings and corrective action taken, including water removal, revised inspection frequencies, cable test guidance, and the development of a modification package and associated work orders to install sump pumps in in-scope manholes.

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 reviewed the applicant's response to GL 2007-01, "Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients," which requested, in part, that applicants provide a history of inaccessible or underground power cable failures. The applicant's response stated that one failure of a 480 V AC power cable within the scope of 10 CFR 50.65 was noted (voltage range of 480 V AC to 1.5 kV AC). A definitive root cause for the failure was not determined by the applicant. Cable damage during installation leading to eventual failure was suspected based on the replacement cable being in service for 17 years. Although CAR 201008001 was written to address the lack of a medium voltage cable strategy at Callaway and not a specific cable failure, the staff noted during the audit that CAR 201008001 also states that some cable failures at Callaway were attributed to water submergence.

By letter dated July 9, 2012, the staff issued RAI B2.1.36-5 requesting that the applicant describe the cable failures at Callaway that have been attributed to submergence and describe any changes to the existing program as a result of operating experience gained from these failures.

In its response dated August 9, 2012, the applicant stated that after the audit a search for cable failures at Callaway confirmed that no cable failures that could be directly attributed to water submergence have occurred and, therefore, the statement in CAR 201008001 was inaccurate. The applicant stated that the inaccuracy in CAR 201008001 was entered as an adverse condition into the Callaway CAP and as corrective action, to verify that there have been no cable failures at Callaway attributed to submergence, an independent document review was conducted and the text in CAR 201008001 was revised to remove the inaccurate statement. The applicant also stated that its response to GL 2007-01 and the discussion of plant operating experience for the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program correctly state that operating experience with the existing program did not identify any cable failures attributed to submergence or water intrusion.

The staff finds the applicant's response acceptable because the applicant resolved the inaccuracy in CAR 201008001 by taking corrective actions which consisted of performing an independent review that confirmed no cable failures directly attributed to water submergence have occurred at Callaway and revising the text in the CAR to remove the inaccurate statement. The staff's concern described in RAI B2.1.36-5 is resolved.

Based on its audit and review of the application, and review of the applicant's response to RAI B2.1.36-5, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.E3 was evaluated.

FSAR Supplement. LRA Section A1.36 provides the FSAR supplement for the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. The staff reviewed this FSAR 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 enhancements listed in LRA Table A4-1, Commitment No. 27, and the AMP description in LRA Section A1.36, are not in agreement. Specifically, LRA Table A4-1 includes enhancements that state the following but are not addressed in LRA Section A1.36.

- operation of dewatering devices will be inspected and confirmed before any known or predicted heavy rain or flooding events
- test results will be compared to previous test results to evaluate for additional information on the rate of cable degradation
- acceptance criteria for cable testing will be defined before each test
- an engineering evaluation will be required when the test or inspection acceptance criteria are not met

The licensing basis for this program for the period of extended operation may not be adequate if the applicant does not incorporate this information into its FSAR supplement (LRA Section A1.36). By letter dated July 9, 2012, the staff issued RAI B2.1.36-3 requesting that the applicant explain why the above enhancements described in LRA Table A4-1, Commitment

No. 27 are not included LRA Section A1.36 consistent with the recommendations in GALL Report AMP XI.E3.

In its response dated August 9, 2012, the applicant stated that LRA Section A1.36 has been revised as shown by LRA Amendment 6 and basis document CW-AMP-B2.1.36 has been revised to include:

- test results will be compared to previous test results to evaluate for additional information on the rate of cable degradation
- acceptance criteria for cable testing will be defined before each test
- an engineering evaluation is required when the test or inspection acceptance criteria are not met

The staff also noted that by letter dated April 25, 2012, the applicant revised LRA Section A1.36 to include the following: "[d]ewatering devices will be inspected and operation confirmed before any known or predicted heavy rain or flooding events."

The staff finds the applicant's response acceptable because LRA Section A1.36 and basis document CW-AMP-B2.1.36 have been revised and are consistent with each other and the recommendations in GALL Report AMP XI.E3. Therefore, the FSAR supplement for the Inaccessible Power 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 concern described in RAI B2.1.36-3 is resolved.

The staff also noted that the applicant committed (Commitment No. 27) to enhance the existing Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program six months before the period of extended opertion for managing aging of applicable components during the period of extended operation. The staff finds that the information in the FSAR supplement, as amended by letters dated April 25, 2012, August 9, 2012, and February 28, 2013, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Inaccessible Power 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. 27 six months before 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 FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.22 Fatigue Monitoring

Summary of Technical Information in the Application. LRA Section B3.1 describes the existing Fatigue Monitoring Program as consistent, with enhancements, with GALL Report AMP X.M1, "Fatigue Monitoring." The LRA states that the program manages fatigue cracking caused by anticipated cyclic strains in metal components of the RCPB. The LRA also states that the Fatigue Monitoring Program ensures that actual plant experience remains bounded by the

thermal and pressure transient numbers and severities analyzed in the design calculations; otherwise, corrective actions are taken to maintain the design and licensing basis. The LRA further states that the Fatigue Monitoring Program tracks fatigue by one of the following methods: (1) the cycle counting monitoring method, (2) the cycle-based fatigue (CBF) monitoring method, and (3) the stress-based fatigue (SBF) monitoring method. In addition, the LRA states that the program will be enhanced to include environmentally-assisted fatigue (EAF) for a set of RCS sample locations, which includes fatigue monitoring of the NUREG/CR-6260 sample locations for a newer-vintage Westinghouse Plant and plant-specific bounding EAF locations. The LRA also states that the supporting environmental factors calculations will be performed with NUREG/CR-6909 or NUREG/CR-6583 for carbon and low-alloy steels, NUREG/CR-6909 or NUREG/CR-5704 for austenitic stainless steels, and NUREG/CR-6909 for nickel alloys.

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.M1.

The staff noted that LRA Section 4.3.1.1 provides additional details on the Fatigue Monitoring Program's monitoring methods. Specifically, it states that the cycle counting monitoring method tracks transient event cycles affecting the location to ensure that the number of transient events analyzed by the design calculations are not exceeded. The staff noted that this method relies on ensuring that the actual severity of transients is less than the design severity in order to count the number of design transient cycles, which is discussed in Enhancement 2. The staff finds it conservative that the applicant records transients as full design transient cycles because the severity of actual transients is typically less than the design transient definition; thus, this equates to a lower actual accumulated fatigue usage when compared to the design assumption. The staff noted that this method compares the numbers of cycles that have occurred to the corresponding allowable values used in associated fatigue analyses. The staff finds the use of cycle counting to be capable of managing metal fatigue because it ensures that the assumptions used in a fatigue evaluation remain valid, thus, ensuring the design limit is not exceeded.

Furthermore, LRA Section 4.3.1.1 states that the CBF monitoring method uses the cycle counting results and stress intensity ranges generated with the ASME Code Section III methods to perform CUF calculations for a given location, and the fatigue accumulation is tracked to determine if the ASME Code allowable fatigue limit of 1.0 is approached. The staff noted that the applicant's program includes corrective actions that address the issue when actual transient severity exceeds design transient severity, which is consistent with the "detection of aging effects" program element of GALL Report AMP X.M1. The staff finds the use of CBF 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 through the period of extended operation.

Finally, LRA Section 4.3.1.1 states that the SBF monitoring method computes a "real time" stress history for a given component from data collected by plant instruments to calculate transient pressure and temperature and the corresponding stress history at the critical location in the component. The staff noted that the use of actual plant data such as local pressure and thermal conditions to calculate actual fatigue usage is consistent with the "parameters monitored or inspected" program element of GALL Report AMP X.M1 for more "detailed monitoring." The staff finds the use of SBF monitoring to be capable of managing metal fatigue because it periodically calculates cumulative fatigue usage based on the conditions that are

actually occurring at the applicant's site during transients to ensure the design limit is not exceeded through the period of extended operation.

The staff also reviewed the portions of the "scope of program," "preventive actions," "parameters monitored or inspected," "monitoring and trending," "acceptance criteria," and "corrective actions" program elements associated with the enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B3.1 states an enhancement to the "scope of program" program element. In this enhancement, as amended by letter dated October 17, 2013, the applicant stated that procedures will be enhanced to include fatigue usage calculations that consider the effects of the reactor water environment for a set of sample reactor coolant pressure boundary locations and reactor vessel internals locations with fatigue usage calculations. The reactor coolant pressure boundary set includes the NUREG/CR-6260 sample locations for a newer-vintage Westinghouse Plant, and plant-specific bounding EAF locations. The enhancement also states that procedures will be enhanced to ensure that the fatigue crack growth analyses, which support the leak-before-break (LBB) analyses, ASME Code Section XI evaluations, and the high-energy line break (HELB) selection criterion, remain valid by counting the transients used in the analyses.

The "scope of program" program element of GALL Report AMP X.M1 states for purposes of monitoring and tracking applicants should include, for a set of sample RCS components, fatigue usage calculations that consider the effects of the reactor water environment. This sample set is to include the locations identified in NUREG/CR-6260 and additional plant-specific component locations in the RCPB if they may be more limiting than those considered in NUREG/CR-6260. Consistent with the recommendations of GALL Report AMP X.M1, the applicant proposed to enhance its program to address EAF for the NUREG/CR-6260 sample locations for a newer-vintage Westinghouse Plant and plant-specific bounding EAF locations. The staff's review of the applicant's evaluation of the NUREG/CR-6260 sample locations for a newer-vintage Westinghouse Plant and the methodology to identify plant-specific bounding EAF locations is documented in SER Section 4.3.4.2. The staff noted that in response to Applicant/Licensee Action Item No.8, Item 5, to MRP-227-A, the applicant is also addressing the effects of reactor water environment on reactor vessel internals locations with fatigue usage calculations. The staff noted that, regardless of whether the components are reactor coolant pressure boundary or reactor vessel internals, they are both exposed to the same water environment and are impacted by environmentally assisted fatigue. Thus, the staff finds it appropriate and acceptable that the reactor vessel internal locations are included into the Fatigue Monitoring Program for consideration and aging management of environmentally assisted fatigue.

The staff noted that the applicant also proposed to include fatigue crack growth analyses, which support the LBB analyses, ASME Code Section XI evaluations, and the HELB break selection criterion, within the scope of its Fatigue Monitoring Program during the period of extended operation. Since this portion of the applicant's enhancement is beyond the recommendations of GALL Report AMP X.M1, the staff's review was performed in accordance with SRP-LR Section A.1.2.3.1, "Scope of Program," which states that the scope of the program should include the specific SCs for which program manages aging. The staff noted that these analyses use the same design transients monitored by the cycle counting monitoring method of the program. The staff finds the use of the cycle counting method for these analyses appropriate because it will ensure that corrective actions are taken before any assumptions used in these

analyses have the possibility of becoming invalid. The staff's review of each method is described above.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP X.M1 and finds it acceptable because, when it is implemented, the applicant will have addressed EAF for the NUREG/CR-6260 locations and potential additional plant-specific component locations consistent with the GALL Report. In addition, as described above, the staff finds it acceptable that the applicant includes reactor vessel internal locations with fatigue usage calculations in the Fatigue Monitoring Program for aging management of environmentally assisted fatigue. The staff also finds this enhancement acceptable because, consistent with SRP-LR Section A.1.2.3.1, the Fatigue Monitoring Program specifically identifies the additional analyses that will be added to the Fatigue Monitoring Program and also includes measures, as described above, of ensuring that the assumptions used in these fatigue crack growth analyses remain valid during the period of extended operation; otherwise, corrective actions will be taken.

Enhancement 2. LRA Section B3.1 states an enhancement to the "preventive actions" program element. In this enhancement, the applicant stated that procedures will be enhanced to require the review of the temperature and pressure transient data from the operator logs and plant instrumentation to ensure actual transient severity is bounded by the design and to include environmental effects where applicable. Furthermore, if a transient occurs that exceeds the design transient definition, the event is documented in the CAP, and corrective actions are taken.

The "preventive actions" program element of GALL Report AMP X.M1 states that the program prevents the fatigue TLAAs from becoming invalid by ensuring that the fatigue usage resulting from actual operational transients does not exceed the code design limit of 1.0, including environmental effects where applicable. Furthermore, this could be caused by the numbers of actual plant transients exceeding the numbers used in the fatigue analyses or by the actual transient severity exceeding the bounds of the design transient definitions.

The staff noted that the applicant's program is existing, which has been monitoring transients since initial plant startup, and that an essential part of a fatigue management program is to ensure that the design severity of a transient is not exceeded during plant operation. Therefore, considering that there is this enhancement to the program, it is not clear to the staff how the applicant ensures accumulated transients from initial plant startup will be bounded by the design transients before procedure enhancement.

By letter dated June 22, 2012, the staff issued RAI B3.1-1 requesting the applicant to explain how the existing program ensures that transients from initial plant startup are either bounded by the design transient or accurately captured by the Fatigue Monitoring Program. In addition, the applicant was requested to justify the purpose of the enhancement if the existing program already includes provisions for comparing transient severity between actual and design transients.

In its response dated July 20, 2012, the applicant stated that the RCPB components are designed to withstand the operating transients as defined in FSAR Section 3.9(N).1.1 and the system specifications. The applicant stated that the plant operating procedures and technical specifications are designed to ensure that the severity of plant events is bounded by those described in the design analyses (e.g., maximum rates of change of temperatures, pressures, flows) and that the existing Fatigue Monitoring Program requires a review of the design transient tracking log at least once per cycle to ensure that components are maintained within their

design limits. The applicant also confirmed that this review draws on multiple data sources (e.g., CAP, plant computer, operator logs/rounds, strip charts, and FatiguePro data) to assure that the actual transients have been appropriately characterized and are bounded by the design transients. The applicant further stated that if a thermal or pressure transient occurs that is not bounded by the design transient, the event is documented in the CAP and an engineering evaluation is performed to determine the impact on applicable components and analyses.

The staff finds this approach by the existing Fatigue Monitoring Program appropriate because the applicant periodically ensures that design limits are not exceeded by reviewing information from, but not limited to, the plant computer, operator logs, and strip charts to characterize actual plant transients. Thus, the applicant's existing program includes this fundamental aspect of a fatigue monitoring program. The applicant stated that the existing program already includes provisions for comparing severity between actual transients and design transients and that the enhancement was added to document the process within the procedure.

The staff finds the applicant's response to RAI B3.1-1 acceptable because the Fatigue Monitoring Program already includes provisions for comparing design and actual transient severity, which ensures an accurate cycle count through the period of extended operation, and the applicant confirmed that the enhancement is only meant for a programmatic update of its procedures. The staff's concern described in RAI B3.1-1 is resolved.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP X.M1 and finds it acceptable because when it is implemented the applicant's Fatigue Monitoring Program will procedurally document provisions for comparing design and actual transient severity to ensure the bounds of the design transient definitions are not exceeded and will be consistent with the recommendations of GALL Report AMP X.M1.

Enhancement 3. LRA Section B3.1 states an enhancement to the "parameters monitored or inspected" program element. In this enhancement, the applicant stated that procedures will be enhanced to include additional transients that contribute significantly to fatigue usage identified by evaluation of ASME Code Section III fatigue and fatigue crack growth analyses. The enhancement, as amended by letter dated October 17, 2013, also states that procedures will be enhanced to include additional locations that receive more detailed monitoring. These locations were identified by evaluation of ASME Section III fatigue analyses and the locations evaluated for effects of the reactor water environment. In addition, reactor vessel internals locations with fatigue usage calculations will be evaluated for the effects of the reactor water environment. Furthermore, the monitoring methods will be benchmarked consistent with NRC RIS 2008-30, "Fatigue Analysis of Nuclear Power Plant Components."

The "parameters monitored or inspected" program element of GALL Report AMP X.M1 states that the program monitors all plant design transients that cause cyclic strains, which are significant contributors to the fatigue usage factor. Furthermore, the number of occurrences of the plant transients that cause significant fatigue usage for each component is to be monitored. Alternatively, more detailed monitoring of local pressure and thermal conditions may be performed to allow the actual fatigue usage for the specified critical locations to be calculated.

The staff noted that the applicant proposed to identify additional transients that were included in fatigue crack growth analyses, which support the LBB analyses, ASME Code Section XI evaluations, and the HELB break selection criterion. Since this portion of the applicant's enhancement is beyond the recommendations of GALL Report AMP X.M1, the staff's review was performed in accordance with SRP-LR Section A.1.2.3.3, "Parameters Monitored or Inspected," which states the aging effects that the program manages are identified and linked

between the parameter(s) that will be monitored and how the monitoring of these parameters will ensure adequate aging management. The staff noted that the specific aging effects evaluated in these fatigue crack growth analyses will be managed by the Fatigue Monitoring Program because the program ensures that the assumptions used in these analyses remain valid during the period of extended operation; otherwise, corrective actions are taken.

The staff noted that this enhancement implies that the evaluation to identify additional transients that contribute significantly to fatigue usage of ASME Code Section III fatigue and used in fatigue crack growth analyses will be completed in the future. However, LRA Section 4.3.1 states that LRA Table 4.3-2 lists the transients that the Fatigue Monitoring Program monitors. In addition, it states that the transients included in the program were identified through a review of the design and licensing analyses. Based on LRA Section 4.3.1, it seems that a review of the design and licensing analyses has already been performed; therefore, it is not clear to the staff what will be enhanced in the procedures. By letter dated June 22, 2012, the staff issued RAI B3.1-2 requesting the applicant to clarify the discrepancy between LRA Section B3.1 and LRA Section 4.3.1 and the actions associated with this enhancement to the procedures to include additional transients that contribute significantly to fatigue usage identified by evaluation of ASME Code Section III fatigue and fatigue crack growth analyses.

In its response dated July 20, 2012, the applicant stated that the review and evaluation of ASME Code Section III fatigue and fatigue crack growth analyses to identify transients that contribute significantly to fatigue usage has been completed. In addition, the applicant clarified that this enhancement in LRA Section B3.1 requires incorporation of transients that contribute significantly to fatigue usage into the Fatigue Monitoring Program and that a revision to the LRA was provided by letter dated June 5, 2012. The applicant stated that implementing procedures will be revised to require cycle counting of transients that contribute significantly to fatigue usage into the Fatigue Monitoring Program.

The staff reviewed the revision made by letter dated June 5, 2012, to clarify the discrepancy identified in RAI B3.1-2. As a result, the staff finds the applicant's response to RAI B3.1-2 acceptable because it was clarified that the review to identify transients that contribute significantly to fatigue usage has been completed and that this enhancement is a programmatic update of procedures. In addition, the staff finds the response acceptable because the review to identify these additional transients is consistent with the recommendations of GALL Report AMP X.M1 and ensures that the transient assumptions used in ASME Code Section III fatigue and fatigue crack growth analyses will remain valid through the period of extended operation. The staff's concern described in RAI B3.1-2 is resolved.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP X.M1 and finds it acceptable because when it is implemented the applicant's Fatigue Monitoring Program will ensure the tracking of all transients that contribute significantly to fatigue usage, including EAF for reactor coolant pressure boundary components and reactor vessel internal components with fatigue usage calculations. In addition, the staff finds the applicant's enhancement acceptable because, when implemented, it will specifically identify those locations that will receive more detailed fatigue monitoring, which is consistent with the GALL Report. Furthermore, the staff finds the applicant's enhancement acceptable because, consistent with SRP-LR Section A.1.2.3.3, the program will also ensure the tracking of all transients used as assumptions in fatigue crack growth analyses to confirm their validity during the period of extended operation.

Enhancement 4. LRA Section B3.1 states an enhancement to the "monitoring and trending" program element. In this enhancement, the applicant stated that procedures will be enhanced to project the transient count and fatigue accumulation of monitored components into the future.

The "monitoring and trending" program element of GALL Report AMP X.M1 states that trending is assessed to ensure that the fatigue usage factor remains below the design limit during the period of extended operation, thus minimizing fatigue cracking of metal components caused by anticipated cyclic strains in the material.

The staff noted that trending of cycle counts and fatigue usage ensure that there is an ample amount of time for corrective actions to be taken to ensure that the cycle count limits and fatigue usage limits are not exceeded. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP X.M1 and finds it acceptable because when it is implemented the Fatigue Monitoring Program will be consistent with the GALL Report. In addition, it provides ample time for the applicant to take corrective actions when the trending of transient counts and fatigue accumulation exceed the established action limits to ensure that the cycle count limits and fatigue usage limits are not exceeded.

The staff noted that the applicant included an enhancement to the "acceptance criteria" program element to include cycle count and fatigue usage action limits to initiate corrective actions if the design limits are expected to be exceeded within the next three fuel cycles. The staff's evaluation of this enhancement to the "acceptance criteria" program element is discussed below.

Enhancement 5. LRA Section B3.1 states an enhancement to the "acceptance criteria" program element. In this enhancement, the applicant stated that procedures will be enhanced to include additional cycle count and fatigue usage action limits, which permit completion of corrective actions if the design limits are expected to be exceeded within the next three fuel cycles. The applicant also stated that the fatigue results associated with the NUREG/CR-6260 sample locations for a newer vintage Westinghouse plant and plant-specific bounding EAF locations will account for environmental effects on fatigue. The applicant further stated that the cycle count action limits for the hot-leg surge nozzle will incorporate the 60-year cycle projections used in the hot-leg surge nozzle EAF analysis.

The "acceptance criteria" program element of GALL Report AMP X.M1 states 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 described in the program description and scope of program.

The staff noted that establishing action limits provides the applicant sufficient time for activities such as resource use and planning future activities to ensure that corrective actions will be completed before the design limits, including EAF results, are exceeded. The staff finds that setting the action limit for both cycle counts and fatigue usage, such that actions are taken if the design limits are expected to be exceeded within the next three fuel cycles, to be conservative.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP X.M1 and finds it acceptable because when it is implemented the applicant's Fatigue Monitoring Program will establish action limits to ensure corrective actions are taken before a design limit, including EAF results, is exceeded during the period of extended operation, which is consistent with the GALL Report.

Enhancement 6. LRA Section B3.1 states an enhancement to the "corrective actions" program element. In this enhancement, the applicant stated that procedures will be enhanced to include appropriate corrective actions to be invoked if a component approaches a cycle count or CUF action limit or if an experienced transient exceeds the design transient definition. In addition, if an action limit is reached, corrective actions include fatigue reanalysis, repair, or replacement. The enhancement also stated that when a cycle counting action limit is reached, action will be taken to ensure that the analytical bases of the HELB locations are maintained. Furthermore, 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 "corrective actions" program element of GALL Report AMP X.M1 states that the program provides for corrective actions to prevent the usage factor from exceeding the design code limit during the period of extended operation. Furthermore, acceptable corrective actions include repair of the component, replacement of the component, and a more rigorous analysis of the component to demonstrate that the design code limit will not be exceeded during the period of extended operation.

The staff noted that the applicant proposed to include fatigue crack growth analyses, which support the LBB analyses, ASME Code Section XI evaluations, and the HELB break selection criterion. Since this portion of the applicant's enhancement is beyond the recommendations of GALL Report AMP X.M1, the staff's review was performed in accordance with SRP-LR Section A.1.2.3.7, "Corrective Actions," which states that actions to be taken when the acceptance criteria are not met should be described in appropriate detail and if corrective actions permit analysis without repair or replacement, the analysis should ensure that the structure- and component-intended function(s) are maintained consistent with the CLB.

The staff noted that the applicant's enhancement to the Fatigue Monitoring Program includes the specific corrective actions recommended in the GALL Report AMP X.M1, which include fatigue reanalysis, repair, or replacement. However, the staff also noted that Appendix B to 10 CFR Part 50 requires measures to be taken to ensure that the cause of the condition is determined and corrective action is taken to preclude repetition. Thus, the corrective actions that may be implemented in accordance with the Fatigue Monitoring Program are not limited to fatigue reanalysis, repair, or replacement. In addition, since the applicant included an enhancement to the "scope of program" program element to include fatigue crack growth analyses, which support the LBB analyses, ASME Code Section XI evaluations, and the HELB break selection criterion in the Fatigue Monitoring Program, the staff finds it appropriate that the applicant identified corrective actions associated with these additional types of analyses.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP X.M1 and finds it acceptable because when it is implemented the Fatigue Monitoring Program will include corrective actions to ensure that the cause of the condition is determined and preclude repetition, specifically fatigue reanalysis, repair, or replacement of the affected component, which is consistent with the GALL Report. In addition, the staff finds this enhancement acceptable because, consistent with SRP-LR Section A.1.2.3.7, the applicant identified appropriate correctives actions to take in order to maintain the components intended function(s) consistent with the CLB for the additional analyses included in the corresponding enhancement to the "scope of program" program element.

Enhancement 7. By letter dated April 26, 2013, the applicant revised LRA Section B3.1 to include an enhancement to the "parameters monitored or inspected" program element, which

states “[p]rocedures will be enhanced to limit the quantity of the most severe RCP component cooling water transient, elevated component cooling water (CCW) inlet temperature transients, to 75 percent of its design value, (i.e., limited to 150 transients), in order to accommodate the seasonal temperature change transient in the reactor coolant pump (RCP) thermal barrier flange fatigue analysis.”

The staff noted that the fatigue TLAA for the RCP thermal barrier flange was dispositioned in accordance with 10 CFR 54.21(c)(1)(iii), in that the effects of fatigue will be adequately managed by the Fatigue Monitoring Program for the period of extended operation. The staff’s review of the TLAA for the RCP thermal barrier flange is documented in SER Section 4.3.2.1.2. Specifically, the staff addresses the applicant’s ability to ensure that the accumulated fatigue usage for the RCP thermal barrier flange will not exceed the design limit without monitoring or confirmation that the number of occurrences of the seasonal temperature change transient will not exceed the design limit.

The staff noted that the revision to LRA Section B3.1 by letter dated April 26, 2013, was administrative in nature to ensure the procedures for the Fatigue Monitoring Program will be updated to clearly identify a specific limit for the elevated CCW inlet temperature transients to be 75 percent of its design value, (i.e., limited to 150 transients), in order to accommodate the seasonal temperature change transient in the RCP thermal barrier flange fatigue analysis. The staff’s evaluation of the applicant’s specified limit (of 75 percent of design value) for the elevated CCW inlet temperature transients is documented in SER Section 4.3.2.1.2.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP X.M1 and finds it acceptable because when it is implemented the applicant’s Fatigue Monitoring Program will monitor for elevated CCW inlet temperature transients, which cause cyclic strains and contribute to the fatigue usage factor, and the program will have a specified limit for this transient to ensure that the design limit is not exceeded during the period of extended operation for the RCP thermal barrier flange fatigue analysis; otherwise, corrective actions will be taken.

Enhancement 8. By letter dated April 26, 2013, the applicant revised LRA Section B3.1 to include an enhancement to the “corrective actions” program element, which states that procedures will be enhanced to include non-NUREG/CR-6260 locations with a U_{en} greater than 1.0 for further evaluation using the same methods as those used for NUREG/CR-6260 locations to remove conservatisms from the preliminary U_{en}.

The results of these final analyses will be incorporated into the Fatigue Monitoring program by either counting the transients assumed or incorporating the stress intensities into a CBF ability of the program. As an alternative, the Fatigue Monitoring Program will implement SBFs of certain locations in order to ensure the component does not exceed a U_{en} of 1.0. Any use of SBF will be implemented consistent with RIS 2008-30.

The staff’s evaluation of the methods used for the NUREG/CR-6260 locations to remove conservatisms from the preliminary U_{en} are documented in SER Section 4.3.4.2 and were determined to be acceptable and reasonable. The staff noted that these methods are not unique to just the NUREG/CR-6260 locations; thus, these methods to refine the U_{en} values are also applicable to non-NUREG/CR-6260 reactor coolant pressure boundary locations associated with this enhancement.

The staff noted that after refinement of U_{en} values are completed, which is consistent with the “corrective actions” program element of GALL Report AMP X.M1, these fatigue analyses will be

incorporated into the Fatigue Monitoring Program as part of this enhancement. The staff finds the inclusion of these fatigue analyses into the Fatigue Monitoring Program will ensure they remain valid through the period of extended operation by using cycle counting, CBF monitoring, or SBF monitoring; otherwise, corrective actions will be taken. The staff's evaluation of these monitoring methods is documented in SER Section 3.0.3.2.22.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP X.M1 and finds it acceptable because when it is implemented the applicant's Fatigue Monitoring Program will prevent the usage factor, including environmental effects of reactor water, from exceeding the design code limit during the period of extended operation by performing a more rigorous analysis of the component to demonstrate that the design code limit will not be exceeded. In addition, the staff finds that the monitoring methods implemented by the Fatigue Monitoring Program ensure that the design code limit is not exceeded during the period of extended operation; otherwise, corrective actions will be taken.

Enhancement 9. By letter dated April 26, 2013, the applicant revised LRA Section B3.1 to include an enhancement to the "corrective actions" program element: "[t]he sentinel location analysis, when refined, will be revisited to confirm bounding Reactor Coolant Pressure Boundary Environmentally Assisted Fatigue susceptible sentinel locations are updated appropriately and remain bounded consistent with the refined analysis."

During the staff's evaluation of the locations selected by the applicant for environmentally assisted fatigue monitoring as documented in SER Section 4.3.4.2, the staff noted that the refinement of a higher U_{en} may not ensure the reduction of the U_{en} for a bounded location, such that the conclusion from the common basis stress evaluation remains valid. Thus, the staff issued RAI 4.3-24 by letter dated March 26, 2013, requesting the applicant's justification. In its response dated April 26, 2013, the applicant provided this enhancement. The staff's review of the applicant's response to RAI 4.3-24 is documented in SER Section 4.3.4.2.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP X.M1 and finds it acceptable because when it is implemented the applicant's Fatigue Monitoring Program will confirm that, after the refinement of U_{en} values, the EAF locations monitored are appropriate to ensure environmentally assisted fatigue is managed through the period of extended operation.

Summary. Based on its audit of the applicant's Fatigue Monitoring Program and review of the applicant's responses to RAIs B3.1-1 and B3.1-2, 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 X.M1. 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 B3.1 summarizes operating experience related to the Fatigue Monitoring Program. The staff noted that the applicant's Fatigue Monitoring Program addressed generic operating experience as discussed below.

The applicant stated that Westinghouse performed a plant-specific evaluation of pressurizer surge line to address NRC Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification." This evaluation concluded that thermal stratification does not affect the integrity of the pressurizer surge line and, in the applicant's response to NRC Bulletin 88-11, describes the inspections,

analyses, and procedural revisions made to ensure that thermal stratification does not affect the integrity of the pressurizer surge line. The applicant also addressed NRC RIS 2008-30, "Fatigue Analysis of Nuclear Power Plant Components," which informed licensees of an analysis methodology used to demonstrate that compliance with the ASME Code fatigue acceptance criteria could be nonconservative if not correctly applied. The applicant addressed RIS 2008-30 by ensuring that a three-dimensional, six-component stress tensor method meeting ASME Code III NB-3200 requirements is used or by benchmarking its chosen method with ASME Code III NB-3200 requirements. This benchmarking has been performed for the normal and alternate charging nozzle to implement SBF at that location. The staff noted that the applicant's Fatigue Monitoring Program also addressed plant-specific operating experience. The applicant stated that an error was identified in the SBF transfer function for the normal and alternate charging nozzles, which incorrectly included thermal sleeves for the nozzles. The applicant confirmed that the extent of this condition is limited only to the normal and alternate charging nozzle SBF models, which subsequently have been updated to exclude thermal sleeves and benchmarked in accordance with NRC RIS 2008-30.

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 its audit, the staff reviewed the applicant's evaluation of plant-specific and generic operating experience related to its Fatigue Monitoring Program. The "operating experience" program element of GALL Report AMP X.M1 recommends that the program review industry experience relevant to fatigue cracking. The staff noted that RIS 2011-14, "Metal Fatigue Analysis Performed by Computer Software," was issued on December 29, 2011. This RIS is associated with the implementation of computer software packages used to demonstrate the ability of nuclear power plant components to withstand the cyclic loads associated with plant transient operations. Documentation of how the applicant addressed this recently issued RIS was not available to the staff during its audit; therefore, it is not clear if and how the applicant will address the issues discussed in RIS 2011-14.

The RIS states that the staff acknowledged that other computer software packages for performing ASME Code fatigue calculations may have or will be used by licensees; therefore, the staff encouraged licensees to review the documents discussed in the RIS and to consider actions, as appropriate, to ensure compliance with the requirements described in 10 CFR 50.55a and Appendix B to 10 CFR Part 50, respectively. Since the staff's concerns documented in the RIS were generic in nature to fatigue computer software, the staff noted during its audit that the applicant uses FatiguePro, which can perform cycle counting, CBF monitoring, and SBF monitoring to manage cumulative fatigue damage. Thus, it was not clear if the data collected by FatiguePro is reviewed and modified before the determination of cumulative fatigue usage for a component or of an accrued transient cycle.

By letter dated June 22, 2012, the staff issued RAI B3.1-3 requesting the applicant to describe and justify any actions that have been or will be taken to address the concerns described in RIS 2011-14, related to the use of computer software to demonstrate the ability of components to withstand cyclic loads associated with transients and the documentation of analyst's

engineering judgment and intervention. The applicant was also requested to describe the activities that are performed to the information and data collected by FatiguePro before determining the cumulative fatigue usage for a component or an accrued transient cycle and to justify if the concerns described in RIS 2011-14 have been addressed for the current use or will be addressed for the future use of computer software for fatigue calculations.

In its response dated July 20, 2012, the applicant stated that Callaway's CAP evaluated the RIS 2011-14 and concluded that it was specific to the WESTEMS™ Fatigue Monitoring Program software. The applicant stated that Callaway uses the FatiguePro Software to monitor fatigue usage and does not use WESTEMS™. The applicant clarified that Westinghouse has used WESTEMS™ to support fatigue analysis for Callaway. Therefore, subsequent to the issuance of RIS 2011-14, Westinghouse issued a letter dated January 16, 2012, in response to RIS 2011-14, which determined "Westinghouse is able to demonstrate that the calculations generated for the operating plants which use the WESTEMS™ program have not misused algebraic summation or the peak and valley options and have met all ASME Code limits." The applicant also stated that the following information was provided in Structural Integrity letter dated January 31, 2012, to document the impact of RIS 2011-14 on FatiguePro version 3:

> The software installed at ... Callaway ... (FatiguePro version 3) does not use the algebraic summation of three orthogonal moment vectors nor does it permit modification of stress peaks and valleys (the two issues in the RIS). Thus, FatiguePro version 3 installed at (Callaway) is not affected by NRC RIS 2011-14. Specifically,
>
> - FatiguePro version 3 does not perform NB-3600 analysis, so the concerns about how to calculate moment range in accordance with NB-3600 do not apply.
> - FatiguePro version 3 does not have a manual stress peak/valley editor.

Therefore, the applicant stated that based on the response provided by Westinghouse and Structural Integrity letters, there is no adverse condition that exists for Callaway associated with RIS 2011-14. The applicant further stated that the peak and valley times selected by the WESTEMS™ algorithm in the Callaway fatigue analysis were reviewed and confirmed to be applicable and conservative and that this review is documented in the Westinghouse calculations. The staff finds it appropriate that the applicant evaluated the specific concerns documented in RIS 2011-14 as part of its CAP to determine its applicability to its plant. In addition, the staff finds it appropriate that the applicant's vendors (i.e., Structural Integrity and Westinghouse) assessed the impact of RIS 2011-14 to its fatigue software on the applicant's site and determined that the applicant's site and fatigue calculations were not affected by the documented concerns.

The applicant further stated in its response that the only user manipulation that exists in the Fatigue Monitoring Program is to ensure that all transients were appropriately counted. The applicant described the three locations where the data was altered in some fashion in its FP-CALL-304, "Baseline Analysis of Callaway Plant Cycles and Fatigue Usage-Startup through 1/31/2011."

The first instance of user manipulation involved the revision to FatiguePro data files from May 11, 1995, through January 31, 2011, to expand the instrument list in these files to accommodate a software revision to FatiguePro. The applicant explained that this revision to the data files was necessary to properly work with the current FatiguePro version. The staff

finds this user manipulation appropriate because it ensured that compatibility issues between revisions of the computer software were corrected and it was confirmed that the fatigue analysis was not affected.

The second instance of user manipulation involved the correction to FatiguePro data files from May 11, 1995, through January 31, 2011, to remove instrument test data, drop-out points, and other obviously bad instrument data. The applicant stated that all data corrections are automatically logged by FatiguePro, which is retained with the supporting files of the baseline cycle and usage analysis. The applicant stated that this change was to ensure the accuracy of the data and to remove erroneous results that may trigger false positives. The staff finds this user manipulation acceptable because changes were made only to ensure accurate reflection of transient occurrences, and the Fatigue Monitoring Program currently includes a comparison of the actual severity and design severity of transients, as discussed in the applicant's response to RAI B3.1-1.

The third instance of user manipulation involved reclassification of the charging and letdown transients. The applicant explained that these transients are sometimes difficult to classify accurately using the automatic cycle counting logic and multiple events can be recorded when only one event has occurred. Therefore, the recorded charging and letdown transients were inspected to determine whether they had been counted accurately and in some cases the transients were reclassified based on the thermal effect of the charging and letdown flows on the charging nozzle. The applicant confirmed that these reclassifications are documented in the baseline cycle and usage analysis to ensure accountability. The staff finds this documentation in the analysis appropriate because it provides sufficient details such that a person technically qualified in the subject area can review and understand the reclassifications to verify the adequacy without recourse to the originator. The staff noted that the applicant's Fatigue Monitoring Program currently includes a comparison of the actual severity and design severity of transients, as discussed in response to RAI B3.1-1, to properly classify transients and ensure that design limits are not exceeded.

The staff finds the applicant's response to RAI B3.1-3 acceptable because the applicant evaluated recently issued industry operating experience and evaluated its impact on its plant. In addition, the staff finds the applicant's response acceptable because the applicant evaluated the specific concerns associated with the WESTEMS™ software identified in RIS 2011-14 and the generic concerns associated with documentation of user involvement when using fatigue computer software. The staff's concern described in RAI B3.1-3 is resolved.

Based on its audit and review of the application, and review of the applicant's response to RAI B3.1-3, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP X.M1 was evaluated.

FSAR Supplement. LRA Section A2.1 provides the FSAR supplement for the Fatigue Monitoring Program. The staff reviewed this FSAR 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 generally describes the key aspects of the program when implemented for the period of extended operation, which uses three monitoring methods (i.e., cycle counting, CBF fatigue monitoring, and SBF monitoring). However, the applicant's FSAR supplement in LRA Section A2.1 did not include a description or discussion of how the

monitoring methods will manage cumulative fatigue damage during the period of extended operation, which are key aspects to the applicant's Fatigue Monitoring Program.

By letter dated June 22, 2012, the staff issued RAI B3.1-4 requesting the applicant to revise LRA Section A2.1 to provide a description of how each monitoring method of the program will manage fatigue. Otherwise, the applicant was asked to justify why a revision to LRA Section A2.1 to capture these key aspects of the Fatigue Monitoring Program is not needed.

In its response dated July 20, 2012, the applicant stated that LRA Section A2.1 was revised by letter dated June 5, 2012, to provide a description of the cycle counting, CBF, and SBF monitoring methods of the Fatigue Monitoring Program. The staff reviewed the applicant's letter dated June 5, 2012, and confirmed that LRA Section A2.1 was amended to include a concise and accurate summary description of each monitoring method that manages metal fatigue to ensure the design limit of 1.0 is not exceeded during the period of extended operation. The staff's review of each monitoring method is discussed above.

The staff finds the applicant's response to RAI B3.1-4 acceptable because LRA Section A2.1 was amended to contain a summary description of the three monitoring methods (i.e., cycle counting, CBF, and SBF) that the Fatigue Monitoring Program uses for managing metal fatigue during the period of extended operation in accordance with 10 CFR 54.21(d). The staff's concern described in RAI B3.1-4 is resolved.

The staff also noted that the applicant committed (Commitment No. 31) to implement Enhancements 1 through 6 as captured in the FSAR supplement six months before the period of extended operation.

By letter dated October 17, 2013, the applicant amended LRA Section A2.1 to indicate that, in addition to considering the effects of the reactor water environment for a set that includes the NUREG/CR-6260 sample locations for a newer-vintage Westinghouse Plant and plant-specific bounding EAF locations in the reactor coolant pressure boundary, the applicant would include reactor vessel internals locations with fatigue usage calculations. The applicant indicated that the F_{en} factors will be determined as described in LRA Section A3.2.3 for reactor coolant pressure boundary components and reactor vessel internal locations. The staff noted LRA Section A3.2.3 identifies that NUREG/CR-6909 or NUREG/CR-6583 will be used for carbon and low alloy steels, NUREG/CR-6909 or NUREG/CR-5704 will be used for austenitic stainless steels, and NUREG/CR-6909 will be used for nickel alloys. The staff noted that, regardless of whether the components are reactor coolant pressure boundary or reactor vessel internals, they are both exposed to the same water environment. Thus, these components are impacted by environmentally assisted fatigue and the aforementioned NUREG reports are acceptable for use to address this aging effect. The staff finds the revision to LRA Section A2.1 acceptable because it clearly identifies the NUREG reports, which are consistent with those identified in the GALL Report, that will be used to address environmentally assisted fatigue for reactor coolant pressure boundary and reactor vessel internal components.

The staff finds that the information in the FSAR supplement, as amended by letters dated July 20, 2012, February 28, 2013, and October 17, 2013, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Fatigue 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 enhancements and confirmed that their implementation through Commitment No. 31 six months before 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 FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.23 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 enhancements, with GALL Report AMP X.S1, "Concrete Containment Tendon Prestress." The program manages the loss of tendon prestress aging effect in the post-tensioning system. The LRA states that the Concrete Containment Tendon Prestress Program is in accordance with Section XI Subsection IWL of the ASME B&PVC, 2001 Edition through the 2003 Addenda as required by 10 CFR 50.55a, except where the NRC has authorized an exemption or relief.

The LRA states that the containment is prestressed concrete, hemispherical dome-on-a-cylinder structures with a steel membrane liner and a flat foundation slab. The LRA states that ungrouted post-tensioned tendons inserted in ducts filled with anticorrosion petroleum grease permit the structures to withstand design basis accident internal pressures. The LRA also states that the vertical inverted U tendons are anchored through the bottom of the basemat.

The LRA states that the program's acceptance criterion is that measured tendon prestress must remain above or within a stated tolerance below the predicted lower limit (PLL) line for the vertical and hoop tendon groups and the PLL lines were developed from the loss of prestress model and are consistent with the proposed RG 1.35.1, "Determining Prestressing Forces for Inspection of Prestress Concrete Containments." The program also ensures that the average tendon prestress and trend lines for the tendon groups remain above the design basis minimum required value (MRV) until the next scheduled surveillance. The LRA also states that the trend lines are generated with a regression analysis, consistent with IN 99-10, Revision1, "Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments," Attachment 3. For both tendon groups, the regression analysis demonstrated that prestress should remain above the applicable MRVs for at least 60 years of operation; and that all tendons should, therefore, maintain their design basis function for the period of extended operation without retensioning. The LRA further states that the 5-year tendon surveillance required by the Callaway ASME Section XI Subsection IWL Program will continue to confirm that this is so for 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 X.S1.

The staff also reviewed the portions of the "scope of program," "parameters monitored or inspected," and "monitoring and trending" 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 B3.3 states an enhancement to the "scope of program" program element. In this enhancement, the applicant stated that "[t]he surveillance program specification will be enhanced to include random samples for the 40, 45, 50, and 55 year surveillances." The staff reviewed this enhancement against the corresponding program elements in GALL Report

AMP X.S1 and finds it acceptable because when it is implemented it will allow the periodic 5-year surveillance, random sampling, and assessment of the containment tendon prestressing force, through plant procedure C-1003(Q), "Specification for Inservice Inspection of the Containment Building Post-Tensioning System and Exterior Concrete Shell," to be continued into the period of extended operation. The surveillance, sampling, and assessment will contribute in the containment prestress force TLAA evaluation using 10 CFR 54.21(c)(1)(iii). Therefore, the inclusion of the enhancement will render the Concrete Containment Tendon Prestress Program "scope of program" program element consistent with the corresponding GALL Report AMP X.S1 program element.

Enhancement 2. LRA Section B3.3 states an enhancement to the "parameters monitored or inspected" program element. In this enhancement, the applicant stated that "[t]he surveillance program specification will be enhanced to extend the PLL lines for the vertical and hoop tendon groups to 60 years." The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP X.S1 and finds it acceptable because when it is implemented procedure C-1003(Q), "Specification for Inservice Inspection of the Containment Building Post-Tensioning System and Exterior Concrete Shell," will be used to calculate the PLL lines consistent with RG 1.35.1, "Determining Prestressing Forces for Inspection of Prestress Concrete Containments," for vertical and hoop tendon groups to 60 years. The staff finds that calculation of the PLL lines for 60 years is necessary to assess any abnormal degradation in actual tendon prestressing force, and the PLL constitutes the acceptance criteria for individual tendons. The difference between the PLL and the lift-off force is a measure of the degree of tendon relaxation or degradation. Lift-off forces less than the PLL, following 5-year lift-off test measurements in accordance with Section XI, Subsection IWL of the ASME B&PVC Code, as incorporated by reference in 10 CFR 50.55a, indicate potential abnormal relaxation or degradation in tendon prestressing force. Hence the inclusion of the enhancement will render the Concrete Containment Tendon Prestress Program, "parameters monitored or inspected" program element consistent with the corresponding GALL Report AMP X.S1 AMP program element.

Enhancement 3. LRA Section B3.3 states an enhancement to the "monitoring and trending" program element. In this enhancement, the applicant stated that "[t]he surveillance program specification will be enhanced to specifically require the final report for each surveillance interval to plot the measured results against time and to include the PLL, MRV, and trend lines. The surveillance program specification will be enhanced to require a regression analysis consistent with the requirements of NRC IN 99-10 Revision 1, Attachment 3." The staff reviewed this enhancement against the corresponding program element in GALL Report AMP X.S1 and finds it acceptable because when it is implemented the regression analysis lift-off trend lines calculated every 5 years through the period of extended operation will demonstrate whether the tendon prestressing force will remain above the MRV until the next scheduled surveillance. Hence, the inclusion of the enhancement will render the Concrete Containment Tendon Prestress Program, "monitoring and trending" program element consistent with the corresponding GALL Report AMP X.S1 program element.

Based on its audit and review 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 XI.S4. In addition, the staff reviewed the enhancements associated with the "scope of program," "parameters monitored or inspected," 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 B3.3 summarizes operating experience related to the Concrete Containment Tendon Prestress Program. The LRA states that the Callaway Concrete Containment Tendon Prestress Program to date did not identify any adverse trend in performance. The LRA states that the 25th year inspection report includes an examination and regression analysis incorporating the entire history of tendon prestress surveillance data, through the 2010 inspection, in accordance with NRC IN 99-10, Revision 1, "Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments," Attachment 3. The LRA also states that the regression analysis extends to 60 years and demonstrates that prestress in both the vertical and horizontal ("hoop") tendon groups remain above the applicable MRVs for at least 60 years of operation and that all tendons, therefore, maintain their design basis function for the period of extended operation without retensioning. Similarly, no individual-tendon data from the "common tendons" (one vertical and one horizontal, whose prestress is measured at each surveillance), or from the other sample tendons tested to date, show a loss of prestress sufficient to indicate a possible need to retension for at least 60 years. The LRA also states that results of tendon surveillance to date indicate that the post- tensioning system will continue to meet its design criteria through the period of extended operation.

The Callaway operating experience as audited demonstrates that it has been able to identify aging effects followed by corrective actions taken under the program. Occurrences identified under this program and corrective actions taken to prevent recurrence indicate that there is confidence that the continued implementation of the program will effectively identify aging before loss of intended function. For example, the staff noted during the audit that while in all prior surveillances the number of tendons examined followed guidance of RG 1.35 (a minimum of three tendons per group to be examined), the 20th-year surveillance for the hoop tendons failed to satisfy updated sampling requirements delineated in Table IWL-2521-1, Section XI, Subsection IWL of the ASME Code B&PVC and applicable addenda as required by 10 CFR 50.55a. The surveillance sampled only three hoop tendons instead of the required four. Since it was impractical to perform an additional examination within 24 hours of the surveillance, per TS 5.5.6, the provisions of SR 3.0.3 were invoked and a risk evaluation was performed. The probabilistic risk assessment evaluation report concluded that the large early release frequency (LERF), which is the limiting risk metric for this application, would not appreciably increase the accumulated risk. Therefore, it was deemed acceptable to defer the examination and test to the next scheduled surveillance. The staff also noted that the applicant scheduled to implement necessary changes in its own procedures, specifications, and FSAR. The staff reviewed the 25th-year surveillance and noted that it sampled the correct number of vertical and hoop tendons.

A further review by the staff of the 25th-year inspection report indicated that the applicant in its regression analysis initially did not include the 3rd-year tendon surveillance data. The staff noted that the applicant subsequently identified the missing data and, through its CAP, corrected the report. The predicted value for vertical tendons at 60 years without the 3rd-year data was 1,405 kips instead of the corrected 1,401 kips. The predicted value for the horizontal tendons at 60 years without the 3rd-year data was 1,322 kips instead of the corrected 1,317 kips. These constitute a variance of 0.3 percent and 0.4 percent, respectively, in the projected data. The staff also noted that the applicant reviewed the 90 percent confidence level lower bound for the predicted value (discussed in RG 1.35 and Section XI, Subsection IWL of the ASME Code B&PVC) and concluded that it remained unaffected. The staff further noted that 25th-year tendon surveillance properly initiated an engineering evaluation report through the plant's CAP when samples of an examined tendon wire did not pass the required elongation test at failure. The tendon, however, met all of the acceptance criteria, including satisfactory visual

examinations for anchorage, corrosion, defects, and grease replacement. No further action was taken as the maximum design stress of the tested tendon was higher than its ultimate strength.

Finally the staff noted that the applicant, through a self-assessment performed in 2010, identified nonsafety-related improvement in its containment post-tensioning system surveillance process and concluded that the plant is in alignment with peer plants on programmatic requirements and inspection involved processes.

The staff reviewed the operating experience information in the application and during the audit to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant. 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 that implementation of the program has resulted in the applicant taking corrective action. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP X.S1 was evaluated.

FSAR Supplement. LRA Section A2.3 provides the FSAR supplement for the Containment Tendon Prestress Program. The staff reviewed this FSAR 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. 32) to enhance the Concrete Containment Tendon Prestress Program specification six months before the period of extended operation to:

- include random samples for the 40-, 45-, 50-, and 55-year surveillances
- extend the PLL lines for the vertical and hoop tendon groups to 60 years
- specifically require the final report for each surveillance interval to plot the measured results against time and to include the PLL, MRV, and trend lines
- require a regression analysis consistent with the requirements of NRC IN 99-10 Revision 1, Attachment 3

These actions will be taken so that the program will adequately manage aging of applicable components during the period of extended operation.

The staff finds that the information in the FSAR supplement, as amended by letter dated February 28, 2013, 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 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. 32 six months before 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 FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

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

The applicant did not propose any AMPs not consistent with, or not addressed in, the GALL Report.

3.0.3.4 Aging Management Related to Loss of Coating Integrity for Internal Coatings on In-Scope Mechanical SSCs

Based on reviews conducted by the staff, the staff identified an issue concerning loss of coating integrity of internal coatings of piping, piping components, heat exchangers, and tanks. By letters dated October 7, 2013, and March 25, 2014, the staff issued RAI 3.0.3-2 and RAI 3.0.3-2a, respectively, to address this loss of coating integrity. In its responses dated December 20, 2013, April 23, 2014, May 6, 2014, and June 5, 2014, the applicant revised the Fire Water System, Fuel Oil Chemistry, Open-Cycle Cooling Water System, and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Programs to address loss of coating integrity of internal coatings of piping, piping components, heat exchangers, and tanks. The staff's evaluation of this issue and the applicant's responses are presented here.

3.0.3.4.1 Staff Evaluation

Managing Loss of Coating Integrity for Internal Coatings of Piping, Piping Components, Heat Exchangers, and Tanks. Based on recent staff reviews of several LRAs and of industry OE, the staff has determined that additional recommendations beyond those in the GALL Report should be considered in regards to managing loss of coating integrity for internal coatings of piping, piping components, heat exchangers, and tanks. This section of the SER presents measures acceptable to the staff for addressing loss of coating integrity for internal coatings and evaluates the applicant's responses to staff RAIs in this regard.

The staff has identified the following considerations:

- Periodic visual inspections of coatings to detect blistering, cracking, flaking, peeling, delamination, rusting, spalling (for cementitious coatings), and physical damage should be conducted. For purposes of license renewal, physical damage would be limited to age-related mechanisms such as that occurring downstream of a throttled valve as a result of cavitation versus damage caused by inspection activities (e.g., chipping of the coating due to installation of scaffolding, removal and reinstallation of inspection ports). Inspections are conducted for each coating material and environment combination. The coating environment includes both the environment inside the component (e.g., raw water) and the metal to which the coating is attached.

- Baseline inspections should be conducted in the 10-year period prior to the period of extended operation. Subsequent inspections should be based on the results of these and follow-on inspections as follows:

    (a) If no peeling, delamination, blisters, or rusting is observed during inspections, and cracking, flaking, or spalling (in cementitious coatings) has been found acceptable, subsequent inspections should be conducted 6 years after the most recent inspection. Peeling,

delamination, blisters, or rusting can be indicative of loss of adhesion that could result in the coating becoming debris or not being able to perform a corrosion deterrence function. Cracking, flaking, or spalling, although indicators to some degree of coating degradation, are not significant enough to require more frequent inspections as long as the condition has been found acceptable by qualified personnel. For example, despite cracking being found, the base metal could still be isolated from the environment and the coating retain sufficient integrity so as not to become debris.

(b) If the prior inspection results do not meet (a) above and a coatings specialist has determined that no remediation is required, subsequent inspections should be conducted 4 years after the most recent inspection. More frequent inspections are warranted to confirm the coatings specialist's evaluation. If two sequential subsequent inspections demonstrate no change in coating condition, subsequent inspections may be conducted at 6-year intervals.

(c) Given that coatings in redundant trains are exposed to the same environment, the inspection interval may be extended to 12 years as long as: (a) the identical coating material was installed with the same installation requirements in redundant trains (e.g., piping segments, tanks) with the same operating conditions and at least one of the trains is inspected every 6 years and (b) the coating is not in a location subject to turbulence that could result in mechanical damage to the coating.

(d) Given that the coatings installed on the internal surfaces of diesel fuel oil storage tanks are generally exposed to a static environment, the inspection interval may be conducted in accordance with GALL Report AMP XI.M30, "Fuel Oil Chemistry," as long as the inspection results meet (a) above.

- The extent of inspections should include all accessible tank and heat exchanger internal surfaces. The staff recognizes that, for piping, extensive amounts of coating could be installed. GALL Report AMPs such as XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," are based on sampling a portion of the population. The staff recommends the use of a sampling-based extent of inspections for coatings installed on the internal surfaces of piping. Where documentation exists that manufacturer recommendations and industry consensus documents (i.e., those recommended in RG 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Plants" or earlier versions of those standards) were used during installation, the extent of piping inspections may be twenty-five 1-foot axial length circumferential segments of piping or 20 percent of the total length of each coating material and environment combination. This extent of sampling is consistent with several GALL Report AMPs. However, where documentation does not exist that manufacturer recommendations and industry consensus documents were used during installation, the staff recommends that a larger extent of inspection be considered, for example, a sample consisting of seventy-three 1-foot axial length circumferential segments of piping or 50 percent of the total length of each coating material and environment combination. Regardless of the extent of inspections, the inspection surface should include the entire inside surface of the 1-foot sample. If geometric limitations impede movement of remote

or robotic inspection tools, the number of inspection segments should be increased in order to cover an equivalent length.

- The staff recommends that, where loss of coating integrity cannot result in downstream effects such as reduction in flow, drop in pressure, or reduction in heat transfer for in-scope components, a representative sample of external wall thickness measurements could be used to confirm the acceptability of the corrosion rate of the base metal in lieu of visual inspections of the coating. The wall thickness measurements are an appropriate method to manage loss of coating integrity in this case because base metal corrosion is the only effect of loss of coating integrity.

- RG 1.54 provides one method acceptable to the staff for training and qualification of individuals involved in coating inspections and evaluating degraded conditions.

- A preinspection review of the previous two inspections should be conducted, including reviewing the results of inspections and any subsequent repair activities. A coatings specialist should prepare the post-inspection report to include: a list and location of all areas evidencing deterioration, a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where repair can be postponed to the next refueling outage, and where possible, photographic documentation indexed to inspection locations. When corrosion of the base material is the only issue related to coating degradation of the component and external wall thickness measurements are used in lieu of internal visual inspections of the coating, the corrosion rate of the base metal should be trended. These recommendations are consistent with ASTM D7167-05, "Standard Guide for Establishing Procedures to Monitor the Performance of Safety-Related Coating Service Level III Lining Systems in an Operating Nuclear Power Plant," which is referenced in RG 1.54.

- Based on the staff's review of industry documents (e.g., ASTM, EPRI) the staff has concluded that, with the exception of Service Level I qualification testing, there are no acceptance criteria in recognized industry consensus documents for degraded coatings. Acceptance of degraded coatings is typically established by the coatings specialist. RG 1.54 states that for Service Level I coatings: (a) peeling and delamination shall not be permitted, (b) cracking is not considered a failure unless it is accompanied by delamination or loss of adhesion, and (c) blisters shall be limited to intact blisters that are completely surrounded by sound coating bonded to the surface. The staff recommends the following acceptance criteria for loss of coating integrity based on the guidance in RG 1.54.

  (a) Indications of peeling and delamination are not acceptable and the coating is repaired or replaced.

  (b) Blisters can be evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff guidance associated with use of a particular standard. Blisters should be limited to a few intact small blisters which are completely surrounded by sound coating bonded to the substrate. If the blister is not repaired, physical testing (e.g., lightly tapping the coating, adhesion testing) should be conducted to ensure that the blister is completely surrounded by sound coating bonded to the surface. Acceptance of a blister to remain in-service should be based both on the potential effects of flow blockage and degradation of the base material beneath the blister.

(c) If coatings are credited for corrosion prevention (e.g., corrosion allowance in design calculations is zero, the "preventive actions" program element credited the coating) and the base metal has been exposed or it is beneath a blister, the component's base material in the vicinity of the degraded coating should be examined to determine if the minimum wall thickness is met and will be met until the next inspection.

(d) Indications such as cracking, flaking, and rusting are to be evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff guidance associated with use of a particular standard.

(e) Minor cracking and spalling of cementitious coating is acceptable provided there is no evidence that the coating is debonding from the base material.

(f) As applicable, wall thickness measurements meet design minimum wall requirements.

(g) Adhesion testing results, when conducted, meet or exceed the degree of adhesion recommended in engineering documents specific to the coating and substrate.

- Coatings that do not meet acceptance criteria should be repaired or replaced. Testing or examination should be conducted to ensure that the extent of repaired or replaced coatings encompasses sound coating material. These recommendations are consistent with ASTM D7167-05, "Standard Guide for Establishing Procedures to Monitor the Performance of Safety-Related Coating Service Level III Lining Systems in an Operating Nuclear Power Plant," which is referenced in RG 1.54.

By letter dated October 7, 2013, the staff issued RAI 3.0.3-2 requesting that, if coatings have been installed on the internal surfaces of in-scope components (i.e., piping, piping subcomponents, heat exchangers, and tanks), the applicant state the inspection method, when inspections will commence and the frequency of subsequent inspections, the extent of inspections, the training and qualification of individuals involved in coating inspections, how trending of coating degradation will be conducted, acceptance criteria, and corrective actions for coatings that do not meet acceptance criteria.

The applicant responded to RAI 3.0.3-2 by letter dated December 20, 2013. The following sections address the aspects of that response and the staff's evaluation.

Visual Inspections. The applicant stated that visual inspections will be conducted to detect blistering, cracking, peeling, or delamination.

The staff finds this portion of the RAI response acceptable because visual inspections are an effective means to detect these types of potential coating degradation.

Baseline Inspections. The applicant stated that baseline inspections will be conducted during the 10-year period prior to the period of extended operation. Subsequent inspections will be as follows: (a) if no peeling, delamination, blisters, or rusting is observed, and any cracking or flaking has been found to be acceptable based on an evaluation by the coatings specialist, inspections will occur once every 6 years; (b) if no indications are found during the inspection of one train, the redundant train will not be inspected; (c) if the inspection results do not meet the conditions described in (a) and a coatings specialist determines that no remediation is required, inspections will occur every other refueling outage; and (d) repaired, replaced, or newly installed

coatings will be inspected in each of the following two refueling outages. In its response to RAI 3.0.3-2a Request (2), the applicant supported this approach for fuel oil storage tanks by stating that these tanks do not experience turbulent flow conditions.

The staff noted that, if no indications are found during inspection of one train, the redundant train would not need to be inspected as long as components within the redundant trains are not subject to turbulent conditions. By letter dated March 25, 2014, the staff issued RAI 3.0.3-2a Request (1) requesting that the applicant state the basis for why turbulent conditions sufficient to degrade internal coatings on the in-scope heat exchangers, air conditioners, and strainers described in the RAI response cannot occur.

In its response dated April 23, 2014, the applicant did not fully respond to RAI 3.0.3-2a Request (1); however, as amended by letter dated May 6, 2014, the applicant stated that the baseline inspection results will be used to determine if loss of coating integrity has occurred as a result of turbulent flow conditions. If there is evidence of turbulent conditions causing loss of coating integrity, the redundant train will be inspected, and the alternating train inspection frequencies will not be utilized. By letter dated June 5, 2014, the applicant amended the Open-Cycle Cooling Water System and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Programs (LRA Section B2.1.10 and B2.1.23) and Commitment No. 6 to state that the provision to conduct inspections every 6 years on an alternating train basis is based on no observed degradation or cracking and flaking that has been evaluated as acceptable, and the component is not subject to turbulent flow.

The staff finds the applicant's response acceptable because: (a) baseline inspections will be conducted prior to entering the period of extended operation in order to provide insight into the condition of coatings after many years of service; (b) subsequent inspection intervals will be based on the results of prior inspections such that where degraded coatings are noted, more frequent inspections will occur; (c) the maximum inspection intervals are consistent with staff recommendations for managing loss of coating integrity; (d) conducting alternating inspections of redundant trains when no indications are detected in prior inspections and turbulent flow conditions do not exist is consistent with staff recommendations for managing loss of coating integrity; (e) given that there will have been at least 30 years of service, the applicant will be able to determine whether turbulent flow conditions sufficient to cause coating degradation is occurring; and (f) it is reasonable to assume that turbulent flow conditions would not exist in the fuel oil storage tanks due to their large volume. The staff's concern regarding this portion of RAI 3.0.3-2 (inspection intervals) and RAI 3.0.3-2a Request (1) is resolved.

Coating Inspections. The applicant stated that coating inspection activities will be included in the following programs:

Aging Management Program	Components
Fire Water System	Fire water storage tanks
Fuel Oil Chemistry	Fuel oil storage tanks
Open-Cycle Cooling Water System	Component cooling water heat exchangers, electrical equipment air conditioners, control room air conditioners, essential service water self-cleaning strainers
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Service water pump strainers

The staff's evaluation of the aging management approach for each of the above components follows.

Fire Water Storage Tanks. The applicant stated that the interior surfaces of the fire water storage tanks will be inspected every other refueling outage interval. The staff noted that, as documented in SER Section 3.0.3.2.7, Enhancement No. 12, the applicant has revised the Fire Water System Program to include the augmented inspections in NFPA 25, "Inspection Testing and Maintenance of Water-Based Fire Protection Systems," Section 9.2.7 whenever pitting, corrosion, or coating failure is detected during internal visual inspections of the fire water storage tanks. The staff finds the Fire Water System Program acceptable to manage loss of coating integrity for the fire water storage tanks because the frequency of inspections are consistent with staff recommendations for managing loss of coating integrity and the augmented inspections of NFPA 25 Section 9.2.7 (e.g., adhesion testing, wet-sponge testing, dry film thickness readings) are sufficient to determine the condition of the coatings.

Fuel Oil Storage Tanks. LRA Section B2.1.16 states that, at least once every 10 years, each diesel fuel tank is drained and cleaned, and the internal surfaces are visually inspected. The staff has concluded that coating inspections for diesel fuel oil storage tanks may be conducted at the frequency stated in the Fuel Oil Chemistry Program (i.e., 10 years) as long as: (a) no peeling, delamination, blisters, or rusting are observed during inspections; and (b) any cracking and flaking has been found acceptable by a coatings specialist. If this is not the case, inspections should be conducted more frequently. The staff noted that the Fuel Oil Chemistry Program was not revised to include activities associated with coatings inspections (e.g., acceptance criteria, inspector qualifications). By letter dated March 25, 2014, the staff issued RAI 3.0.3-2a Request (2) requesting that the applicant: (a) state the periodicity of inspections, and basis for the periodicity of inspections if the prior inspection detected peeling, delamination, blisters, rusting, or unacceptable cracking and flaking; and (b) state how activities associated with coatings inspections (e.g., acceptance criteria, inspector qualifications) will be managed given that they are not included in the Fuel Oil Chemistry Program.

In its response dated April 23, 2014, the applicant revised LRA Section B2.1.16 to state: (a) visual inspections are performed on all accessible internal surface coatings of the diesel fuel oil storage tanks and day tanks; (b) baseline inspections will be conducted in the 10-year period prior to the period of extended operation; (c) coatings are inspected every 6 years on an alternating train basis; (d) coatings with blisters, peeling, delaminations, or rusting that have been determined not to require remediation are inspected on a 4-year frequency; (e) when peeling, delaminations and blisters are determined to not meet the acceptance criteria and that

the degraded coating will not be repaired or replaced, physical testing (i.e., destructive or nondestructive adhesion testing using ASTM International Standards endorsed in RG 1.54, is performed where physically possible (i.e., sufficient room to conduct testing); (f) monitoring and trending of coatings is based on a review of the previous two inspections results (including repairs) with the current inspection results; and (g) the training and qualification of individuals involved in coating inspections are conducted in accordance with ASTM International Standards endorsed in RG 1.54 including guidance from the staff associated with a particular standard. Acceptance criteria includes: (a) indications of peeling and delamination are not acceptable, and the coatings are repaired or replaced; (b) blisters are evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54, including staff guidance associated with use of a particular standard; (c) indications such as cracking, flaking, and rusting are to be evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54, including staff guidance associated with use of a particular standard; and (d) adhesion testing results meet or exceed the degree of adhesion recommended in engineering documents specific to the coating and substrate. Inspection results not meeting the acceptance criteria will be evaluated by a qualified coatings evaluator and corrective actions will be determined using the Corrective Action Program.

The staff finds the applicant's response and proposal to use the Fuel Oil Chemistry Program to manage loss of coating integrity for the fuel oil storage tanks acceptable because the inspection frequencies and activities associated with coatings inspections are consistent with staff recommendations for managing loss of coating integrity. The staff's concern described in RAI 3.0.3-2a Request (2) is resolved.

Heat Exchangers, Air Conditioners, and Strainers. The applicant stated that 100 percent of the accessible interior surfaces of these components will be inspected. LRA Sections A1.10, A1.23, B2.1.10, and B2.1.23 were revised to include managing loss of coating integrity. However, the staff noted that the FSAR supplements and programs did not include all of the key aspects of the program associated with coating degradation. By letter dated March 25, 2014, the staff issued RAI 3.0.3-2a Request (5) and Request (6) requesting that the applicant state why LRA Sections A1.10 and A1.23 do not include a summary description of the followup testing that will be conducted when degradation is determined not to meet acceptance criteria, and state the basis for the training and qualification of individuals involved in coating inspections. The staff also requested that the applicant justify why LRA Sections B2.1.10 and B2.1.23 do not include: (a) when baseline inspections will be conducted; (b) the inspection interval for subsequent inspections; (c) the extent of inspections; (d) qualifications for individuals performing activities associated with coating inspections; (e) a summary description of how monitoring and trending of the coatings will be conducted; (f) acceptance criteria; and (g) a summary description of corrective actions when coating degradation is detected.

In its response dated April 23, 2014, the applicant revised LRA Sections B2.1.10 and B2.1.23 to include the same level of detail as described above for the Fuel Oil Chemistry Program. In addition, LRA Section B2.1.23 was revised to state that, for the service water piping from the circulating and service water pump house to the ESW system connection, seventy-three 1-foot axial length circumferential segments of piping will be inspected in each inspection interval. The applicant also revised LRA Sections A1.10 and A1.23 to include a summary description of the followup testing that will be conducted when degradation is determined not to meet acceptance criteria and the basis for the training and qualification of individuals involved in coating inspections

The staff finds the applicant's response and proposal to use the Open-Cycle Cooling Water System and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Programs to manage loss of coating integrity for the component cooling water heat exchangers, electrical equipment air conditioners, control room air conditioners, essential service water self-cleaning strainers, and service water pump strainers acceptable because the activities associated with coatings inspections are consistent with staff recommendations for managing loss of coating integrity. The staff's concerns described in RAI 3.0.3-2a Request (5) and Request (6) are resolved.

Training and Qualification of Personnel. Regarding the training and qualification of personnel performing the inspections, the applicant stated that coating inspections will be performed by individuals qualified to ANSI N45.2.6, "Qualification of Inspections, Examinations, and Testing Personnel for Nuclear Power Plants." Inspection reports will be provided to the site coatings coordinator for evaluation. The site coatings coordinator will be qualified consistent with ASTM D7108-5, "Standard Guide for Establishing Qualifications for a Nuclear Coating Specialist."

The staff noted that qualifications meeting the recommendations in Regulatory Guide (RG) 1.54, "Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants," are consistent with staff recommendations for managing loss of coating integrity. The staff finds this portion of the response to RAI 3.0.3-2 (training and qualification) acceptable because the use of D7108-5 is endorsed by RG 1.54 and ANSI N45.2.6 certification is an acceptable basis for qualifying coatings inspectors based on RG 1.54, June 1973, Section C.1, which endorses conformance to the ANSI N45.2 quality assurance standards.

Monitoring and Trending of Results. The applicant also stated that monitoring and trending will include the review of previous inspection results prior to performing the inspections and inspection results will be compared to previous inspection results.

The staff noted that the program does not state who will prepare the post-inspection report nor the details that will be included in the report. By letter dated March 25, 2014, the staff issued RAI 3.0.3-2a Request (7), requesting that the applicant state who will prepare and approve post-inspection reports and the key information that will be included in the report.

In its response dated April 23, 2014, the applicant stated that a coatings specialist prepares and approves the post-inspection report. The response also states that the report includes a list and location of all areas evidencing deterioration, a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where repair can be postponed to the next refueling outage, and where possible, photographic documentation indexed to inspection locations.

The staff finds the applicant's response and proposal to trend coating degradation acceptable because they are consistent with staff recommendations for managing loss of coating integrity. The staff's concern described in RAI 3.0.3-2a Request (7) is resolved.

Acceptance Criteria. The applicant stated that acceptance criteria would be as follows: (a) peeling and delaminations are not permitted; (b) cracking is not permitted if accompanied by delamination or loss of adhesion; (c) blisters are limited to intact blisters with testing being performed to confirm that the blister is surrounded by coating that is bonded to the base material; and (d) localized areas of coating degradation without subsequent loss of material of the base metal are considered acceptable if the area is completely surrounded by sound coating bonded to the surface.

The staff lacked sufficient information to conclude that the proposed followup testing would be sufficient to provide reasonable assurance that a component would be able to perform its current licensing basis intended function(s). By letter dated March 25, 2014, the staff issued RAI 3.0.3-2a Request (3), requesting that the applicant state what testing will be performed when peeling, delamination or blisters are detected during inspections and the coating is not repaired or replaced, and how it will be determined that a repair or replacement of a coating is extended to sound coating material.

In its response dated April 23, 2014, the applicant stated the following:

> For peeling, delaminations and blisters determined to not meet acceptance criteria and that will not be repaired or replaced, physical testing is performed where physically possible (i.e., sufficient room to conduct testing). Testing consists of destructive or nondestructive adhesion testing using ASTM International Standards endorsed in RG 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Plants." For repaired or replaced coating, a minimum of three sample points adjacent to the defective area are tested to verify sound coating material.

The staff noted that the applicant did not revise its programs to state that three sample points would be tested to verify sound coating material. However, the staff noted that testing three points is the industry standard (e.g., ASTM D4541, "Standard Test Method for Pull-Off Strength of Coatings Using Portable Adhesion Testers," ASTM D7234 "Standard Test Method for Pull-Off Adhesion Strength of Coatings on Concrete Using Portable Pull-Off Adhesion Testers"). The staff finds the applicant's response acceptable because it is consistent with staff recommendations for managing loss of coating integrity. The staff's concern described in RAI 3.0.3-2a Request (3) is resolved.

Crediting Coatings for Corrosion Prevention. The staff recommends that if coatings are credited for corrosion prevention and the component's base material has been exposed or is beneath a blister, the base metal should be examined to determine if minimum wall thickness is met and will be met until the next inspection. By letter dated March 25, 2014, the staff issued RAI 3.0.3-2a Request (4) requesting that the applicant state: (a) whether a component's base material will be inspected if its coatings have been credited for corrosion prevention and the base metal has been exposed or is beneath a blister, and (b) the inspection method and acceptance criteria. The staff also requested that, if inspections will not be conducted, the applicant state the basis for why there is reasonable assurance that the current licensing basis intended function of the component will be met.

In its response dated April 23, 2014, the applicant stated, "[n]one of the internally coated components within the scope of license renewal have credited the coatings for corrosion prevention either in a documented corrosion allowance in a design analysis or as a preventative action in an aging management program." The applicant also stated that, if the base metal is exposed due to coating degradation, the applicable inspection requirements for management of loss of material in the component will apply and blisters will be evaluated by a qualified coatings specialist to determine extent of coating degradation and exposure of the base metal.

The staff noted that: (a) the coatings have not been credited for corrosion prevention in the in-scope component's design analyses; (b) if the base metal is exposed, followup inspections will occur; and (c) qualified personnel will evaluate the condition of the blisters. The staff finds the applicant's response acceptable because the potential for through-wall corrosion is minimal because the coatings were not credited in the design of the component and the followup

examinations of the base metal and blister are capable of detecting the extent of base metal degradation. The staff's concern described in RAI 3.0.3-2a Request (4) is resolved.

The staff noted that the applicant addressed rusting in its response to RAI 3.0.3-2a Request (1) which stated that, "[c]oatings with blisters, peeling, delaminations or rusting that has been determined not to require remediation are inspected on a four year frequency," and Request (2), included the term in each of the applicable programs. The staff finds this portion of the response to RAI 3.0.3-2 (acceptance criteria) acceptable because it is consistent with staff recommendations for managing loss of coating integrity.

Corrective Actions. In regard to corrective actions, the applicant stated that inspection results that do not meet acceptance criteria will be evaluated by the site coatings coordinator. The applicant also stated that corrective actions may include repair, replacement, or continued monitoring.

The staff finds this portion of the response to RAI 3.0.3-2 (corrective actions) acceptable because it is consistent with staff recommendations for managing loss of coating integrity.

During its review of the response to RAI 3.0.3-2, the staff noted that the applicant cited loss of material as the applicable aging effect for new AMR items associated with internal coatings in LRA Tables 3.3.2-4, 3.3.2-5, 3.3.2-7, 3.3.2-11, 3.3.2-20, and 3.3.2-21. By letter dated March 25, 2014, the staff issued RAI 3.0.3-2a Request (8) requesting that the applicant state why the term "loss of material" as an aging effect for coatings is sufficient to convey the consequential concepts of unanticipated or accelerated corrosion and debris generation, or revise the aging effect to loss of coating integrity in the cited AMR tables.

In its response dated April 23, 2014, the applicant revised 3.3.2-4, 3.3.2-5, 3.3.2-7, 3.3.2-11, 3.3.2-20, and 3.3.2-21 to identify loss of coating integrity as the applicable aging effect. The applicant also stated that loss of coating integrity is only applicable to the service water supply piping that connects to the essential service water system supply piping. Loss of coating integrity is not applicable to the service water and circulating water system return piping downstream of in-scope essential service water components because degraded coatings cannot result in downstream effects (e.g., reduction in flow, drop in pressure, reduction in heat transfer) for in-scope components. Also, the internal coating for the service water and circulating water return line is not credited for corrosion prevention.

The staff finds the applicant's response acceptable because the appropriate aging effect has been identified in the AMR tables, and for the service water and circulating water system return piping downstream of in-scope essential service water components, the staff agrees that loss of coating integrity is not an applicable aging effect because degraded coatings in these portions of the systems would not result in downstream effects and, in regard to loss of base material, the coatings were not credited for corrosion prevention. The staff's concern described in RAI 3.0.3-2a Request (8) is resolved.

Summary. In summary, the staff finds the applicant's responses to RAI 3.0.3-2 and RAI 3.0.3-2a acceptable as documented in the staff's evaluation of each portion of the RAI responses above.

3.0.3.4.2 Conclusion

On the basis of its technical review of the applicant's changes to the Open-Cycle Cooling Water System, Fire Water System, Fuel Oil Chemistry, and Inspection of Internal Surfaces in

Miscellaneous Piping and Ducting Components Programs to address loss of coating integrity, 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 FSAR supplement for these AMPs and concludes that they provide an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.4 Quality Assurance Program Attributes Integral to Aging Management Programs

3.0.4.1 Summary of Technical Information in the Application

In LRA Appendix A, Section A1, "Summary Description of Aging Management Programs," and Appendix B, Section B.1.3, "Quality Assurance Program and Administrative Controls," the applicant described the elements of corrective action, confirmation process, and administrative controls that are applied to the AMPs for both safety-related and nonsafety-related components.

LRA Appendix A, Section A1 states:

> Three elements common to all aging management programs discussed in Sections A1 and A2 are corrective actions, confirmation process, and administrative controls. These elements are included in the Callaway Plant QA Program, which implements the requirements of 10 CFR Part 50, Appendix B. The Callaway Plant QA Program is applicable to safety-related systems, structures and components that are subject to aging management review activities for license renewal. These three elements will also be applied to the nonsafety-related systems, structures, and components subject to aging management activities after enhancement to existing Callaway procedures.

LRA Appendix B, Section B.1.3 states:

> The corrective action, confirmation process, and administrative controls, of the Callaway (10 CFR Part 50, Appendix B) Quality Assurance Program are applicable to all systems, structures, and components (SSCs) subject to aging management programs and activities required during the period of extended operation.
>
> Procedures will be enhanced apply the elements of corrective actions, confirmation process, and administrative controls of the Callaway Plant Quality Assurance program to those nonsafety-related SSCs requiring aging management.

3.0.4.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), an applicant is required to demonstrate that the effects of aging on SCs subject to an AMR will be adequately managed so that their intended functions will be maintained consistent with the CLB for the period of extended operation. The SRP-LR, Branch Technical Position RLSB-1, "Aging Management Review - Generic," describes 10 attributes of an acceptable AMP. Three of these 10 attributes are associated with the QA activities of corrective action, confirmation process, and administrative controls. Table A.1-1, "Elements of an Aging Management Program for License Renewal," of 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 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 gives 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 A, Section A1, and Appendix B, Section B.1.3, of the LRA, which describe how the existing Callaway QA Program includes the QA-related elements (corrective action, confirmation process, and administrative controls) for AMPs consistent with the staff's guidance described in Branch Technical Position IQMB-1. The staff also reviewed a sample of AMP program basis documents and confirmed that the AMPs implement the CAP, confirmation processes, and administrative controls as described in the LRA. Based on its review, the staff determined that the quality attributes presented in the AMP program basis documents and the associated AMPs are consistent with the staff's position on QA for aging management.

3.0.4.3 Conclusion

On the basis of the staff's evaluation of Appendix A, Section A1 and Appendix B, Section B.1.3 of the LRA, and the AMP program basis documents, the staff concludes that the QA attributes (corrective action, confirmation process, and administrative control) of the applicant's AMPs are consistent with SRP-LR, Branch Technical Position RLSB-1.

3.0.5 Operating Experience for Aging Management Programs

3.0.5.1 Summary of Technical Information in Application

LRA Section B1.4, "Operating Experience," describes how the applicant considered operating experience in the preparation of the application. The LRA states that the applicant reviewed both plant-specific and industry operating experience. The applicant obtained plant-specific operating experience from CAP records generated from January 1999 to June 2011. Industry operating experience was obtained from NRC generic letters, generic safety issues, information circulars, inspection and enforcement bulletins, INs, and RISs. The LRA also states that the

operating experience review also included input from plant staff. The AMP descriptions in LRA Appendix B summarize the results of the applicant's operating experience review.

LRA Section B1.4 also describes how future plant-specific and industry operating experience will be reviewed by the applicant. The LRA states that Ameren Missouri will review industry operating experience from such sources as NRC generic communications, reports made in accordance with 10 CFR Part 21, "Reporting of Defects and Noncompliance," licensee event reports, and nonconformance reports. The applicant's review of plant-specific operating experience will include sources such as event investigations, trending reports, lessons learned, self-assessments, and the 10 CFR Part 50, Appendix B, corrective action process. The LRA further states that, upon receipt of the renewed operating license, Ameren Missouri will use these reviews to confirm the effectiveness of the AMPs, determine the need for AMP enhancements, and indicate the need to develop new AMPs.

3.0.5.2 Staff Evaluation

3.0.5.2.1 Overview

In accordance with 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 Appendix A describes 10 program elements of an acceptable AMP, and program element 10, "operating experience," is described in SRP-LR Section A.1.2.3.10. On March 16, 2012, the staff issued Final LR-ISG-2011-05, "Ongoing Review of Operating Experience." This LR-ISG includes interim revisions to the SRP-LR that clarify the staff's acceptance criteria and review procedures with respect to operating experience review activities conducted under a renewed license. Specifically, LR-ISG-2011-05 revises the operating experience criteria in SRP-LR Section A.1.2.3.10 to state the following:

(1) Consideration of future plant-specific and industry operating experience relating to AMPs should be discussed. The ongoing review of operating experience may identify areas where AMPs should be enhanced or new AMPs developed. As such, an applicant should ensure that it has adequate processes to monitor and evaluate plant-specific and industry operating experience related to aging management to ensure that the AMPs are effective in managing the aging effects for which they are credited. The AMPs are informed by this review of operating experience on an ongoing basis, regardless of the AMP's implementation schedule. The ongoing review of operating experience information should provide objective evidence to support the conclusion that the effects of aging are managed adequately so that the [SC] intended function(s) will be maintained during the period of extended operation.

(2) Currently available operating experience with existing programs should be discussed. The operating experience of 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 not been fully effective in intercepting aging degradation in a timely manner. This information should provide objective evidence to support the conclusion that

the effects of aging will be managed adequately so that the [SC] intended function(s) will be maintained during the period of extended operation.

(3) Currently available operating experience applicable to new programs also should be discussed. 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 or generic industry operating experience that is relevant to the program elements, even though the operating experience was not identified through implementation of the new program. Thus, when developing the elements for new programs, an applicant should consider the impact of relevant operating experience from implementation of its existing AMPs and from generic industry operating experience.

SER Section 3.0.3 discusses the staff's review of the second and third criteria, which concern currently available operating experience associated with existing and new programs, respectively. The following evaluation covers the staff's review of the first criterion, which concerns the consideration of future operating experience and applies to both existing and new AMPs.

3.0.5.2.2 Consideration of Future Operating Experience

LR-ISG-2011-05 Appendix A establishes a new SRP-LR Section A.4. This section provides a framework for ongoing activities acceptable to address operating experience concerning age-related degradation and aging management during the term of a renewed operating license to ensure that the effects of aging are managed adequately. The staff evaluated the applicant's operating experience review activities, as described in LRA Section B1.4, against the staff position in SRP-LR Section A.4.2.

Based on its evaluation, the staff determined that the applicant intends to use the existing CAP and Operating Experience Program to evaluate operating experience and ensure the effectiveness of the aging management activities. However, the staff determined that the LRA does not provide sufficient details to describe how these existing processes will be used on an ongoing basis to capture and evaluate operating experience relative to the applicant's bases for managing age-related degradation. By letter dated August 6, 2012, the staff issued RAI B1.4-1 requesting the applicant to describe in detail the programmatic activities that it will use to continually identify aging issues, evaluate them, and, as necessary, enhance the program elements of applicable AMPs or develop new AMPs. The staff also requested the applicant to state if the activities are consistent with the guidance in LR-ISG-2011-05. Otherwise, the staff requested the applicant to provide a basis for concluding that its programmatic activities will ensure that operating experience will be reviewed on an ongoing basis during the term of the renewed license for its impact on the aging management bases.

In its response dated September 6, 2012, the applicant provided additional information to describe how it will address plant-specific and industry operating experience under its CAP and Operating Experience Program. The applicant also described how the activities conducted under these programs align with the guidance in LR-ISG-2011-05. To be consistent with this guidance, the applicant identified several enhancements to its existing operating experience review practices.

The staff reviewed the applicant's response to RAI B1.4-1 and determined that the response does not clearly establish if the applicant's ongoing programmatic activities for reviewing

operating experience are considered to be consistent with the further review areas in SRP-LR Section A.4.2, as established in LR-ISG-2011-05. Therefore, by letter dated December 7, 2012, the staff issued RAI B1.4-1a requesting the applicant to clarify if the operating experience activities are consistent with SRP-LR Section A.4.2. The staff specifically requested the applicant to provide clarification on the following aspects of its operating experience review activities: (a) how operating experience from industry guidance documents and standards would be captured, (b) identification and evaluation of adverse age-related trends, (c) consideration of activities, criteria, and evaluations integral to the elements of the AMPs in the operating experience evaluations, (d) documentation of AMR-related information in the operating experience evaluations, (e) review of satisfactory and unsatisfactory AMP results for appropriate adjustments to the aging management inspection activities, (f) training requirements for certain personnel that have key responsibilities for processing operating experience, and (g) time when the aging management coordinator, who will be primarily responsible for implementing the aging management activities, will begin processing age-related operating experience. The staff requested the applicant to identify and justify any areas of inconsistency with the guidance in SRP-LR Section A.4.2.

In its response dated December 19, 2012, the applicant provided additional information to address aspects of the operating experience review activities raised by the staff in RAI B1.4-1a. The applicant provided this information as a supplement to its response to RAI B1.4-1. In summary, the response indicates that the operating experience review activities are consistent with the guidance in SRP-LR Section A.4.2.

The staff evaluated the applicant's description of the ongoing operating experience review activities as provided in response to RAIs B1.4-1 and B1.4-1a. The staff evaluated the consistency of these activities with the guidance in SRP-LR Section A.4.2 on "Acceptable Use of Existing Programs" and "Areas of Further Review." The staff's evaluations with respect to these two sections of guidance follow in SER Sections 3.0.5.2.3 and 3.0.5.2.4, respectively.

3.0.5.2.3 Acceptability of Existing Programs

SRP-LR Section A.4.2 describes existing programs generally acceptable to the staff for the capture, processing, and evaluation of operating experience concerning age-related degradation and aging management during the term of a renewed operating license. The acceptable programs are those relied upon to meet the requirements of 10 CFR Part 50, Appendix B, and 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. SRP-LR Section A.4.2 also states that, as part of meeting the requirements of NUREG-0737, Item I.C.5, the applicant's operating experience program should rely on active participation in the Institute of Nuclear Power Operations (INPO) operating experience program (formerly the INPO Significant Event Evaluation and Information Network (SEE-IN) program endorsed in NRC GL 82-04, "Use of INPO SEE-IN Program").

In its supplemental response to RAI B1.4-1 dated December 19, 2012, the applicant stated that it will use its existing CAP and Operating Experience Program to ensure that the AMPs will continue to be effective in managing the effects of aging. The applicant also stated that it will use these programs to enhance the AMPs or develop new AMPs when the review of operating experience indicates that the AMPs may not be fully effective. The applicant stated that its Operating Experience Program is an established program that has evolved over time and has its roots in the INPO SEE-IN program. The applicant further stated that the CAP is used with the Operating Experience Program to evaluate and address degraded conditions, including

plant-specific and industry operating experience. LRA Section B1.3 states that the applicant implements its CAP in accordance with the requirements of 10 CFR Part 50, Appendix B. Based on this information, the staff determined that the applicant's use of the existing CAP and Operating Experience Program is consistent with the programs described in SRP-LR Section A.4.2 and, therefore, generally acceptable for the capture, processing, and evaluation of age-related operating experience.

3.0.5.2.4 Areas of Further Review

Notwithstanding the general acceptability of existing programs, certain areas of the applicant's operating experience review activities are subject to further staff review as described in SRP-LR Section A.4.2. The staff's reviews of these areas follow.

Application of Existing Programs and Procedures to the Processing of Operating Experience Related to Aging. SRP-LR Section A.4.2 states that the programs and procedures relied upon to meet the requirements of 10 CFR Part 50, Appendix B, and NUREG-0737, Item I.C.5, should not preclude the consideration of operating experience on age-related degradation and aging management. In response to RAI B1.4-1, as supplemented by letter dated December 19, 2012, the applicant stated that it currently uses its existing CAP and Operating Experience Program to consider and address operating experience related to aging. However, to ensure that the consideration of age-related operating experience is not precluded, the applicant stated that it will enhance these programs to provide specific direction to identify, evaluate, and communicate operating experience related to aging. In an amendment to the LRA submitted by letter dated December 19, 2012, the applicant stated that it had completed this enhancement. The staff reviewed the applicant's response and determined that the CAP and Operating Experience Program will not preclude the capture and evaluation of operating experience related to aging because the applicant has enhanced these programs to clarify that they will specifically be used for these purposes. The applicant's use of these programs for processing operating experience is, therefore, consistent with the guidance in SRP-LR Section A.4.2.

SRP-LR Section A.4.2 also states that the applicant should use the option described in SRP-LR Appendix A.2 to expand the scope of the 10 CFR Part 50, Appendix B, program to include nonsafety-related structures and components. As discussed in SER Section 3.0.4, the staff determined that the applicant's inclusion of nonsafety-related structures and components within the scope of its 10 CFR Part 50, Appendix B, program is consistent with the guidance in SRP-LR Appendix A.2 and, therefore, also consistent with the guidance in SRP-LR Section A.4.2.

Consideration of Industry Guidance Documents as Operating Experience. SRP-LR Section A.4.2 states that NRC and industry guidance documents and standards applicable to aging management, including revisions to the GALL Report, should be considered as sources of industry operating experience and evaluated accordingly.

In its December 19, 2012, response to RAI B1.4-1a the applicant stated that its processes include review of industry operating experience sources based on the categories in INPO's "Guidelines for Use of Operating Experience" document. These sources primarily include INPO event reports, NRC generic communications (i.e., bulletins, GLs, INs, and RISs), topical reports, and vendor correspondence, including reports made in accordance with 10 CFR Part 21, "Reporting of Defects and Noncompliance." As an enhancement, the applicant stated that it will add LR-ISG documents as an additional source of industry operating experience to be reviewed under the Operating Experience Program. In an amendment to the LRA submitted by letter dated December 19, 2012, the applicant stated that it had completed this enhancement. In its

response to RAI B1.4-1a the applicant further stated that, because industry operating experience can be derived from many sources, the CAP requires documentation and further evaluation when it identifies other sources of industry operating experience applicable to Callaway. The staff reviewed the applicant's response and finds the sources of industry operating experience prescribed for review under the Operating Experience Program acceptable. These sources are acceptable because the staff considers them to be the primary sources of industry operating experience and because they are consistent with those sources outlined in the INPO guidelines, which the staff has endorsed by Generic Letter 82-04. The staff also finds the addition of LR-ISG documents acceptable because these NRC-generated documents can contain insights applicable to aging management.

To illustrate when other sources of industry operating experience applicable to Callaway will be documented in the CAP for further evaluation, the applicant stated in its response to RAI B1.4-1a that it would consider a guidance document or standard referenced in one of the sources covered by the INPO document categories. However, from this one example, the staff determined that it is not clear if the applicant only identifies industry operating experience applicable to Callaway from INPO-communicated sources, or if the applicant also will rely on other activities to identify sources of industry operating experience for evaluation. By letter dated January 30, 2013, the staff issued RAI B1.4-1b requesting the applicant to describe the activities used to identify other industry- and NRC-generated guidance documents and standards applicable to Callaway and to justify the adequacy of these activities for identifying guidance documents and standards on age-related degradation and aging management.

In its response dated February 14, 2013, the applicant stated that its procedures allow for the consideration of additional sources of industry operating experience (i.e., sources outside of the ones prescribed for review under the Operating Experience Program), and plant personnel may enter such sources into the CAP for review. The applicant stated that it will use its self-assessment and benchmarking processes as a primary means to identify these additional sources. These processes include activities such as participation in industry working groups and benchmarking of AMPs at other nuclear power plants. The applicant also stated that, through these activities, it will maintain awareness of new industry operating experience concerning age-related degradation and aging management. The applicant's response further stated that certain plant personnel will receive training on age-related degradation and aging management topics, and the applicant expects these personnel to identify (e.g., through participation in a self-assessment or benchmarking activity) lessons learned and available guidance documents and standards and determine if this new information warrants review for Callaway. The staff reviewed the applicant's response and finds it acceptable because, although the applicant's Operating Experience Program prescribes review of a primary set of industry operating experience sources, the applicant does not limit its reviews to only these sources. The staff finds that the activities described by the applicant, namely self-assessments, benchmarking its AMPs against AMPs at other nuclear power plants, and participation in industry working groups, in combination with the training on age-related topics for personnel involved with these activities, are suitable to identify these other sources of industry operating experience. The staff's concern described in RAI B1.4-1b regarding the identification of other sources of industry operating experience is resolved.

On considering revisions of the GALL Report as a source of operating experience, in its response to RAI B1.4-1a the applicant stated that it will not explicitly review periodic updates to the GALL Report unless the NRC communicates these updates to licensees by an accompanying generic communication. The staff reviewed the sources of industry operating experience considered by the applicant and determined that one source is topical reports. Per

its abstract, the GALL Report should be treated as an approved topical report; therefore, the staff determined that it is not clear why the applicant's operating experience review processes capture some topical reports, but possibly omit others that are specifically related to aging management, such as GALL Report revisions. Therefore, in RAI B1.4-1b the staff also requested the applicant to justify why an update to the GALL Report would not be captured and reviewed as a topical report under the Operating Experience Program. The staff also requested the applicant to state if the program will exclude the capture and review of other topical reports on age-related degradation and aging management.

In its response dated February 14, 2013, the applicant clarified that the Operating Experience Program requires review of topical reports and does not exclude any topical reports on age-related degradation and aging management. The applicant also stated that, in accordance with the Operating Experience Program, it evaluates all NRC generic communications for applicability to Callaway. As such, the applicant explained that the Operating Experience Program will ensure review of a GALL Report revision if the NRC communicates it in this form. The applicant also stated that, if the NRC does not use a generic communication, the applicant will nonetheless identify issuance of a GALL Report revision through self-assessment and benchmarking activities. The applicant further stated that it expects the plant aging management coordinator and other personnel to identify lessons learned concerning age-related degradation and aging management and to determine if any new information warrants review under the Operating Experience Program. In addition, the applicant stated that a GALL Report revision would likely be publicized in some form of NRC communication, which the aging management coordinator would then use to identify the revision as an additional source of operating experience that needs review.

Through its updates of the GALL Report and issuance of LR-ISGs, the staff has emphasized that these documents contain new information and important lessons learned that are relevant to maintaining the effectiveness of the AMPs and activities. The staff finds the applicant's response acceptable because the applicant acknowledges the importance of evaluating the content of GALL Report revisions to determine impacts to its AMPs. Given the importance of reviewing this information, the applicant described several processes that it will use to make sure a GALL Report revision is entered into the Operating Experience Program and evaluated. As such, the staff finds that the processes described by the applicant are adequate for identifying and evaluating future GALL Report revisions. The staff's concern described in RAI B1.4-1b regarding review of GALL Report revisions as a source of industry operating experience is resolved.

The staff determined that the applicant will implement appropriate processes to consider the impacts of industry operating experience on its AMPs and activities because the applicant's processes will capture NRC and industry guidance documents and standards applicable to aging management, including revisions to the GALL Report. The applicant's consideration of industry guidance documents as operating experience is, therefore, consistent with the guidance in SRP-LR Section A.4.2.

Screening of Incoming Operating Experience. SRP-LR Section A.4.2 states that all incoming plant-specific and industry operating experience should be screened to determine if it involves age-related degradation or impacts to aging management activities. The applicant's responses to RAIs B1.4-1 and B1.4-1a describe several enhancements to ensure that the applicant will effectively screen and evaluate age-related operating experience. In its response to RAI B1.4-1 as supplemented by letter dated December 19, 2012, the applicant stated that it will enhance both the CAP and Operating Experience Program to provide specific direction to identify and

evaluate age-related operating experience. In LRA amendments submitted by letters dated December 19, 2012, and February 14, 2013, the applicant stated that it had completed these enhancements. In addition, in its response to RAIs B1.4-1 and B1.4-1a dated December 19, 2012, the applicant described enhanced training for certain key individuals involved with the operating experience screening and evaluation process. Specifically, the applicant stated that it will enhance the Operating Experience Program coordinator training to ensure the proper review, dissemination, and evaluation of plant-specific and industry operating experience involving age-related degradation. The applicant also explained that plant subject matter experts assist Operating Experience Program coordinators in the screening of external operating experience and participate in operating experience review, evaluation, and documentation. The applicant will require these individuals to participate in initial and continuing training on operating experience and aging concepts. The plant aging management coordinator also will review plant-specific and industry operating experience for lessons learned, and this individual will receive training on license renewal concepts for proficiency in screening and evaluating age-related operating experience. In an amendment to the LRA submitted by letter dated April 26, 2013, the applicant stated that it had completed the training-related enhancements. The staff reviewed these responses and determined that the applicant's operating experience review processes are acceptable because they include screening of operating experience by trained individuals so that items with potential impact to aging management can receive appropriate evaluation. The applicant's screening of plant-specific and industry operating experience is, therefore, consistent with the guidance in SRP-LR Section A.4.2.

Identification of Operating Experience Related to Aging. SRP-LR Section A.4.2 states that coding should be used within the CAP to identify operating experience concerning age-related degradation applicable to the plant, and the associated entries should be periodically reviewed and any adverse trends evaluated. In response to RAI B1.4-1a dated December 19, 2012, the applicant stated that, as an enhancement, it established specific codes within its CAP to assist in the identification and trending of age-related degradation so that it can assess and trend the adequacy of AMPs and make adjustments when necessary. The applicant also stated that, per existing processes, it analyzes CAP records at least semiannually using identification codes and other available data. In addition, the applicant stated that its CAP requires documentation and further evaluation of trends in performance or frequency of occurrence that indicate performance adverse to an expected or established standard. The staff reviewed the response and finds these activities acceptable because the applicant has established means at a programmatic level to identify, trend, and evaluate operating experience that involves age-related degradation. The applicant's identification of age-related operating experience applicant to the plant is, therefore, consistent with the guidance in SRP-LR Section A.4.2.

Information Considered in Operating Experience Evaluations. SRP-LR Section A.4.2 states that operating experience identified as involving aging should receive further evaluation that takes into account information fundamental to an AMR, such as the affected SSCs, materials, environments, aging effects, aging mechanisms, and AMPs. In its response to RAI B1.4-1a dated December 19, 2012, the applicant stated that its evaluations of operating experience related to aging management will consider and document the following: (a) SSCs that are similar or identical to those involved with the identified operating experience issue; (b) materials of construction, operating environments, and aging effects associated with the identified aging issue so that lessons learned can be applied to susceptible SSCs within the scope of license renewal; and (c) aging mechanisms associated with the operating experience to confirm that appropriate programs are in place to manage aging that could be caused by these mechanisms. Additionally, the applicant stated that it will consider and document evaluation of the AMPs

associated with the operating experience so that, if the AMPs have been shown to be ineffective, similar AMPs can be evaluated to determine if changes are appropriate or if a new AMP is needed. These AMP evaluations also include consideration of the activities, criteria, and evaluations integral to the elements of the AMPs. The staff reviewed the response and determined that the applicant's evaluations of age-related operating experience will include assessment of potential impacts to the aging management activities through the consideration of information fundamental to an AMR.

SRP-LR Section A.4.2 also states that actions should be initiated within the CAP to either enhance the AMPs or develop and implement new AMPs if it is found through an operating experience evaluation that the effects of aging may not be adequately managed. In its response to RAI B1.4-1a dated December 19, 2012, the applicant stated that it uses the CAP to address all degraded conditions, which include degraded conditions identified from evaluation of plant-specific operating experience under the CAP and from evaluation of industry operating experience under the Operating Experience Program. In its response the applicant also stated that it will use the processes under the CAP and Operating Experience Program to enhance the AMPs or develop new AMPs when the review of operating experience indicates that the AMPs may not be fully effective. The staff reviewed the response and determined that the applicant will uses its CAP to implement changes necessary to manage the effects of aging, as determined through the evaluation of operating experience.

Therefore, the staff finds that the information considered in the applicant's operating experience evaluations and use of the CAP to ensure that the effects of aging are adequately managed is consistent with the guidance in SRP-LR Section A.4.2.

Evaluation of AMP Implementation Results. SRP-LR Section A.4.2 states that the results of implementing the AMPs, such as data from inspections, tests, and analyses, should be evaluated regardless of whether the acceptance criteria of the particular AMP have been met. SRP-LR Section A.4.2 states that this information should be used to determine if it is necessary to adjust the frequency of future inspections, establish new inspections, and adjust or expand the inspection scope. In addition, SRP-LR Section A.4.2 states that actions should be initiated within the CAP to either enhance the AMPs or develop and implement new AMPs if these evaluations indicate that the effects of aging may not be adequately managed. In its response to RAI B1.4-1a dated December 19, 2012, the applicant stated that it documents the results of AMP inspections, tests, analyses, etc. in its plant work management system. The applicant stated that, if the results do not meet acceptance criteria, it enters the results into the CAP for further review and action, which includes correcting the specific condition and evaluating the adequacy of the AMPs. The applicant also stated that it will periodically monitor and trend AMP performance. This monitoring will include review of satisfactory and unsatisfactory examination and testing results to ensure that aspects of the AMPs are effective, such as the inspection frequency and scope, and if new inspections are needed. In addition, the applicant stated that it will periodically assess AMP performance and effectiveness based on available monitoring and trending data, benchmarking, status of industry initiatives, and operating experience. If it identifies a deficient condition related to aging through these activities, the applicant stated that it will use the CAP to determine if the AMPs should be modified or if new AMPs should be created. The staff reviewed this response and finds the applicant's treatment of AMP implementation results as operating experience acceptable because the applicant will evaluate these results and use the information to determine whether to adjust the aging management inspection activities. The applicant's activities for the evaluation of the AMP implementation results are, therefore, consistent with the guidance in SRP-LR Section A.4.2.

Training. SRP-LR Section A.4.2 states that training on age-related degradation and aging management should be provided to those personnel responsible for implementing the AMPs and those personnel that may submit, screen, assign, evaluate, or otherwise process plant-specific and industry operating experience. SRP-LR Section A.4.2 also states that the training should occur on a periodic basis and include provisions to accommodate the turnover of plant personnel.

In its response to RAI B1.4-1a dated December 19, 2012, the applicant described its training activities for key personnel involved with the processing and evaluation of operating experience. The applicant stated that its Operating Experience Program coordinators are the central input for all operating experience at the plant. As an enhancement, the applicant stated that it will update their training to ensure the proper review and dissemination of plant-specific and industry operating experience concerning age-related degradation. The applicant also stated that the Operating Experience Program coordinators rely on various subject-matter experts to assist with operating experience screening, evaluation, and documentation. For these individuals, the applicant provides initial training on operating experience and aging concepts. The applicant also will include specific modules on aging concepts, identification of aging mechanisms, and review of operating experience in its continuing training. In addition, the applicant stated that it will assign an aging management coordinator before or upon receipt of the renewed operating license to oversee implementation of the license renewal activities. This coordinator will review operating experience to identify applicable lessons learned and plant-specific operating experience related to aging that will be shared with the industry. The applicant stated that the aging management coordinator will receive training on license renewal concepts for proficiency in screening and evaluating age-related operating experience. The aging management coordinator also will attend the same initial and continuing training on aging topics as required of the subject-matter experts. The applicant further stated that the AMP owners have received classroom training on component aging. As an enhancement, the applicant stated that it will require the AMP owners to take periodic training on relevant operating experience and aging concepts. New AMP owners will be required to take the same training, and the applicant will ensure the effective turnover of responsibilities through procedures for program and personnel transitions. In an amendment to the LRA submitted by letter dated April 26, 2013, the applicant stated that it had completed the training-related enhancements.

The staff reviewed the applicant's response and finds the training activities acceptable because the applicant will require initial and periodic training on age-related degradation and aging management topics for the personnel responsible for implementing the AMPs and for the key personnel responsible for processing and evaluating operating experience related to aging. The staff also finds that the applicant's training approach will address personnel turnover because the applicant will require training on a position-specific basis, and individuals new to the positions will receive initial training on age-related concepts. The applicant's training activities are, therefore, consistent with the guidance in SRP-LR Section A.4.2.

Reporting Operating Experience to the Industry. SRP-LR Section A.4.2 states that guidelines should be established for reporting plant-specific operating experience on age-related degradation and aging management to the industry. In its response to RAI B1.4-1 as supplemented by letter dated December 19, 2012, the applicant stated that it will enhance the Operating Experience Program to include direction and criteria for reporting plant-specific operating experience concerning age-related degradation to other licensees. In an amendment to the LRA submitted by letter dated December 19, 2012, the applicant stated that it had completed this enhancement. The applicant's reporting criteria include observation of

age-related degradation significantly beyond that expected, aging effects or mechanisms not previously discovered by or managed by the applicant's AMPs, and significant changes to the applicant's AMPs that would be of interest to other licensees. The staff reviewed the response and finds the applicant's reporting guidelines acceptable because they specifically cover circumstances in which noteworthy plant-specific operating experience related to aging management and age-related degradation will be reported to the industry. The applicant's establishment of these reporting guidelines is, therefore, consistent with the guidance in SRP-LR Section A.4.2.

Schedule for Implementing the Operating Experience Review Activities. SRP-LR Section A.4.2 states that any enhancements to the existing operating experience review activities should be put in place no later than the date when the renewed operating license is issued. In RAIs B1.4-1a and B1.4-1b, issued by letters dated December 7, 2012, and January 30, 2013, respectively, the staff requested the applicant to identify any such enhancements and to provide a schedule for their implementation, including a justification if the implementation date is later than the date when the renewed operating license is scheduled to be issued, if approved. In its response to RAI B1.4-1, as revised in response to B1.4-1a dated December 19, 2012, the applicant identified several enhancements to the CAP and Operating Experience Program. In its response to RAI B1.4-1b dated February 14, 2013, the applicant identified no additional enhancements. Subsequently, in amendment to the LRA submitted by letter dated April 26, 2013, the applicant stated that it completed all of the enhancements. The staff reviewed the responses and finds the applicant's schedule for implementing these programmatic enhancements acceptable because the applicant completed implementation before issuance of the renewed license, which is consistent with the guidance in SRP-LR Section A.4.2.

SRP-LR Section A.4.2 also states that the operating experience review activities should be implemented on an ongoing basis throughout the term of the renewed license. By letter dated September 6, 2012, as revised by letters dated December 19, 2012, February 14, 2013, and April 26, 2013, the applicant amended the FSAR supplement in LRA Appendix A to include a summary description of the ongoing operating experience review activities. 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 license 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 obligated to conduct its operating experience review activities accordingly. The staff finds the implementation schedule acceptable because the applicant will implement the enhanced operating experience review activities on an ongoing basis throughout the term of the renewed operating license. This ongoing implementation is, therefore, consistent with the guidance in SRP-LR Section A.4.2.

3.0.5.2.5 Summary

Based on its review of the LRA and the applicant's responses to RAIs B1.4-1, B1.4-1a, and B1.4-1b, the staff determined that the applicant's programmatic activities for the ongoing review of operating experience are consistent with the guidance in SRP-LR Section A.4.2 as established in LR-ISG-2011-05. These activities are, therefore, acceptable for (a) 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) the enhancement of AMPs or development of new AMPs when it is determined through the evaluation of operating experience that the effects of aging may not be

adequately managed. The staff's concerns described in RAIs B1.4-1, B1.4-1a, and B1.4-1b are resolved.

3.0.5.3 FSAR Supplement

SRP-LR Section A.4.2 states that the programmatic activities for the ongoing review of plant-specific and industry operating experience concerning age-related degradation and aging management should be described in the FSAR supplement. The staff reviewed the applicant's FSAR supplement provided in LRA Appendix A. The staff found that Commitment No. 2 in LRA Table A4-1 is associated with the ongoing operating experience review activities; however, the staff determined that the applicant did not provide a complete summary description of these activities. By letter dated August 6, 2012, the staff issued RAI B1.4-1 which requested in part that the applicant provide a full summary description to address the requirements of 10 CFR 54.21(d).

In its response dated September 6, 2012, the applicant amended LRA Section A1 to include a summary description of its programmatic activities for the ongoing review of operating experience. The applicant also revised Commitment No. 2 to identify license renewal enhancements to its existing operating experience review activities. The applicant subsequently revised this commitment based on its response to RAI B1.4-1a dated December 19, 2012. In response to RAI B1.4-1b dated February 14, 2013, the applicant further revised Commitment No. 2 to remove a statement that qualified that its processes only include review of certain industry guidance documents, such as GALL Report revision, if communicated in an NRC generic communication. In an amendment to the LRA submitted by letter dated April 26, 2013, the applicant also revised the commitment to indicate that all of the enhancements were completed.

LR-ISG-2011-05 revises SRP-LR Table 3.0-1 by including an example summary description for the programmatic activities for the ongoing review of operating experience. The staff reviewed the content of the applicant's summary description, as provided by letter dated September 6, 2012, and revised by letters dated December 19, 2012, February 14, 2013, and April 26, 2013, against the content in the example from SRP-LR Table 3.0-1. The staff determined that the content of the applicant's summary description is consistent with this example and also sufficiently comprehensive to describe the applicant's programmatic operating experience review activities for license renewal. Therefore, the staff's concern described in RAI B1.4-1 is resolved and the staff finds the applicant's FSAR supplement summary description acceptable.

3.0.5.4 Conclusion

Based on its review of the applicant's programmatic activities for the ongoing review of operating experience, as described in the LRA and in response to RAIs B1.4-1, B1.4-1a, and B1.4-1b, the staff concludes that the applicant has demonstrated that operating experience will be reviewed to ensure that the effects of aging 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 also reviewed the FSAR 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 reactor vessel, RVIs, and RCS components and component groups of the following:

- reactor vessel
- RVIs
- RCS
- pressurizer
- steam generators

3.1.1 Summary of Technical Information in the Application

LRA Section 3.1 provides AMR results for the reactor vessel, RVIs, RCS components and components groups. LRA Table 3.1-1, "Summary of Aging Management Programs 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 reactor vessel, RVIs, and RCS components and component groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included issue reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.1.2 Staff Evaluation

The staff reviewed LRA Section 3.1 to determine if the applicant provided sufficient information to demonstrate that the effects of aging for the reactor vessel, RVIs, and RCS components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) 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 of the applicant's AMPs to ensure the applicant's claim that certain AMPs were consistent with the GALL Report. The purpose of this audit was to examine the applicant's AMPs and related documentation and to confirm the applicant's claim of consistency with the corresponding GALL Report AMPs. The staff did not repeat its review of the matters described in the GALL Report. The staff's evaluations of the AMPs are documented in SER Section 3.0.3.

The staff reviewed the AMRs to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did confirm that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. Details of the staff's evaluation are discussed in SER Sections 3.1.2.1.

During its review, the staff also selected AMRs consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations are consistent with the SRP-LR Section 3.1.2.2 acceptance criteria. The staff's evaluations are documented in SER Section 3.1.2.2.

The staff also reviewed the AMRs not consistent with or not addressed in the GALL Report. The 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.

The staff's review of the reactor vessel, RVIs, and RCS component groups followed several approaches. One approach, documented in SER Section 3.1.2.1, discusses the staff's review of AMR results for components the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.1.2.2, discusses the staff's review of AMR results for components the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.1.2.3, discusses the staff's review of AMR results for components the applicant indicated are not consistent with or not addressed in the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the reactor vessel, RVIs, and RCS components is documented in SER Section 3.0.3.

Table 3.1-1 Staff Evaluation for Reactor Vessel, RVIs, RCS Components in the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
High strength, low-alloy steel top head closure stud assembly exposed to air with potential for reactor coolant leakage (3.1.1-1)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA evaluated for the period of extended operation (See SRP, Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes, TLAA	TLAA	Consistent with the GALL Report (see SER Section 3.1.2.2.1)
Nickel alloy tubes and sleeves exposed to reactor coolant and secondary feedwater or steam (3.1.1-2)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA evaluated for the period of extended operation (See SRP, Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes, TLAA	TLAA	Consistent with the GALL Report (see SER Section 3.1.2.2.1)
Stainless steel or nickel alloy RVI components exposed to reactor coolant and neutron flux (3.1.1-3)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA evaluated for the period of extended operation (See SRP, Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes, TLAA	TLAA	Consistent with the GALL Report (see SER Section 3.1.2.2.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel pressure vessel support skirt and attachment welds (3.1.1-4)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA evaluated for the period of extended operation (See SRP, Section 4.3 “Metal Fatigue,” for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes, TLAA	Not applicable	Not applicable to Callaway (see SER Section 3.1.2.2.1)
Steel, stainless steel, or steel (with stainless steel or nickel alloy cladding) steam generator components, pressurizer relief tank components or piping components or bolting (3.1.1-5)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA evaluated for the period of extended operation (See SRP, Section 4.3 “Metal Fatigue,” for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes, TLAA	TLAA	Consistent with the GALL Report (see SER Section 3.1.2.2.1)
Steel (with or without nickel-alloy or stainless steel cladding), or stainless steel; or nickel alloy reactor coolant pressure boundary components: piping, piping components, and piping elements exposed to reactor coolant (3.1.1-6)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA evaluated for the period of extended operation, and for Class 1 components environmental effects on fatigue are to be addressed (See SRP, Section 4.3 “Metal Fatigue,” for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes, TLAA	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.1)
Steel (with or without nickel-alloy or stainless steel cladding), or stainless steel; or nickel alloy reactor vessel components: flanges; nozzles; penetrations; safe ends; thermal sleeves; vessel shells, heads and welds exposed to reactor coolant (3.1.1-7)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA evaluated for the period of extended operation, and for Class 1 components environmental effects on fatigue are to be addressed (see SRP, Section 4.3 “Metal Fatigue,” for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes, TLAA	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel (with or without nickel-alloy or stainless steel cladding), or stainless steel; or nickel alloy steam generator components exposed to reactor coolant (3.1.1-8)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA evaluated for the period of extended operation, and for Class 1 components environmental effects on fatigue are to be addressed (see SRP, Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes, TLAA	TLAA	Consistent with the GALL Report (see SER Section 3.1.2.2.1)
Steel (with or without nickel-alloy or stainless steel cladding), stainless steel; nickel alloy RCPB piping; flanges; nozzles & safe ends; pressurizer shell heads & welds; heater sheaths & sleeves; penetrations; thermal sleeves exposed to reactor coolant (3.1.1-9)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA evaluated for the period of extended operation, and for Class 1 components environmental effects on fatigue are to be addressed (see SRP, Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes, TLAA	TLAA	Consistent with GALL Report (see SER Section 3.1.2.2.1)
Steel (with or without nickel-alloy or stainless steel cladding), stainless steel; nickel alloy reactor vessel flanges; nozzles; penetrations; pressure housings; safe ends; thermal sleeves; vessel shells, heads and welds exposed to reactor coolant (3.1.1-10)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA evaluated for the period of extended operation, and for Class 1 components environmental effects on fatigue are to be addressed (see SRP, Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes, TLAA	TLAA	Consistent with the GALL Report (see SER Section 3.1.2.2.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel or stainless steel pump and valve closure bolting exposed to high temperatures and thermal cycles (3.1.1-11)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA evaluated for the period of extended operation; check ASME Code limits for allowable cycles (less than 7,000 cycles) of thermal stress range (see SRP Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes, TLAA	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Steel steam generator components: upper and lower shells, transition cone; new transition cone closure weld exposed to secondary feedwater or steam (3.1.1-12)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and Chapter XI.M2, "Water Chemistry," and, for Westinghouse Model 44 and 51 S/G, if corrosion of the shell is found, additional inspection procedures are developed	Yes	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry	Consistent with the GALL Report (see SER Sections 3.1.2.2.2(1) and 3.1.2.2.2(2))
Steel (with or without stainless steel cladding) reactor vessel beltline shell, nozzles, and welds exposed to reactor coolant and neutron flux (3.1.1-13)	Loss of fracture toughness caused by neutron irradiation embrittlement	TLAA is to be evaluated in accordance with Appendix G of 10 CFR Part 50 and Regulatory Guide (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	Consistent with the GALL Report (see SER Section 3.1.2.2.3(1))
Steel (with or without cladding) reactor vessel beltline shell, nozzles, and welds; safety injection nozzles (3.1.1-14)	Loss of fracture toughness caused by neutron irradiation embrittlement	Chapter XI.M31, "Reactor Vessel Surveillance"	Yes	Reactor Vessel Surveillance	Consistent with the GALL Report (see SER Section 3.1.2.2.3(2))

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel alloy RVI components exposed to reactor coolant and neutron flux (3.1.1-15)	Reduction in ductility and fracture toughness caused by neutron irradiation	Ductility - Reduction in Fracture Toughness is a TLAA to be evaluated for the period of extended operation (see SRP, Section 4.7, “Other Plant-Specific TLAAs,” for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1))	Yes, TLAA	TLAA	Consistent with the GALL Report (see SER Section 3.1.2.2.3(3))
Stainless steel and nickel alloy top head enclosure vessel flange leak detection line (3.1.1-16)	Cracking caused by stress corrosion cracking, intergranular stress corrosion cracking	A plant-specific AMP is to be evaluated because existing programs may not be capable of mitigating or detecting crack initiation and growth caused by SCC in the vessel flange leak detection line	Yes, plant-specific	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.4(1))
Stainless steel isolation condenser components exposed to reactor coolant (3.1.1-17)	Cracking caused by stress corrosion cracking, intergranular stress corrosion cracking	Chapter XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD” for Class 1 components, and Chapter XI.M2, “Water Chemistry” for BWR water, and a plant-specific verification program	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.4(2))
Reactor vessel shell fabricated of SA508-Cl 2 forgings clad with stainless steel using a high-heat-input welding process exposed to reactor coolant (3.1.1-18)	Crack growth caused by cyclic loading	Growth of intergranular separations is a TLAA evaluated for the period of extended operation (see SRP, Section 4.7, “Other Plant-Specific TLAAs,” for acceptable methods for meeting the requirements of 10 CFR 54.21(c))	Yes, TLAA	TLAA	Consistent with the GALL Report (see SER Section 3.1.2.2.5)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel reactor vessel closure head flange leak-detection line and bottom-mounted instrument guide tubes (external to reactor vessel) (3.1.1-19)	Cracking caused by stress corrosion cracking	A plant-specific AMP is to be evaluated	Yes, plant-specific	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry	Consistent with the GALL Report (see SER Section 3.1.2.2.6(1))
Cast austenitic stainless steel Class 1 piping, piping components, and piping elements exposed to reactor coolant (3.1.1-20)	Cracking caused by stress corrosion cracking	Chapter XI.M2, "Water Chemistry" and, for CASS components that do not meet the NUREG-0313 guidelines, a plant specific AMP	Yes	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry	Consistent with the GALL Report (see SER Section 3.1.2.2.6(2))
Steel and stainless steel isolation condenser components exposed to reactor coolant (3.1.1-21)	Cracking caused by cyclic loading	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components. The ISI program is to be augmented by a plant-specific verification program	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.7)
Steel steam generator feedwater impingement plate and support exposed to secondary feedwater (3.1.1-22)	Loss of material caused by erosion	A plant-specific AMP is to be evaluated	Yes, plant-specific	Not applicable	Not applicable to Callaway (see SER Section 3.1.2.2.8)
Stainless steel or nickel alloy PWR RVI components (inaccessible locations) exposed to reactor coolant and neutron flux (3.1.1-23)	Cracking caused by stress corrosion cracking and irradiation-assisted stress corrosion cracking	Chapter XI.M16A, "PWR Vessel Internals," and Chapter XI.M2, "Water Chemistry"	Yes	PWR Vessel Internals	Consistent with the GALL Report (see SER Section 3.1.2.2.9)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel or nickel alloy PWR RVI components (inaccessible locations) exposed to reactor coolant and neutron flux (3.1.1-24)	Loss of fracture toughness caused by neutron irradiation embrittlement; or changes in dimension caused by void swelling; or loss of preload caused by thermal and irradiation enhanced stress relaxation; or loss of material caused by wear	Chapter XI.M16A, "PWR Vessel Internals"	Yes	PWR Vessel Internals	Consistent with the GALL Report (see SER Section 3.1.2.2.10)
Steel (with nickel-alloy cladding) or nickel alloy steam generator primary side components: divider plate and tube-to-tube sheet welds exposed to reactor coolant (3.1.1-25)	Cracking caused by primary water stress corrosion cracking	Chapter XI.M2, "Water Chemistry"	Yes, plant-specific	Commitments to confirm integrity of the welds	Consistent with the GALL Report (see SER Sections 3.1.2.2.11(1) and 3.1.2.2.11(2))
Stainless steel combustion engineering core support barrel assembly: lower flange weld exposed to reactor coolant and neutron flux. upper internals assembly: fuel alignment plate (applicable to plants with core shrouds assembled with full height shroud plates) exposed to reactor coolant and neutron flux. lower support structure: core support plate (applicable to plants with a core support plate) exposed to reactor coolant and neutron flux (3.1.1-26)	Cracking caused by fatigue	Chapter XI.M16A, "PWR Vessel Internals," and Chapter XI.M2, "Water Chemistry," if fatigue life cannot be confirmed by TLAA	Yes	Not applicable	Not applicable to Callaway (see SER Section 3.1.2.2.12)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Nickel alloy Westinghouse control rod guide tube assemblies, guide tube support pins exposed to reactor coolant and neutron flux (3.1.1-27)	Cracking caused by stress corrosion cracking and fatigue	A plant-specific AMP is to be evaluated	Yes, plant-specific	Not applicable	Not applicable to Callaway (see SER Section 3.1.2.2.13)
Nickel alloy Westinghouse control rod guide tube assemblies, guide tube support pins, and Zircaloy-4 Combustion Engineering incore instrumentation thimble tubes exposed to reactor coolant and neutron flux (3.1.1-28)	Loss of material caused by wear	A plant-specific AMP is to be evaluated	Yes, plant-specific	Not applicable	Not applicable to Callaway (see SER Section 3.1.2.2.14)
Nickel alloy core shroud and core plate access hole cover (welded covers) exposed to reactor coolant (3.1.1-29)	Cracking caused by stress corrosion cracking, intergranular stress corrosion cracking, irradiation-assisted stress corrosion cracking	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and Chapter XI.M2, "Water Chemistry," and for BWRs with a crevice in the access hole covers, augmented inspection using UT or other acceptable techniques	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel or nickel alloy penetration: drain line exposed to reactor coolant (3.1.1-30)	Cracking caused by stress corrosion cracking, intergranular stress corrosion cracking, cyclic loading	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Steel and stainless steel isolation condenser components exposed to reactor coolant (3.1.1-31)	Loss of material caused by general (steel only), pitting, and crevice corrosion	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, nickel alloy, or CASS RVIs, core support structure, exposed to reactor coolant and neutron flux (3.1.1-32)	Cracking, or loss of material caused by wear	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Consistent with the GALL Report (See SER Section 3.1.2.1.3)
Stainless steel, steel with stainless steel cladding Class 1 reactor coolant pressure boundary components exposed to reactor coolant (3.1.1-33)	Cracking caused by stress corrosion cracking	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for ASME components, and Chapter XI.M2, "Water Chemistry"	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry	Consistent with the GALL Report
Stainless steel, steel with stainless steel cladding pressurizer relief tank (tank shell and heads, flanges, nozzles) exposed to treated borated water >60 °C (>140 °F) (3.1.1-34)	Cracking caused by stress corrosion cracking	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for ASME components, and Chapter XI.M2, "Water Chemistry"	No	NA	Not applicable to Callaway (see SER Section 3.1.2.1.1)
Stainless steel, steel with stainless steel cladding RCS cold leg, hot leg, surge line, and spray line piping and fittings exposed to reactor coolant (3.1.1-35)	Cracking caused by cyclic loading	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components	No,	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Consistent with the GALL Report
Steel, stainless steel pressurizer integral support exposed to air with metal temperature up to 288 °C (550 °F) (3.1.1-36)	Cracking caused by cyclic loading	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Consistent with the GALL Report
Steel reactor vessel flange (3.1.1-37)	Loss of material caused by wear	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Cast austenitic stainless steel Class 1 pump casings, and valve bodies and bonnets exposed to reactor coolant >250° C (>482° F) (3.1.1-38)	Loss of fracture toughness caused by thermal aging embrittlement	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components. For pump casings and valve bodies, screening for susceptibility to thermal aging is not necessary.	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Consistent with the GALL Report
Steel, stainless steel, or steel with stainless steel cladding Class 1 piping, fittings and branch connections <NPS 4 exposed to reactor coolant (3.1.1-39)	Cracking caused by stress corrosion cracking, intergranular stress corrosion cracking (for stainless steel only), and thermal, mechanical, and vibratory loading	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components, Chapter XI.M2, "Water Chemistry," and XI.M35, "One-Time Inspection of ASME Code Class 1 Small-bore Piping"	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, Water Chemistry, and One-Time Inspection of ASME Code Class 1 Small bore Piping	Consistent with the GALL Report
Steel with stainless steel or nickel alloy cladding; or stainless steel pressurizer components exposed to reactor coolant (3.1.1-40)	Cracking caused by cyclic loading	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components, and Chapter XI.M2, "Water Chemistry"	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry	Consistent with the GALL Report
Nickel alloy core support pads; core guide lugs exposed to reactor coolant (3.1.1-40a)	Cracking caused by primary water stress corrosion cracking	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components, and Chapter XI.M2, "Water Chemistry"	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry	Consistent with the GALL Report
Nickel alloy core shroud and core plate access hole cover (mechanical covers) exposed to reactor coolant (3.1.1-41)	Cracking caused by stress corrosion cracking, intergranular stress corrosion cracking, irradiation-assisted stress corrosion cracking	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components, and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel with stainless steel or nickel alloy cladding or stainless steel primary side components; steam generator upper and lower heads, and tube sheet weld; or pressurizer components exposed to reactor coolant (3.1.1-42)	Cracking caused by stress corrosion cracking, primary water stress corrosion cracking	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components, and Chapter XI.M2, "Water Chemistry"	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry	Consistent with the GALL Report
Stainless steel and nickel-alloy RVIs exposed to reactor coolant (3.1.1-43)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components, and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Steel steam generator secondary manways and handholds (cover only) exposed to air with leaking secondary-side water and/or steam (3.1.1-44)	Loss of material caused by erosion	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 2 components	No	Not applicable	Not applicable to Callaway (see SER Section 3.1.2.1.1)
Nickel alloy and steel with nickel-alloy cladding reactor coolant pressure boundary components exposed to reactor coolant (3.1.1-45)	Cracking caused by primary water stress corrosion cracking	Chapter XI.M1, "ASME Section XI ISI, IWB, IWC & IWD," and Chapter XI.M2, "Water Chemistry," and, for nickel-alloy, Chapter XI.M11B, "Cracking of Nickel-Alloy Components and Loss of Material due to Boric Acid-induced Corrosion in RCPB Components (PWRs Only)"	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD, Water Chemistry, and Cracking of Nickel-Alloy Components and Loss of Material due to Boric Acid induced Corrosion in RCPB Components	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, nickel-alloy, nickel-alloy welds and/or buttering control rod drive head penetration pressure housing or nozzles safe ends and welds (inlet, outlet, safety injection) exposed to reactor coolant (3.1.1-46)	Cracking caused by stress corrosion cracking, primary water stress corrosion cracking	Chapter XI.M1, "ASME Section XI ISI, IWB, IWC & IWD," and Chapter XI.M2, "Water Chemistry," and, for nickel-alloy, Chapter XI.M11B, "Cracking of Nickel-Alloy Components and Loss of Material due to Boric Acid-induced corrosion in RCPB Components (PWRs Only)"	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD, Water Chemistry, and Cracking of Nickel-Alloy Components and Loss of Material due to Boric Acid induced Corrosion in RCPB Components	Consistent with the GALL Report
Stainless steel, nickel-alloy control rod drive head penetration pressure housing exposed to reactor coolant (3.1.1-47)	Cracking caused by stress corrosion cracking, primary water stress corrosion cracking	Chapter XI.M1, "ASME Section XI ISI, IWB, IWC & IWD," and Chapter XI.M2, "Water Chemistry"	No	ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD and Water Chemistry	Consistent with the GALL Report
Steel external surfaces: reactor vessel top head, reactor vessel bottom head, reactor coolant pressure boundary piping or components adjacent to dissimilar metal (Alloy 82/182) welds exposed to air with borated water leakage (3.1.1-48)	Loss of material caused by boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion," and Chapter XI.M11B, "Cracking of Nickel-Alloy Components and Loss of Material due to Boric Acid-Induced Corrosion in RCPB Components (PWRs Only)"	No	Boric Acid Corrosion, and Cracking of Nickel-Alloy Components and Loss of Material due to Boric Acid-Induced Corrosion in RCPB Components	Consistent with the GALL Report
Steel reactor coolant pressure boundary external surfaces or closure bolting exposed to air with borated water leakage (3.1.1-49)	Loss of material caused by boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion"	No	Boric Acid Corrosion	Consistent with the GALL Report
Cast austenitic stainless steel Class 1 piping, piping component, and piping elements and control rod drive pressure housings exposed to reactor coolant >250° C (>482° F) (3.1.1-50)	Loss of fracture toughness caused by thermal aging embrittlement	Chapter XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)"	No	Not applicable	Not applicable to Callaway (see SER Section 3.1.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel or nickel-alloy Babcock & Wilcox reactor internal components exposed to reactor coolant and neutron flux (3.1.1-51)	Cracking caused by stress corrosion cracking, irradiation-assisted stress corrosion cracking, or fatigue	Chapter XI.M16A, "PWR Vessel Internals," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to Callaway (see SER Section 3.1.2.1.1)
Stainless steel or nickel-alloy Combustion Engineering reactor internal components exposed to reactor coolant and neutron flux (3.1.1-52)	Cracking caused by stress corrosion cracking, irradiation-assisted stress corrosion cracking, or fatigue	Chapter XI.M16A, "PWR Vessel Internals," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to Callaway (see SER Section 3.1.2.1.1)
Stainless steel or nickel-alloy Westinghouse reactor internal components exposed to reactor coolant and neutron flux (3.1.1-53)	Cracking caused by stress corrosion cracking, irradiation-assisted stress corrosion cracking, or fatigue	Chapter XI.M16A, "PWR Vessel Internals," and Chapter XI.M2, "Water Chemistry"	No	PWR Vessel Internals and Water Chemistry	Consistent with the GALL Report (see SER Section 3.1.2.1.3)
Stainless steel bottom mounted instrument system flux thimble tubes (with or without chrome plating) exposed to reactor coolant and neutron flux (3.1.1-54)	Loss of material caused by wear	Chapter XI.M16A, "PWR Vessel Internals," and Chapter XI.M37, "Flux Thimble Tube Inspection"	No	PWR Vessel Internals and Flux Thimble Tube Inspection	Consistent with the GALL Report
Stainless steel thermal shield assembly, thermal shield flexures exposed to reactor coolant and neutron flux (3.1.1-55)	Cracking caused by fatigue; loss of material caused by wear	Chapter XI.M16A, "PWR Vessel Internals"	No	Not applicable	Not applicable to Callaway (see SER Section 3.1.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel or nickel-alloy Combustion Engineering reactor internal components exposed to reactor coolant and neutron flux (3.1.1-56)	Loss of fracture toughness caused by neutron irradiation embrittlement; or changes in dimension caused by void swelling; or loss of preload caused by thermal and irradiation enhanced stress relaxation; or loss of material caused by wear	Chapter XI.M16A, "PWR Vessel Internals"	No	Not applicable	Not applicable to Callaway (see SER Section 3.1.2.1.1)
Stainless steel or nickel-alloy Babcock & Wilcox reactor internal components exposed to reactor coolant and neutron flux (3.1.1-58)	Loss of fracture toughness caused by neutron irradiation embrittlement; or changes in dimension caused by void swelling; or loss of preload caused by thermal and irradiation enhanced stress relaxation; or loss of material caused by wear	Chapter XI.M16A, "PWR Vessel Internals"	No	Not applicable	Not applicable to Callaway (see SER Section 3.1.2.1.1)
Stainless steel or nickel-alloy Westinghouse reactor internal components exposed to reactor coolant and neutron flux (3.1.1-59)	Loss of fracture toughness caused by neutron irradiation embrittlement; or changes in dimension caused by void swelling; or loss of preload caused by thermal and irradiation enhanced stress relaxation; or loss of material caused by wear	Chapter XI.M16A, "PWR Vessel Internals"	No	PWR Vessel Internals	Consistent with the GALL Report (see SER Section 3.1.2.1.3)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to reactor coolant (3.1.1-60)	Wall thinning caused by flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Steel steam generator steam nozzle and safe end, feedwater nozzle and safe end, AFW nozzles and safe ends exposed to secondary feedwater/steam (3.1.1-61)	Wall thinning caused by flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No	Flow-Accelerated Corrosion	Consistent with the GALL Report
High-strength, low alloy steel, or stainless steel closure bolting; stainless steel control rod drive head penetration flange bolting exposed to air with reactor coolant leakage (3.1.1-62)	Cracking caused by stress corrosion cracking	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity	Consistent with the GALL Report
Steel or stainless steel closure bolting exposed to air with reactor coolant leakage (3.1.1-63)	Loss of material caused by general (steel only), pitting, and crevice corrosion or wear	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Steel closure bolting exposed to air – indoor uncontrolled (3.1.1-64)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	Not applicable to Callaway (see SER Section 3.1.2.1.1)
Stainless steel control rod drive head penetration flange bolting exposed to air with reactor coolant leakage (3.1.1-65)	Loss of material caused by wear	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	Not applicable to Callaway (see SER Section 3.1.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
High-strength, low alloy steel, or stainless steel closure bolting; stainless steel control rod drive head penetration flange bolting exposed to air with reactor coolant leakage (3.1.1-66)	Loss of preload caused by thermal effects, gasket creep, and self-loosening	Chapter XI.M18, “Bolting Integrity”	No	Bolting Integrity	Consistent with the GALL Report
Steel or stainless steel closure bolting exposed to air – indoor with potential for reactor coolant leakage (3.1.1-67)	Loss of preload caused by thermal effects, gasket creep, and self-loosening	Chapter XI.M18, “Bolting Integrity”	No	Bolting Integrity	Consistent with the GALL Report
Nickel alloy steam generator tubes exposed to secondary feedwater or steam (3.1.1-68)	Changes in dimension (“denting”) caused by corrosion of carbon steel tube support plate	Chapter XI.M19, “Steam Generators,” and Chapter XI.M2, “Water Chemistry”	No	Not applicable	Not applicable to Callaway (see SER Section 3.1.2.1.1)
Nickel alloy steam generator tubes and sleeves exposed to secondary feedwater or steam (3.1.1-69)	Cracking caused by outer diameter stress corrosion cracking and intergranular attack	Chapter XI.M19, “Steam Generators,” and Chapter XI.M2, “Water Chemistry”	No	Steam Generators and Water Chemistry	Consistent with the GALL Report
Nickel alloy steam generator tubes, repair sleeves, and tube plugs exposed to reactor coolant (3.1.1-70)	Cracking caused by primary water stress corrosion cracking	Chapter XI.M19, “Steam Generators,” and Chapter XI.M2, “Water Chemistry”	No	Steam Generators and Water Chemistry	Consistent with the GALL Report
Steel, chrome plated steel, stainless steel, nickel alloy steam generator U-bend supports including anti-vibration bars exposed to secondary feedwater or steam (3.1.1-71)	Cracking caused by stress corrosion cracking or other mechanism(s); loss of material caused by general (steel only), pitting, and crevice corrosion	Chapter XI.M19, “Steam Generators,” and Chapter XI.M2, “Water Chemistry”	No	Steam Generators and Water Chemistry	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel steam generator tube support plate, tube bundle wrapper, supports, and mounting hardware exposed to secondary feedwater or steam (3.1.1-72)	Loss of material caused by erosion, general, pitting, and crevice corrosion, ligament cracking caused by corrosion	Chapter XI.M19, "Steam Generators," and Chapter XI.M2, "Water Chemistry"	No	Steam Generators and Water Chemistry	Consistent with the GALL Report
Nickel alloy steam generator tubes and sleeves exposed to phosphate chemistry in secondary feedwater or steam (3.1.1-73)	Loss of material caused by wastage and pitting corrosion	Chapter XI.M19, "Steam Generators," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to Callaway (see SER Section 3.1.2.1.1)
Steel steam generator upper assembly and separators including feedwater inlet ring and support exposed to secondary feedwater or steam (3.1.1-74)	Wall thinning caused by flow-accelerated corrosion	Chapter XI.M19, "Steam Generators," and Chapter XI.M2, "Water Chemistry"	No	Steam Generators and Water Chemistry	Consistent with the GALL Report
Steel steam generator tube support lattice bars exposed to secondary feedwater or steam (3.1.1-75)	Wall thinning caused by flow-accelerated corrosion and general corrosion	Chapter XI.M19, "Steam Generators," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to Callaway (see SER Section 3.1.2.1.1)
Steel, chrome plated steel, stainless steel, nickel alloy steam generator U-bend supports including anti-vibration bars exposed to secondary feedwater or steam (3.1.1-76)	Loss of material caused by fretting	Chapter XI.M19, "Steam Generators"	No	Steam Generators	Consistent with the GALL Report
Nickel alloy steam generator tubes and sleeves exposed to secondary feedwater or steam (3.1.1-77)	Loss of material caused by wear and fretting	Chapter XI.M19, "Steam Generators"	No	Steam Generators	Consistent with the GALL Report
Nickel alloy steam generator components such as secondary side nozzles (vent, drain, and instrumentation) exposed to secondary feedwater or steam (3.1.1-78)	Cracking caused by stress corrosion cracking	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection," or Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD."	No	Not applicable	Not applicable to Callaway (see SER Section 3.1.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel; steel with nickel-alloy or stainless steel cladding; and nickel-alloy reactor coolant pressure boundary components exposed to reactor coolant (3.1.1-79)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel or steel with stainless steel cladding pressurizer relief tank: tank shell and heads, flanges, nozzles (none-ASME Section XI components) exposed to treated borated water >60 °C (>140 °F) (3.1.1-80)	Cracking caused by stress corrosion cracking	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report
Stainless steel pressurizer spray head exposed to reactor coolant (3.1.1-81)	Cracking caused by stress corrosion cracking	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report
Nickel alloy pressurizer spray head exposed to reactor coolant (3.1.1-82)	Cracking caused by stress corrosion cracking, primary water stress corrosion cracking	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to Callaway (see SER Section 3.1.2.1.1)
Steel steam generator shell assembly exposed to secondary feedwater or steam (3.1.1-83)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to Callaway (see SER Section 3.1.2.1.1)
Steel top head enclosure (without cladding) top head nozzles (vent, top head spray or RCIC, and spare) exposed to reactor coolant (3.1.1-84)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, nickel-alloy, and steel with nickel-alloy or stainless steel cladding reactor vessel flanges, nozzles, penetrations, safe ends, vessel shells, heads and welds exposed to reactor coolant (3.1.1-85)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel steam generator primary side divider plate exposed to reactor coolant (3.1.1-86)	Cracking caused by stress corrosion cracking	Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to Callaway (see SER Section 3.1.2.1.1)
Stainless steel or nickel-alloy PWR reactor internal components exposed to reactor coolant and neutron flux (3.1.1-87)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry"	No	Water Chemistry	Consistent with the GALL Report (see SER Section 3.1.2.1.4)
Stainless steel; steel with nickel-alloy or stainless steel cladding; and nickel-alloy reactor coolant pressure boundary components exposed to reactor coolant (3.1.1-88)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry"	No	Water Chemistry	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to closed cycle cooling water (3.1.1-89)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Closed Treated Water Systems	Consistent with the GALL Report
Copper-alloy piping, piping components, and piping elements exposed to closed cycle cooling water (3.1.1-90)	Loss of material caused by pitting, crevice, and galvanic corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Closed Treated Water Systems	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
High-strength low alloy steel closure head stud assembly exposed to air with potential for reactor coolant leakage (3.1.1-91)	Cracking caused by stress corrosion cracking; loss of material caused by general, pitting, and crevice corrosion, or wear (BWR)	Chapter XI.M3, "Reactor Head Closure Stud Bolting"	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
High-strength low alloy steel closure head stud assembly exposed to air with potential for reactor coolant leakage (3.1.1-92)	Cracking caused by stress corrosion cracking; loss of material caused by general, pitting, and crevice corrosion, or wear (PWR)	Chapter XI.M3, "Reactor Head Closure Stud Bolting"	No	Reactor Head Closure Stud Bolting	Consistent with the GALL Report
Copper-alloy >15% Zn or > 8% Al piping, piping components, and piping elements exposed to closed cycle cooling water (3.1.1-93)	Loss of material caused by selective leaching	Chapter XI.M33, "Selective Leaching "	No	Not applicable	Not applicable to Callaway (see SER Section 3.1.2.1.1)
Stainless steel and nickel alloy vessel shell attachment welds exposed to reactor coolant (3.1.1-94)	Cracking caused by stress corrosion cracking, intergranular stress corrosion cracking	Chapter XI.M4, "BWR Vessel ID Attachment Welds," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Steel (with or without stainless steel cladding) feedwater nozzles exposed to reactor coolant (3.1.1-95)	Cracking caused by cyclic loading	Chapter XI.M5, "BWR Feedwater Nozzle"	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Steel (with or without stainless steel cladding) control rod drive return line nozzles exposed to reactor coolant (3.1.1-96)	Cracking caused by cyclic loading	Chapter XI.M6, "BWR Control Rod Drive Return Line Nozzle"	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel alloy piping, piping components, and piping elements greater than or equal to 4 NPS; nozzle safe ends and associated welds (3.1.1-97)	Cracking caused by stress corrosion cracking, intergranular stress corrosion cracking	Chapter XI.M7, "BWR Stress Corrosion Cracking," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel or nickel alloy penetrations: instrumentation and standby liquid control exposed to reactor coolant (3.1.1-98)	Cracking caused by stress corrosion cracking, intergranular stress corrosion cracking, cyclic loading	Chapter XI.M8, "BWR Penetrations," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Cast austenitic stainless steel; PH martensitic stainless steel; martensitic stainless steel; X-750 alloy reactor internal components exposed to reactor coolant and neutron flux (3.1.1-99)	Loss of fracture toughness caused by thermal aging and neutron irradiation embrittlement	Chapter XI.M9, "BWR Vessel Internals"	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel RVIs components (jet pump wedge surface) exposed to reactor coolant (3.1.1-100)	Loss of material caused by wear	Chapter XI.M9, "BWR Vessel Internals"	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel steam dryers exposed to reactor coolant (3.1.1-101)	Cracking caused by flow-induced vibration	Chapter XI.M9, "BWR Vessel Internals" for steam dryer	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel fuel supports and control rod drive assemblies control rod drive housing exposed to reactor coolant (3.1.1-102)	Cracking caused by stress corrosion cracking, intergranular stress corrosion cracking	Chapter XI.M9, "BWR Vessel Internals," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel and nickel alloy reactor internal components exposed to reactor coolant and neutron flux (3.1.1-103)	Cracking caused by stress corrosion cracking, intergranular stress corrosion cracking, irradiation-assisted stress corrosion cracking	Chapter XI.M9, "BWR Vessel Internals," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
X-750 alloy RVI components exposed to reactor coolant and neutron flux (3.1.1-104)	Cracking caused by intergranular stress corrosion cracking	Chapter XI.M9, "BWR Vessel Internals" for core plate, and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Steel piping, piping components, and piping element exposed to concrete (3.1.1-105)	None	None, provided 1) attributes of the concrete are consistent with ACI 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG-1557, and 2) plant OE indicates no degradation of the concrete	No, if conditions are met.	Not applicable	Not applicable to Callaway (see SER Section 3.1.2.1.1)
Nickel alloy piping, piping components, and piping element exposed to air – indoor, uncontrolled, or air with borated water leakage (3.1.1-106)	None	None	NA	None	Consistent with the GALL Report
Stainless steel piping, piping components, and piping element exposed to gas, concrete, air with borated water leakage, air – indoors, uncontrolled (3.1.1-107)	None	None	NA	None	Consistent with the GALL Report
(Not used) (3.1.1-108)	(Not used)	(Not used)	(Not used)	(Not used)	(Not used)
(Not used) (3.1.1-109)	(Not used)	(Not used)	(Not used)	(Not used)	(Not used)
Any material piping, piping components and piping elements exposed to reactor coolant (3.1.1-110)	Wall thinning due to erosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)

3.1.2.1 AMR Results Consistent with the GALL Report

LRA Section 3.1.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the reactor vessel, RVIs, and RCS components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
- Bolting Integrity
- Boric Acid Corrosion
- Closed Treated Water Systems
- Cracking of Nickel-Alloy Components and Loss of Material due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components
- External Surfaces Monitoring of Mechanical Components
- Flow-Accelerated Corrosion
- Flux Thimble Tube Inspection
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Lubricating Oil Analysis
- One-Time Inspection
- One-Time Inspection of ASME Code Class 1 Small-Bore Piping
- PWR Vessel Internals
- Reactor Head Closure Stud Bolting
- Reactor Vessel Surveillance
- Steam Generator
- Water Chemistry

LRA Tables 3.1.2-1 through 3.1.2-4 summarize the results of AMRs for the reactor vessel, RVIs, and RCS 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 if the plant-specific components in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR item describing how the information in the tables aligns with the information in the GALL Report. The staff reviewed those AMRs with notes A–E, which indicate how the AMR was consistent with the GALL Report.

Note A indicates that the AMR item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. The staff reviewed these AMR 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 AMR items to confirm consistency with the GALL Report and ensure that the applicant 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 AMR 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 AMR 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 identified the appropriate GALL Report AMRs. The staff's evaluation is discussed below.

3.1.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.1-1, items 3.1.1-11, 3.1.1-29, 3.1.1-41, 3.1.1-43, 3.1.1-79, 3.1.1-84, 3.1.1-85, 3.1.1-91, 3.1.1-94 through 3.1.1-104, and 3.1.1-110, 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 that these items are not applicable to Callaway, which is a PWR.

For LRA Table 3.1-1, items 3.1.1-34, 3.1.1-44, 3.1.1-51, 3.1.1-52, 3.1.1-55, 3.1.1-56, 3.1.1-58, 3.1.1-68, 3.1.1-73, 3.1.1-75, 3.1.1-82, 3.1.1-86, and 3.1.1-93, the applicant claimed that the corresponding items in the GALL Report are not applicable because the component, material, and environment combination described in the SRP-LR does not exist for in-scope SCs at Callaway. The staff reviewed the LRA and FSAR and confirmed that the applicant's LRA does not have any AMR results applicable for these items.

For LRA Table 3.1-1 items discussed below, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable; however, the staff non-applicability verification of these items required the review of sources beyond the LRA and FSAR, and/or the issuance of RAIs.

LRA Table 3.1-1, item 3.1.1-50 addresses CASS Class 1 piping, piping component, and piping elements and control rod drive pressure housings exposed to reactor coolant greater than 250 °C (482 °F). SRP-LR Table 3.1-1, item 3.1.1-50 recommends GALL AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)" to manage loss of fracture toughness due to thermal aging embrittlement of these components. For LRA item 3.1.1-50, the applicant stated that portions of the Callaway reactor coolant loops are constructed of CASS and that the straight piping pieces were centrifugally cast and the fittings were statically cast. The applicant also stated that thermal aging of Callaway CASS reactor coolant piping components and fittings is not a concern because the molybdenum and ferrite values for these piping pieces and fittings are below the thermal aging significance threshold.

In its review, the staff noted that Callaway FSAR Table 5.2-2 indicates that the reactor coolant pipe is made of centrifugal-cast SA-351, Grade CF8A and the reactor coolant fittings and branch nozzles are made of SA-351, Grade CF8A (cast stainless steel) and SA-182 (Code Case 1423-2), Grade 316N (non-cast stainless steel). The material information regarding CASS RCS components in the LRA and FSAR is summarized as follows.

- reactor coolant pipe: centrifugal-cast low-molybdenum CASS (SA-351, Grade CF8A)
- reactor coolant fittings: static-cast low-molybdenum CASS (SA-351, Grade CF8A)
- reactor coolant branch nozzles: low-molybdenum CASS (SA-351, Grade CF8A)

In comparison, GALL Report AMP XI.M12 states that for low-molybdenum content steels (SA-351 Grades CF3, CF3A, CF8, CF8A or other steels with molybdenum not exceeding 0.5 weight percent), only static-cast steels with ferrite greater than 20 percent are potentially susceptible to thermal aging embrittlement. GALL Report AMP XI.M12 also indicates that in the susceptibility screening method, ferrite content is calculated by using the Hull's equivalent factor (described in NUREG/CR-4513, Revision 1, "Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems," issued May 1994), or a staff-approved method for calculating delta ferrite in CASS materials.

In its review, the staff finds that the reactor coolant piping, which is fabricated from low-molybdenum centrifugal-cast stainless steel, is not susceptible to thermal aging embrittlement, as described in the GALL Report. However, the staff needed to confirm that the applicant appropriately screened the susceptibility of other CASS components, consistent with the GALL Report, because the LRA does not clearly indicate that the applicant's screening methodology is consistent with NUREG/CR-4513, Revision 1, as referenced in the GALL Report AMP XI.M12. In addition, the LRA does not clearly indicate whether the reactor coolant branch nozzles are made of static-cast material or centrifugal-cast material. Furthermore, the LRA does not provide the ferrite contents of the CASS fittings and branch nozzles.

By letter dated August 16, 2012, the staff issued RAI 3.1.1.50-1 requesting that the applicant clarify whether the reactor coolant branch nozzles are made of static-cast CF8A material or centrifugal-cast CF8A material. The staff also requested that the applicant provide the bounding-case chemical composition of the reactor coolant fittings and branch nozzles that was used to estimate the highest ferrite content of these CASS components. In addition, the staff requested that the applicant provide the calculated ferrite content in order to confirm that these

CASS components are not susceptible to thermal aging embrittlement. The staff further requested that as part of the response, the applicant clarify whether the applicant's screening methodology is consistent with the guidance of NUREG/CR-4513, Revision 1, which uses the Hull's equivalent factor as referenced in the GALL Report.

In its response dated September 20, 2012, the applicant stated that the CASS reactor coolant branch nozzles are made of static-cast CF8A material. The applicant provided the bounding-case chemical compositions that estimate the highest ferrite contents of the reactor coolant fittings and branch nozzles. The applicant also stated that the calculated ferrite contents are 19.65 percent and 18.69 percent for heat Nos. 3-3325 and 3-3447, respectively and that these values are below the 20 percent threshold value for static-cast CF8A material. The applicant further stated that the above ferrite content values were calculated using Hull's equivalent factors in NUREG/CR-4513, Revision 1.

In its review of the applicant's response, the staff confirmed that the bounding-case ferrite contents in terms of Hull's equivalent factors are 19.65 percent and 18.70 percent for the fittings and branch nozzles, respectively. These ferrite contents do not exceed the susceptibility threshold of 20 percent for static-cast low-molybdenum CASS materials, consistent with the applicant's determination. The staff finds the applicant's response acceptable because the applicant confirmed that its calculations for the ferrite contents, using the alloy compositions are consistent with the guidance of CR/NUREG-4513, Revision 1, which is referenced in the GALL Report. Furthermore, the estimated ferrite contents indicate that the CASS materials for Class 1 piping fittings and branch nozzles are not susceptible to thermal aging embrittlement. The staff's concern described in RAI 3.1.1.50-1 is resolved.

In its review, the staff noted that Callaway FSAR, Table 5.2-2 indicates that the control rod drive latch housings are made of SA-182, Grade F304 (non-cast stainless steel) or SA-351, Grade CF8 (cast stainless steel). Given the information regarding the control rod drive latch housing materials in the FSAR, the staff needed to confirm whether SA-351, Grade CF8 (cast stainless steel) has been used for the control rod drive latch housings. If the CASS material has been used for the CRD latch housings, additional information would be necessary regarding the applicant's material screening method for thermal aging embrittlement of the CASS material.

By letter dated September 12, 2012, the staff issued RAI 3.1.1.50-2 requesting that the applicant clarify whether SA-351, Grade CF8, or SA-182, Grade F304, has been used for the control rod drive latch housings. In its response dated October 15, 2012, the applicant stated that the control rod drive latch housings and travel housings are made of forged Type 304 stainless steel (non-cast stainless steel). The staff finds that the applicant's response acceptable because these housings are made of non-cast Type 304 stainless steel so that they are not susceptible to thermal aging embrittlement. The staff's concern described in RAI 3.1.1.50-2 is resolved

LRA Table 3.1.1, item 3.1.1-50 addresses CASS Class 1 piping, piping component, and piping elements and control rod drive pressure housings exposed to reactor coolant greater than 250 °C (482 °F). The GALL Report recommends GALL AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)" to manage loss of fracture toughness due to thermal aging embrittlement for this component group. The applicant stated that this item is not applicable because molybdenum and ferrite values for these piping components and fittings are below the thermal aging significance threshold. As described above, the staff evaluated the applicant's claim and RAI responses and finds it acceptable because the casting methods and molybdenum and ferrite contents of the CASS components confirm that these

components are not susceptible to thermal aging embrittlement, consistent with the GALL Report.

LRA Table 3.1-1, item 3.1.1-63 addresses steel or stainless steel closure bolting exposed to air with reactor coolant leakage. The GALL Report recommends GALL Report AMP XI.M18, "Bolting Integrity" to manage loss of material caused by general (steel only), pitting, and crevice corrosion or wear for this component group. The applicant stated that this item is not applicable because the item applies only to BWR plants. The staff lacks sufficient information to evaluate the applicant's claim because although the SRP-LR states that item 3.1.1-63 is applicable to BWRs, the applicant has in-scope steel or stainless steel closure bolting exposed to borated water leakage. The staff noted that the applicant is managing these items for loss of preload and cracking, but not loss of material. The staff also noted that the applicant has in-scope steel and stainless steel closure bolting exposed to plant indoor air and atmosphere or weather environments that are being managed for loss of material. By letter dated August 16, 2012, the staff issued RAI 3.1.1.063-1 requesting that the applicant state the basis for why loss of material caused by general (steel only), pitting, and crevice corrosion or wear is not applicable to in-scope steel and stainless steel closure bolting exposed to air with reactor coolant leakage.

In its response dated September 20, 2012, the applicant stated that the GALL Report for stainless steel closure bolting exposed to air with borated water leakage or air with PWR reactor coolant leakage identifies only cracking caused by SCC and loss of preload as applicable aging effects. However, the applicant also stated that to account for the loss of material aging effect for those components, items have been added to LRA Tables 3.1.2-2, 3.2.2-1, 3.2.2-5, 3.3.2-2, 3.3.2-10, and 3.3.2-28 for stainless steel closure bolting with an environment of plant indoor air and an aging effect of loss of material in systems which previously included stainless steel closure bolting in an environment of borated water leakage.

The staff finds the applicant's response acceptable because the applicant will manage the stainless steel closure bolting for loss of material. The staff notes that although the applicant has not identified loss of material as an aging effect for stainless steel closure bolting exposed to air with reactor coolant leakage, the applicant has still accounted for the loss of material aging effect by adding additional items for the stainless steel closure bolting components. The staff's concern described in RAI 3.1.1.063-1 is resolved.

LRA Table 3.1-1, item 3.1.1-64 addresses steel closure bolting exposed to an air-indoor uncontrolled environment. The GALL Report recommends GALL Report AMP XI.M18, "Bolting Integrity" to manage loss of material caused by general, pitting, and crevice corrosion for this component group. The applicant stated that this item is not applicable because the steel closure bolting in the RCS is evaluated with the environment of air with borated water leakage. The staff evaluated the applicant's claim and finds it acceptable because (1) the component group is managed for the loss of material aging effect through SPR-LR Table 3.1-1, item 3.1.1-49, which recommends that steel RCPB external surfaces or closure bolting exposed to air with borated water leakage be managed by the Boric Acid Corrosion Program and (2) the air with borated water leakage environment is a more aggressive environment than air-indoor uncontrolled, and is therefore a more conservative environment to identify for aging management.

LRA Table 3.1-1, item 3.1.1-65 addresses stainless steel control rod drive head penetration flange bolting exposed to air with reactor coolant leakage. The GALL Report recommends GALL Report AMP XI.M18, "Bolting Integrity" to manage loss of material caused by wear for this component group. The applicant stated that this item is not applicable because Callaway has

stainless steel control rod drive head penetration flanges that are seal welded instead of bolted. The staff evaluated the applicant's claim and finds it acceptable because the staff reviewed the LRA and FSAR and confirmed that the applicant does not have any in-scope components that are applicable for this item.

3.1.2.1.2 Management of Aging Effects for PWR Vessel Internals – AMR Items in the Callaway LRA Not Tied to SRP-LR Further Evaluation Recommendations for PWR RVI Components

LRA Table 3.1-1 includes AMR items that are based on SRP-LR, Table 3.1-1 AMR item that are applicable to Westinghouse-designed RVI component commodity groups. These AMR items include the following LRA Table 3.1-1 AMR items that are based on the staff's further evaluation "acceptance criteria" recommendations for PWR RVI components in SRP-LR Section 3.1.2.2:

- item 3.1.1-3 on evaluation of cumulative fatigue damage in the RVI components that are defined as core support structure components, which is based on a comparison to the staff's recommended further evaluation "acceptance criteria" recommendations in SRP-LR Section 3.1.2.2.1 and the AMR criteria in SRP-LR Table 3.1-1, item No. 3
- item 3.1.1-23 on evaluation of cracking in inaccessible areas of the RVI components, which is based on a comparison to the staff's recommended further evaluation "acceptance criteria" recommendations in SRP-LR Section 3.1.2.2.9 and the AMR criteria in SRP-LR Table 3.1-1, item No. 23
- item 3.1.1-24 on evaluation of loss of material caused by wear, loss of fracture toughness, changes in dimension, loss of preload in inaccessible areas of the RVI components, which is based on a comparison to the staff's recommended further evaluation "acceptance criteria" recommendations in SRP-LR Section 3.1.2.2.10 and the AMR criteria in SRP-LR Table 3.1-1, item No. 24
- item 3.1.1-26 on management of cracking caused by fatigue, which is based on a comparison to the staff's recommended further evaluation "acceptance criteria" recommendations in SRP-LR Section 3.1.2.2.12 and the AMR criteria in SRP-LR Table 3.1-1, item No. 26
- item 3.1.1-27 on management of cracking caused by SCC and fatigue of CRGT pins, which is based on a comparison to the staff's recommended further evaluation "acceptance criteria" recommendations in SRP-LR Section 3.1.2.2.13 and the AMR criteria in SRP-LR Table 3.1-1, item No. 27
- AMR item 3.1.1-28 on management of loss of material caused by wear in CRGT pins, which is based on a comparison to the staff's recommended further evaluation "acceptance criteria" recommendations in SRP-LR Section 3.1.2.2.14 and the AMR criteria in SRP-LR Table 3.1-1, item No. 28

The staff evaluates these AMR items in SER Sections 3.1.2.2.1, 3.1.2.2.9, 3.1.2.2.10, 3.1.2.2.12, 3.1.2.2.13, and 3.1.2.2.14, respectively.

The remaining AMR items for the PWR RVI component commodity groups in LRA Table 3.1-1 include LRA items 3.1.1-32, 3.1.1-53, 3.1.1-59, and 3.1.1-87, each of which invokes specific Table 2 AMR items for PWR RVI components in LRA Table 3.1.2-1. The staff evaluates these Table 1 AMR items in the following SER Sections: (a) SER Section 3.1.2.1.3 for items 3.1.1-32, 3.1.1-53, and 3.1.1-59, as related to the assessment of cracking caused by SCC, irradiated-assisted stress corrosion cracking (IASCC), or fatigue; loss of material caused by

wear; loss of fracture toughness caused by neutron irradiation embrittlement, void swelling, or thermal aging; changes in dimension caused by distortion or void swelling; and loss of preload caused by stress relaxation or irradiation-assisted stress relaxation or creep in PWR RVI components; and (b) SER Section 3.1.2.1.4 for item 3.1.1-87, as related to the assessment of loss of material induced by a pitting or crevice corrosion mechanism.

The following clarifications need to be made for those RVI components listed in LRA Table 3.1.2-1 that will be managed using the applicant's PWR Vessel Internals Program and whose Table 2 AMR items are referenced to by either LRA Table 1 AMR items 3.1.1-53 or 3.1.1-59. The applicant's PWR Vessel Internals Program is identified and defined as a new program that is consistent with the program element criteria in GALL Report AMP XI.M16A, "PWR Vessel Internals." GALL Report AMP XI.M16A recommends management of cracking because of SCC, IASCC, or fatigue; loss of fracture toughness caused by neutron irradiation embrittlement, void swelling or thermal aging; changes in dimension caused by distortion or void swelling; loss of material caused by wear; or for RVI mechanical connections (such as bolted, spring loaded, pinned, keyed, or other types of fastened connections), loss of preload caused by stress relaxation or irradiation-assisted creep using the sampling-based condition monitoring basis that is defined in the EPRI Report No. 1022863, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A)." The MRP-227-A report was approved in the staff's revised safety evaluation (SE, Revision 1) on the report's methodology dated December 16, 2011. Thus, the applicant's PWR Vessel Internals Program is a sampling-based condition monitoring program that is based on the sampling-based augmented inspection methodology in the MRP-227-A report and is in conformance with the staff's criteria for sampling-based condition monitoring programs in Appendix A.1, "Aging Management Review – Generic (Branch Technical Position RLSB-1)," of the SRP-LR. In the MRP-227-A report, the EPRI MRP established and implemented specific "Failure Modes, Effects, and Criticality Analyses [FMECAs]" and "Functionality Analyses" for all of RVI components that could be included within the scope of a Westinghouse-defined nuclear power plant facility and used these analyses to break down the population of RVI components into the following categories of components (i.e., the component samples):

(a) "Existing Program" – RVI components that would be subject to condition monitoring (inspection) because they were within specific existing inspection programs at the facilities. Examples are the ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD Program for RVI components defined as ASME Section XI, Examination Category B-N-3 RVI core support structure components, or for RVI flux thimble tubes, a Westinghouse-design applicant's NRC Bulletin 88-09-based Flux Thimble Tube Inspection Program.

(b) "Primary Category" – RVI components that would be inspected using the EPRI MRP's recommended augmented inspection bases in the MRP-227-A report. For Westinghouse-designed RVI components, the EPRI MRP's augmented inspection bases for "Primary Category" components are given in Table 4-3 of the MRP-227-A report and the acceptance criteria for the augmented inspections of these components are given in Table 5-3 of the MRP-227-A report.

(c) "Expansion Category" – RVI components that are linked to specific "Primary Category" components and for whom the augmented inspections would be expanded to if relevant evidence of aging was detected in the "Primary Category" RVI component for a specific "Primary Category" component – "Expansion Category" component pair combination.

(d) "No Additional Measures" – components, which constitute the remaining components in RVI component population. Under the EPRI MRP defined methodology, these

components would not be inspected because either there weren't any aging effect mechanisms that were applicable to the components or, if there were applicable aging effects and mechanisms, there would not be any consequence from a failure of the RVI component by the aging effect or effects that were applicable to the component. However, the EPRI MRP clarifies that, even though a "No Additional Measures" component is not inspected in accordance with MRP-227-A methodology basis, the component will need to be inspected under the applicant's ASME Section XI Inservice Inspection Program if the RVI component is defined in the CLB as an ASME Code Section XI, Examination Category B-N-3 core support structure component.

In the NRC's SE, Revision 1 on the MRP-227-A methodology, the staff identified a number of license renewal aging management areas that would need to be addressed on a plant-specific assessment by Westinghouse-design PWR license renewal applicants. The staff identified these topical areas as applicable A/LAIs on use of the MRP-227-A methodology. In the SE, Revision 1 on the MRP-227-A report, the staff stated that PWR license renewal applicants should provide in their LRAs responses to both the generic A/LAIs on the MRP-227-A methodology and the NSSS-specific A/LAIs that were applicable to the design of their facilities. The staff has reflected this need in RIS 2011-07, "License Renewal Submittal Information for Pressurized Water Reactor Internals Aging Management," dated July 21, 2011. These A/LAI responses are important because the A/LAI responses will be used as part of the applicant's integrated plant assessment for determining whether the applicant would need to establish and implement any plant-specific enhancements of its RVI Management program beyond the generic aspects of the program that would be implemented in accordance with the MRP-227-A methodology.

The staff noted that the LRA, when submitted to the staff for review, did not include any of the applicant's responses to the A/LAIs on MRP-227-A methodology. Therefore, by letter dated September 25, 2012, the staff issued RAI B2.1.6-4 requesting that the applicant provide its basis for omitting responses to the applicable A/LAIs on MRP-227-A methodology that are determined to be applicable to Westinghouse-designed RVI components at the Callaway Plant. Alternatively, the staff informed the applicant that it could amend its LRA to include the appropriate responses to those A/LAIs that have been issued on the MRP-227-A report and are applicable to the design of the Westinghouse-designed RVI components at the Callaway Plant.

Consistent with the "scope of program" element in GALL Report AMP XI.M16A, "PWR Vessel Internals," the applicant's response bases to the A/LAIs on MRP-227-A report are recommended to be included in the "scope of program" element of the applicant PWR Vessel Internals Program. The applicant responded to RAI B2.1.6-4 in a letter dated October 24, 2012. The staff's evaluation of the applicant's response to RAI B2.1.6-4 is documented in SER Section 3.0.3.1.5, which is the SER section that provides the staff's evaluation of the applicant's PWR Vessel Internals Program and the responses to these A/LAIs.

The staff also noted that the Table 2 AMR item component nomenclatures in LRA Table 3.1.2-1 for a number of Callaway RVI components did not entirely match the generic nomenclatures for these components in either Table IV.B2 of the GALL Report or in the EPRI MRP's recommended generic methodology for Westinghouse-designed RVI components, as given in MRP-227-A. Therefore, by letter dated September 12, 2012, the staff issued RAI 3.1.2.1-1 requesting additional clarifications on the component nomenclatures that were used for various RVI components associated AMR items in LRA Table 3.1.2-1. In its response dated October 15, 2012, the applicant provided the following additional information to address the staff's concerns described in Requests (a) through (k) of RAI 3.1.2.1-1:

RAI 3.1.2.1-1, Part (a): For the two AMR items associated with the RVI baffle-former assembly on LRA page 3.1-69, the staff requested the applicant to clarify which specific baffle-former assembly components are within the scope of the AMR items. In response to this part of the RAI, the applicant clarified that the components in the AMRs for the RVI baffle-former assembly include the baffle plates and the former plates. The staff finds that the applicant's clarification demonstrates that components in the AMR items are in conformance with the basis in MRP-227-A for inspecting the baffle plates and former plates in Westinghouse-design core barrel assemblies and covers management of both loss of material because of pitting and crevice corrosion, as recommended in GALL Report AMP IV.B2.RP-270, and changes in dimension, as recommended in GALL Report AMR item IV.B2.RP-24. Thus, the staff finds that these AMR items are acceptable because they demonstrate consistency the GALL Report AMR items IV.B2.RP-24 and IV.B2.RP-270 and with the inspection bases for these components in the MRP-227-A report. RAI 3.1.2.1-1, Part (a), is resolved.

RAI 3.1.2.1-1, Part (b): For the four AMRs associated with the RVI baffle-former assembly bolting at the bottom of LRA page 3.1-69 and top of page 3.1-70, the staff requested the applicant to clarify whether the AMR items are referring to baffle-to-former bolts or to otherwise identify which specific bolts are within the scope of the AMR items. In response to this part of the RAI, the applicant clarified that these AMR items are referring to the baffle-to-former bolts. The staff notes that the applicant's clarification demonstrates that the components in these AMR items are in conformance with the basis in MRP-227-A for inspecting Westinghouse-design baffle-to-former bolts as MRP-227-A "Primary Category" components and that the AMR items are in conformance with the following AMR items for Westinghouse-design baffle-to-former bolts in the GALL Report: (a) AMR item IV.B2.RP-24 for managing loss of material caused by pitting and crevice corrosion; (b) AMR item IV.B2.RP-271 for managing cracking; (c) AMR item IV.B2.RP-272 for managing loss of fracture toughness, changes in dimension, and loss of preload; and (d) AMR item IV.B2.RP-303 for managing cumulative fatigue damage. Thus, the staff finds that these LRA AMR items are acceptable because the applicant has demonstrated consistency with the AMR item bases for the components in the GALL Report and with the inspection bases for these components in the MRP-227-A report. RAI 3.1.2.1-1, Part (b), is resolved.

RAI 3.1.2.1-1, Part (c): For the four AMR items associated with the RVI CRGT assembly on LRA page 3.1-71, the staff requested the applicant to clarify which of the specific CRGT assembly components are within the scope of the AMR items. In response to this part of the RAI, the applicant clarified that these AMR items are referring to the lower flange welds and the adjacent base metal of the CRGT assemblies. The applicant also clarified that the AMR items for the CRGT bolts, guide plates (cards) and support pins (split pins) are evaluated in separate AMR items in LRA Table 3.1.2-1. The staff notes that the applicant's clarification demonstrates that the components in these AMR items are in conformance with the basis in MRP-227-A for inspecting Westinghouse-design CRGT lower flange welds as MRP-227-A "Primary Category" components and with the following AMR items for Westinghouse-design CRGT lower flange welds in the GALL Report: (a) AMR item IV.B2.RP-24 for managing loss of material caused by pitting and crevice corrosion, (b) AMR item IV.B2.RP-298 for managing cracking, (c) AMR item IV.B2.RP-297 for managing loss of fracture toughness, and (d) AMR item IV.B2.RP-303 for managing cumulative fatigue damage. Thus, the staff finds that these LRA AMR items are acceptable because the applicant has demonstrated consistency with the AMR item bases for the components in the GALL Report and with the "Primary Category" inspection bases for these components in the MRP-227-A report. RAI 3.1.2.1-1, Part (c), is resolved.

RAI 3.1.2.1-1, Part (d): For the two AMR items associated with RVI CRGT bolts listed on LRA page 3.1-72, the staff requested the applicant to identify which specific bolts are within the scope of the AMR items. In response to this request, the applicant stated that, consistent with the basis in FSAR Section 3.9(N).5, the CRGTs are fastened to the top support plate, but are not included in the scope of the MRP-227-A report. Therefore, the applicant clarified that the aging evaluation and aging management basis for these CRGT bolts is based on consistency with GALL Report AMR item IV.B2.RP-24 for managing loss of material in the components caused by pitting and crevice corrosion and with GALL Report AMR item IV.B2.RP-382 for managing cracking and loss of material caused by wear in the components, as indicated in the amended LRA AMR item provided in its response. The staff finds that these LRA AMR items are acceptable because the applicant has demonstrated consistency with the AMR item bases for the components in the GALL Report and will inspect these components in accordance with ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, even though the components are defined the MRP-227-A report as “No Additional Measures” components. RAI 3.1.2.1-1, Part (d), is resolved.

RAI 3.1.2.1-1, Part (e): For the three AMR items associated with the RVI core barrel or core barrel assembly on LRA page 3.1-73, the staff requested the applicant to identify which of the specific core barrel assembly components are within the scope of the AMR items. In response to this request, the applicant stated that the core barrel cylinder welds, flange and flange welds, and outlet nozzle and nozzle welds are addressed in separate AMR items in LRA Table 3.1.2-1. The applicant clarified that the subject AMR items of this RAI request are referring to the balance of the core barrel assembly, which is not specifically addressed in MRP-227-A report. The applicant also stated that the aging evaluation and aging management basis for the balance of the core barrel assembly is based on GALL Report items IV.B2.RP-24 and IV.B2.RP-382. The applicant further stated that the AMR item for managing cumulative fatigue damage in the core barrel assembly applies to the whole assembly and its subcomponents and credits the metal fatigue TLAA as the basis for managing cumulative fatigue damage of these components. The staff finds that these LRA AMR items are acceptable because the applicant has demonstrated consistency of the AMR items for the remainder of the core barrel assembly with the AMR item bases for the core barrel assembly in the GALL Report and will inspect these components in accordance with ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. RAI 3.1.2.1-1, Part (e), is resolved.

RAI 3.1.2.1-1, Part (f): For the three AMR associated with the RVI core barrel assembly former bolting on LRA pages 3.1-73 and 3.1-74, the staff requested the applicant to clarify whether the AMR items are referring to core barrel-to-former bolts, as defined in MRP-227-A. Otherwise, the staff requested the applicant to identify which specific bolts are within the scope of the AMR items. In response to this request, the applicant stated that AMR items are presented in the LRA as “RVI core barrel assembly-former bolting,” consistent with MRP-227-A, Tables 3-3 and 4-5, but are referring to core barrel assembly barrel-to-former bolts, as described in GALL Report AMR items IV.B2.RP-273 and IV.B2.RP-274. The staff notes that the applicant’s clarification demonstrates that the AMR basis for these components is in conformance with the basis in MRP-227-A for inspecting Westinghouse-design barrel-to-former bolts as EPRI MRP-defined “Expansion Category” components and the following AMR items for Westinghouse-design barrel-to-former bolts in the GALL Report: (a) AMR item IV.B2.RP-24 for managing loss of material caused by pitting and crevice corrosion; (b) AMR item IV.B2.RP-273 for managing cracking; and (c) AMR item IV.B2.RP-274 for managing loss of fracture toughness, loss of preload, and changes in dimension. Thus, the staff finds that these AMR items in the LRA are acceptable because the applicant has demonstrated consistency with the

AMR item bases for the components in the GALL Report and with the inspection bases for these components in the MRP-227-A report. RAI 3.1.2.1-1, Part (f), is resolved.

RAI 3.1.2.1-1, Part (g): For the two AMR items associated with the RVI head/vessel alignment pins on LRA page 3.1-75, the staff requested the applicant to clarify whether these components correspond to the upper core plate alignment pins in MRP-227-A (i.e., alignment and interfacing components in MRP-227-A Table 3-3). Otherwise, the staff requested the applicant to clarify where the pins are located and which MRP-227-A defined RVI assembly corresponds to the location of these pins. The applicant responded that the RVI head/vessel alignment pins are shown in FSAR Figure 3.9(N)-3 as item No. 31. The applicant clarified that the upper core plate alignment pins referred to in the MRP-227-A report are listed in LRA Table 3.1.2-1 as "RVI upper core plate guide pins" (to avoid confusion with fuel alignment pins that are attached to the bottom of the upper core plate) and are listed in FSAR Figure 3.9(N)-3 as item No. 19. The applicant stated that the RVI head/vessel alignment pins are not included in the scope of inspections defined in the MRP-227-A report, as the components were screened as Category “A” “No Additional Measures” component in MRP-191, Table 7-2. The applicant also stated that the aging evaluation and aging management basis is therefore based on conformance with GALL Report AMR items IV.B2.RP-24 and IV.B2.RP-382. The staff finds that these LRA AMR items are acceptable because the applicant has demonstrated consistency of the AMR items for the RVI head/vessel pins with the AMR item bases for the core barrel assembly in the GALL Report and will inspect these components in accordance with ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. RAI 3.1.2.1-1, Part (g), is resolved.

RAI 3.1.2.1-1, Part (h): For the two AMR items associated with the RVI incore instrumentation (ICI) core support structure bolting on LRA page 3.1-76; the staff requested the applicant to clarify where the bolts are located and which MRP-227-A defined RVI assembly corresponds to the location of these bolts. The applicant responded that the RVI ICI core support structure bolting referred to in the AMR items represent the lower core ICI support BMI column bolts. The applicant stated that the lower core BMI column bolts are shown in FSAR Figure 3.9(N)-3 as item No. 27. The applicant also stated that these bolts are not included in the scope of the MRP-227-A methodology, as they were screened out as Category “A” “No Additional Measures” components in MRP-191, Table 7-2 and that the aging evaluation and aging management basis is therefore based on conformance with GALL Report AMR items IV.B2.RP-24 and IV.B2.RP-382. The staff finds that these LRA AMR items are acceptable because the applicant has demonstrated consistency of the AMR items for the lower core ICI support BMI column bolts with the corresponding AMR item bases in the GALL Report and will inspect these components in accordance with ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. RAI 3.1.2.1-1, Part (h), is resolved.

RAI 3.1.2.1-1, Part (i): For the three AMR associated with the RVI ICI support structure-BMI instrument columns on LRA pages 3.1-76 and 3.1-77, the staff requested the applicant to clarify whether the AMR items are referring to BMI column bodies. Otherwise, the staff requested the applicant to identify which specific BMI column components are within the scope of the AMR items. In its response the applicant confirmed that the AMR items are based on FSAR Figure 3.9(N)-8 and are referring to BMI column bodies in the BMI system, as described in MRP-227-A, Table 4-6. The staff confirmed that, under the MRP-227-A methodology basis, the applicant would inspect these components as “Expansion Category” components for the PWR Vessel Internals based on the results of the “Primary Category” inspections that would be performed on the CRGT lower flange under this AMP. The staff also confirmed that the AMR items for the BMI column bodies were in conformance with the following GALL Report AMR items: (a) AMR

item IV.B2.RP-24 for managing loss of material caused by pitting and crevice corrosion; (b) GALL Report AMR item IV.B2.RP-292 for managing loss of fracture toughness; and (c) GALL Report AMR item IV.B2.RP-293 for managing cracking. Thus, the staff finds that these LRA AMR items are acceptable because the applicant has demonstrated consistency with the AMR item bases for the components in the GALL Report and with the inspection bases for these components in the MRP-227-A report. RAI 3.1.2.1-1, Part (i), is resolved.

RAI 3.1.2.1-1, Part (j): For two AMR items associated with the RVI lower core support-energy absorber assembly on LRA page 3.1-81, the staff requested the applicant to identify which energy absorber assembly components are within the scope of the AMR items and to clarify which MRP-227-A defined assembly corresponds to the location of the components. The applicant responded that the function of the energy absorber assembly is described in FSAR Section 3.9(N).5, and that assuming a downward vertical displacement, the potential energy of the system is absorbed mostly by the strain energy of the energy absorbing devices. The applicant stated that the details of the energy absorber assembly are shown in FSAR Figure 3.9(N)-8, but the components of the energy absorber assembly were not included in the scope of MRP-227-A as they were screened as Category "A" "No Additional Measures" components in MRP-191, Table 7-2. The staff finds that the applicant's aging evaluation and aging management basis for the energy absorber assembly is therefore based on conformance with GALL Report AMR items IV.B2.RP-24 and IV.B2.RP-382. The staff also finds that these LRA AMR items are acceptable because the applicant has demonstrated consistency of the AMR items for the energy absorber assembly with the corresponding AMR item bases in the GALL Report and will inspect these components in accordance with ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. RAI 3.1.2.1-1, Part (j), is resolved.

RAI 3.1.2.1-1, Part (k): For three AMRs associated with the RVI upper core plate guide pins on LRA pages 3.1-82 and 3.1-83, the staff requested the applicant to clarify whether the AMR items correspond to the upper core plate alignment pins listed as "Alignment and Interfacing" "Existing Program" components in MRP-227-A Table 3-3. Otherwise, the staff requested the applicant to clarify where these pins are located and which MRP-227-A defined RVI assembly corresponds to the location of the pins. The applicant responded that the AMR items for the RVI upper core plate guide pins correspond to the upper core plate alignment pins described in MRP-227-A, Tables 3-3 and 4-9 and that they are listed in LRA Table 3.1.2-1 as RVI upper core plate guide pins, consistent with the description in FSAR Figure 3.9(N)-8, to avoid confusion with fuel alignment pins that are attached to the bottom of the upper core plate. The applicant stated that the fuel alignment pins are evaluated as integral parts of the upper core plate. The staff confirmed that, under the MRP-227-A methodology basis, the applicant would inspect these components as ASME Code Section XI, "Existing Program," components under the PWR Vessel Internals Program. The staff also confirmed that the AMR items for the RVI upper core plate guide pins were in conformance with the following GALL Report AMR items for these components: (a) AMR item IV.B2.RP-24 for managing loss of material caused by pitting and crevice corrosion; (b) GALL Report AMR item IV.B2.RP-292 for managing loss of material due to wear; and (c) GALL Report AMR item IV.B2.RP-301 for managing cracking. Thus, the staff finds that these LRA AMR items are acceptable because the applicant has demonstrated consistency with the AMR item bases for the components in the GALL Report and with the inspection bases for these components in the MRP-227-A report. RAI 3.1.2.1-1, Part (k), is resolved.

Based on its review of the applicant's responses to RAI 3.1.2.1-1, Parts (a) through (k), as discussed above, the staff's concerns described in RAI 3.1.2.1-1 are resolved.

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

3.1.2.1.3 Cracking due to Stress Corrosion Cracking, Irradiation Assisted Stress Corrosion Cracking, or Fatigue; Loss of Material due to Wear; Loss of Fracture Toughness due to Neutron Irradiation Embrittlement, Void Swelling, or Thermal Aging; Changes in Dimension due to Distortion or Void Swelling; and Loss of Preload due to Stress Relaxation or Irradiation-Assisted Stress Relaxation or Creep

In LRA Table 3.1.2-1, the applicant aligns its AMR items on cracking of specific RVI components to either the its basis for managing this aging effect in LRA Table 3.1-1, item 3.1.1-32 or in LRA Table 3.1-1, item 3.1.1-53. In LRA Table 3.1.2-1, the applicant aligns its AMR items on loss of material due to wear of specific RVI components to either the applicant's basis for managing this aging effect in LRA Table 3.1-1, item 3.1.1-32 or in LRA Table 3.1-1, item 3.1.1-59.

In LRA Table 3.1.2-1, the applicant aligns its AMR items on loss of fracture toughness due to neutron irradiation embrittlement, void swelling, or thermal aging; changes in dimension because of distortion or void swelling; and loss of preload caused by stress relaxation or irradiation-assisted stress relaxation or creep of specific RVI components to its basis for managing these aging effects in LRA Table 3.1-1, item 3.1.1-059.

LRA Table 3.1-1, item 3.1.1-32 addresses the Callaway RVI components made from either stainless steel or nickel alloy materials that are exposed to reactor coolant and neutron flux environment, which will be managed for the aging effect and mechanism combinations of cracking due to SCC, IASCC, or fatigue (cyclical loading) and loss of material caused by wear.

The staff noted that Section 4.4.3 and Table 4-9 in the MRP-227-A report provide a list of those "Existing Program" components that are identified as ASME Code Section XI core support structure components. The MRP-227-A states that these components are examined per ASME Code Section XI Table IWB-2510, "Examination Category B-N-3 requirements." During the audit, the staff noted that the applicant's program basis documents did not identify which RVI components were ASME Code Section XI, Examination Category B-N-3 RVI, components for the CLB, or whether the list of ASME Code Section XI, Examination Category B-N-3, components at Callaway include RVI core support structure components not accounted in Table 4-9 of the MRP-227-A report. The staff also noted that the applicant did not clarify whether the method of performing the VT-3 visual examination in accordance with applicable ASME Code Section XI examination category requirements would actually achieve coverage of those RVI components that were designated as ASME Code Section XI, Examination Category B-N-3, components at Callaway.

By letter dated July 18, 2012, the staff issued RAI B2.1.6-3. In Part (a) of the RAI the staff asked the applicant to identify all RVI component locations that are designated as ASME Code Section XI, Examination Category B-N-3, components at Callaway. In Part (b) of the RAI the staff asked the applicant to identify any ASME Code Section XI, Examination Category B-N-3, component locations and associated aging effects that are not assumed for and identified in Table 4-9 of the generic MRP-227-A methodology. In Part (c) of the RAI the staff asked the applicant to clarify and justify, based on previous ASME Code Section XI examinations of B-N-3 component surfaces, whether the implementation of VT-3 examinations of these component

surfaces would actually achieve coverage of those components locations that were defined as ASME Code Section XI, Examination Category B-N-3 component locations at Callaway.

By letter dated August 21, 2012, the applicant provided its response to RAI B2.1.6-3, Requests (a), (b), and (c). The staff's full evaluation of the applicant's response to RAI B2.1.6-3, Requests (a), (b), and (c) is documented in SER Section 3.0.3.1.5. The staff noted that the response to RAI B2.1.6-3, Requests (a), (b), and (c) confirms that the applicant will be crediting the inspection that will be performed in accordance with ASME Code Section XI, Examination Category B-N-3, requirements for all RVI components that are defined in the CLB as ASME Code Section XI, Examination Category B-N-3, core support structure components. The staff also noted, based on the applicant's response to RAI B2.1.6-3, Requests (a), (b), and (c), that the applicant will implement these requirements either through implementation of the PWR Vessel Internals Program's ASME Code Section Section XI "Existing Program" activities or through implementation of the applicable Examination Category B-N-3 requirements under its ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program.

For the AMR items in LRA Table 3.1.2-1 that are linked to LRA Table 3.1-1, item 3.1.1-32 and align to GALL Report AMR item IV.B2.RP-382 using the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program as the aging management basis, the applicant amended the LRA AMR items by letter dated October 24, 2012, to indicate that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, will be used to manage both cracking and loss of material caused by wear in the components. The scope of this aging management basis includes the following RVI components for which the ASME Code Section XI, Examination of Category B-N-3 visual VT-3 inspection requirements will be performed through implementation the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program instead of the "Existing Program" bases of the PWR Vessel Internals Program:

- CRGT bolting
- core barrel
- core barrel outlet nozzles
- RVI head and vessel alignment pins
- RVI hold-down spring
- RVI ICI structure exit thermocouple
- RVI irradiation specimen basket (i.e., the basket that contains the reactor vessel Charpy-impact test specimens that are required by 10 CFR Part 50, Appendix H, "Reactor Vessel Material Surveillance Program Requirements")
- RVI lower core support key, clevis inserts, and clevis insert bolting
- RVI lower core support energy absorber assembly
- top support plate, upper support column, and upper support column bolting in the RVI upper support

For these components, the applicant credits its ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program instead of the PWR Vessel Internal Program because: (a) the components are not inspected as part of MRP-227-A report basis, in that they

are defined as “No Additional Measures” under the report’s methodology; (b) the components are defined as ASME Code Section XI, Examination Category B-N-3 core support structure components for the part of the CLB that is used to comply with 10 CFR 50.55a requirements, and; (c) the VT-3 visual inspections that are invoked by regulations in 10 CFR 50.55a and by the ASME Code Section XI, Examination Category B-N-3 requirements are applicable to the components. The staff finds this basis acceptable because it is consistent with the GALL Report and because the applicant will be implementing the applicable ASME Code Section XI examinations of the components even though the components are defined as “No Additional Measures” components under the applicant’s PWR Vessel Internals Program and MRP-227-A conformance basis.

LRA Table 3.1-1, item 3.1.1-53 addresses RVI components made from either stainless steel or nickel alloy materials exposed to a reactor coolant and neutron flux environment, which will be managed for the aging effect and mechanism combinations of cracking due to SCC, IASCC, or fatigue (cyclical loading). LRA Table 3.1-1, item 3.1.1-59 addresses RVI components made from either stainless steel or nickel alloy materials exposed to reactor coolant and neutron flux environment, which will be managed for the aging effect and mechanism combinations of loss of material due to wear; loss of fracture toughness due to neutron irradiation embrittlement, void swelling, or thermal aging (applicable only to CASS, martensitic stainless steel materials, or precipitation hardened stainless steel materials); changes in dimension due to distortion or void swelling; or for fastened or bolted connections, loss of preload due to stress relaxation or irradiation-assisted creep.

For RVI component AMR items in LRA Table 3.1.2-1 that align either the LRA AMR item 3.1.1-53 or 3.1.1-59, the applicant credits the PWR Vessel Internals Program to manage the stainless steel or nickel alloy RVI components that are exposed to the reactor coolant and neutron flux environment and are susceptible to the aging effects. The GALL Report recommends GALL Report AMP XI.M16A, “PWR Vessel Internals,” to ensure that these aging effects are adequately managed. GALL Report AMP XI.M16A recommends management of these aging effects using the sampling-based condition monitoring basis that is defined in the MRP-227-A report.

The staff noted that the AMR items on cracking of specific RVI components in LRA Table 3.1.2-1 were consistent with AMR item No. 53 in the SRP-LR and that the AMR items on loss of material due to wear, loss of fracture toughness, loss of preload, or changes in dimension for specific RVI components in LRA Table 3.1.2-1 were consistent with AMR item No. 59 in the SRP-LR, with the exception of the AMR items discussed below for which the staff needed further clarification.

The staff noted that, in LRA Table 3.1.2-1, the applicant appropriately credited either its PWR Vessel Internals Program or the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program as the basis for managing loss of material in all RVI components that were susceptible to a wear-based mechanism, with the exception the CRGT support pins (split pins), core barrel flanges, or upper core plate. However, the staff noted that Table 3-3 of the MRP-227-A report identifies that loss of material due to wear is an applicable aging effect for these components. The staff’s evaluation of the applicant’s basis for managing loss of material due to wear in the CRGT split pins is documented in SER Section 3.1.2.2.14. The evaluation in SER Section 3.1.2.2.14 includes the staff’s evaluation of the applicant’s response to RAI 3.1.2.1-4, Part (a), which asked the applicant to provide justification for managing loss of material caused by wear in the CRGT split pins using only the Water Chemistry Program.

With respect to the evaluation of loss of material caused by wear in the upper core plate, the staff noted that the applicant had inadvertently identified the applicable non-cracking effect as loss of fracture toughness and not loss of material due to wear. In LRA Amendment No. 1, provided by letter dated April 25, 2012, the applicant appropriately corrected this oversight by amending the applicable AMR item to identify that the applicable non-cracking effect is loss of material (by wear) and by crediting the PWR Vessel Internals Program as the basis for monitoring and managing loss of material that might initiate in the core plate as a result of wear. The applicant also amended the AMR item for the upper core plate to identify that under the PWR Vessel Internals Program, the upper core plate is an "expansion category" component for the management of loss of material by wear. The PWR Vessel Internals Program would call for the upper core plate to be inspected for wear if relevant indications of wear are detected in the CRGT lower flange weld (which is the corresponding "primary category" component for the upper core plate). The staff found the amended AMR item on loss of material caused by wear in the upper core plate to be acceptable because it is in conformance with the staff-endorsed methodology in the MRP-227-A report.

For the core barrel flanges, the staff noted that the applicant had only credited the Water Chemistry Program to manage loss of material that might occur in the component. In contrast, the staff noted that the MRP-227-A report would have the applicant perform ASME Code Section XI required VT-3 visual inspections of core barrel flanges for wear because the components have been defined in the MRP-227-A report as ASME Code Section XI "Existing Program" components.

The staff noted that the Water Chemistry Program would not, by itself, be an acceptable basis for managing loss of material caused by wear in these flanges because the mitigative chemical control activities of the AMP would not have any impact on alleviating the consequences of mechanical-induced aging mechanisms (e.g., wear, fretting or abrasion) that could induce a loss of material aging effect. Thus, the staff did not have sufficient information to conclude that wear would not be applicable to the core barrel flanges or to establish how the Water Chemistry Program would be capable of managing loss of material that might occur in these flange components as a result of wear. The staff also noted that, in LRA Amendment No. 1, the applicant had amended its AMR item on cracking of the core barrel flanges to credit the PWR Vessel Internals Program as the basis for managing cracking in the components instead of the ASME Section XI, Subsections IWB, IWC, and IWD Program and by identifying that the AMP would inspect these components under the EPRI MRP's "Expansion Category" component bases in the MRP-227-A report. The staff questioned this change in the AMR basis because the staff observed that the MRP-227-A report identifies that Westinghouse-designed core barrel flanges are ASME Code Section XI, "Existing Program," core support structure components (i.e., ASME Code Section XI, Examination Category B-N-3 components) and not EPRI MRP defined "Expansion Category" RVI components. Thus, the staff noted that, if the core barrel flanges were ASME Code Section XI, Examination Category B-N-3, components for the CLB, the applicant should have either continued to credit its ASME Section XI, Subsections IWB, IWC, and IWD Program to manage cracking in the components, or credited the PWR Vessel Internals Program for the aging effect by identifying the components as ASME Code Section XI, "Existing Program," components. Therefore, by letter dated September 25, 2012, the staff issued RAI 3.1.2.1-4, Part (b), requesting that the applicant provide both a clarification on why the AMR item on cracking of the core barrel flange in LRA Amendment No. 1 identified this component as an "Expansion Category" component and not as ASME Code Section XI, "Existing Program," components. The staff also requested the applicant to provide its basis on how the Water Chemistry Program, by itself, would be capable of managing loss of material in the core barrel flange that initiates by a wear-induced mechanism (or similar mechanisms such

are fretting or abrasion). Specifically, the staff requested the applicant to clarify whether the core barrel flange is defined in the Callaway CLB as an ASME Code Section XI, Examination Category B-N-3 core support structure component. If the core barrel flange is an ASME Code Section XI, Examination Category B-N-3 component for the CLB, the staff requested the applicant to justify why it had not credited either the PWR Vessel Internals Program's ASME Code Section XI-based "Existing Program" Examination Category protocols or the ASME Section XI Inservice Inspection, Subsections IWB, IWC, IWD Program as the basis for managing both loss of material due to wear and cracking that may occur in the core barrel flange. If the core barrel flange was not defined in the CLB as an ASME Code Section XI, Examination Category B-N-3 core support structure component, the staff requested the applicant to:

(i) identify the RVI "Primary Category" component or components that will be inspected for cracking and loss of material due to wear and will be used to determine whether the core barrel flange will need to be inspected for these aging effects,

(ii) identify the inspection methods and frequency that will be applied to both the "Primary Category" component links and potentially to the core barrel flange as an "Expansion Category" component for those components, and

(iii) justify the "Expansion Category" bases that will be applied to potential inspections of the core barrel flange.

In its response to RAI 3.1.2.1-4, Part (b) dated October 24, 2012, the applicant clarified that the core barrel flange is defined as an ASME Code Section XI, Examination Category B-N-3 core support structure component for the CLB. As part of its response the applicant amended the LRA to change the AMR basis for aging management of the core barrel flange. Specifically, the applicant amended the existing AMR item on cracking of the components to credit the ASME Code Section XI "Existing Program" basis of its PWR Vessel Internals Program as the bases for inspecting and managing cracking of the core barrel flange. The applicant also added a new AMR item to manage loss of material that may occur in the core barrel flange as a result of wear and crediting the ASME Code Section XI, Examination Category B-N-3 examinations as the basis for managing wear in the components. The staff finds the amended AMR bases for the core barrel flange to be acceptable because: (a) the applicant will be implementing the mandated inspections of the components either through implementation of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, or the PWR Vessel Internals Program; and (b) these bases are consistent with bases in GALL Report AMR items IV.B2.RP-382 and IV.B2.RP-345, which recommend that these ASME Code Section examinations be used as the basis for managing loss of material and cracking in these components. The staff's concern described in RAI 3.1.2.1-4, Part (b), is resolved.

The staff noted that, in LRA Amendment No. 1, the applicant provided changes to the AMR items for the following RVI components at Callaway: (a) core barrel girth and axial welds, (b) core barrel outlet nozzles and welds, (c) core support forging, and (d) upper core plate. The staff noted that, in these amended AMR items, the applicant either corrected the aging effect or mechanism consistent with those reported for the components in MRP-227-A or proposed aging management bases under the PWR Vessel Internals Program that were consistent with the recommended aging management bases as proposed in MRP-227-A report and endorsed by the staff for "Primary Category" or "Expansion Category" RVI components. However, the staff has noted that these components could fall into multiple inspection category bases under the

applicant's PWR Vessel Internals Program if the components were also defined in the CLB as ASME Code Section XI, Examination Category B-N-3 core support structure components.

By letter dated September 25, 2012, the staff issued RAI 3.1.2.1-5 requesting that the applicant provide additional clarifications on whether the core barrel girth welds, core barrel axial welds, core barrel outlet nozzles and welds, core support forging, and upper core plate are ASME Code Section XI, Examination Category B-N-3 components for the CLB. If so, the staff requested the applicant to justify why the ASME Code Section XI, Subsection IWB, IWC, IWD, or the ASME Code Section XI "Existing Program" protocols of the PWR Vessel Internals Program have not been credited in addition to the appropriate "Primary Category" or "Expansion Category" bases that have been identified for the components.

In its response dated October 24, 2012, the applicant stated that core barrel girth welds, core barrel axial welds, core barrel outlet nozzles and welds, core support forging, and upper core plate are ASME Code Section XI, Examination Category B-N-3 components. The applicant stated that, although these components are categorized as either "Primary Category" components or "Expansion Category" components, the requirements of ASME Code Section XI, Examination Category B-N-3 are still in effect and may only be altered as allowed by 10 CFR 50.55a (i.e., if a 10 CFR 50.55a relief request is approved for the components).

The applicant also stated that the guidelines provided in MRP-227-A do not reduce, alter, or otherwise affect current ASME Code Section XI or Callaway ISI commitments. The staff finds that the applicant's aging management basis for the core barrel girth welds, core barrel axial welds, core barrel outlet nozzles and welds, core support forging, and upper core plate is acceptable because it clarifies that: (a) the applicant will be applying the PWR Vessel Internals Program and appropriate "Primary Category" or "Expansion Category" inspection basis for the components in the MRP-227-A as part of the basis for managing the age-related effects that are applicable to the components during the period of extended operation; (b) the applicant will also be implementing the ASME Code Section XI, Examination Category B-N-3 inspections of the components, as required by 10 CFR 50.55a; and (c) the applicant's inspection basis for these components is consistent with the AMR item bases for these components in the GALL Report and with the applicant's CLB for complying with applicable 10 CFR 50.55a requirements. The staff's concern described in RAI 3.1.2.1-5 is resolved.

LRA Table 3.1.2-1 provides the applicant's AMR items for managing cracking, loss of fracture toughness, and loss of material in the Callaway ICI support structure, upper and lower tie plates. In the AMR items, the applicant credits the Water Chemistry Program to manage loss of material that may be induced in these components by pitting or crevice corrosion. The applicant also credits a combination of the Water Chemistry Program and the PWR Vessel Internals program to manage any cracking that may occur in the components. The applicant also credits the PWR Vessel Internals Program to manage loss of fracture toughness that might occur in the components. In the AMR items for the upper and lower tie plate components, the applicant identifies that the upper and lower tie plate components are "Expansion Category" components for the PWR Vessel Internals Program.

The staff reviewed the applicant's basis against the criteria for Westinghouse-designed "Expansion Category," components in the MRP-227-A report. The staff was unable to correlate the ICI support structure upper and lower tie plates to any of the components that are listed for Westinghouse-designed RVI components in MRP-227-A Table 3-3 or in MRP-227-A Table 4-6, for Westinghouse "Expansion Category" components. Therefore, the staff was unable to determine which of the MRP-227-A "Primary Category" components would potentially provide

lead indications of aging for the ICI support structure upper and lower tie plates or the types of inspection bases (including method and frequency) that would be applied to the tie plates if expansion inspections were warranted.

By letter dated September 12, 2012, the staff issued RAI 3.1.2.1-2. RAI 3.1.2.1-2, Part (a) requested the applicant to provide clarification on whether the ICI support structure upper and lower tie plates are within the scope of any "Expansion Category" component groupings in Table 4-6 of the MRP-227-A report, and if so, to identify which of the "Expansion Category" component groupings in the report correlated to the Callaway ICI support structure upper and lower tie plates. RAI 3.1.2.1-2, Part (b) requested the applicant to identify which "Primary Category" component or components in Table 4-3 of MRP-227-A will be linked to the ICI support structure upper and lower tie plates, as "Expansion Category" components if these tie plates are not within the scope of any of the "Expansion Category" component groupings in Table 4-6 of the MRP-227-A report. The staff also asked the applicant to:

> [c]larify the "Primary Category" inspection acceptance criteria that would kick in expansion inspections of the tie plates. Identify the inspection method and inspection frequency that would be applied to the tie plates and clarify whether the tie plates would be subject to baseline inspections prior to the period of extended operation, as well as re-inspection basis during the period of extended operation, and define such bases as appropriate.

In its response dated October 15, 2012, the applicant provided its response to RAI 3.1.2.1-2, Requests (a) and (b). In its response the applicant stated that the functions of the ICI support structure, including the BMI column bodies and the upper and lower tie plates, are to protect the flux thimble tubes and to provide a path for the flux thimble tubes into the core from the bottom of the reactor vessel. The applicant stated that the flux thimble tubes are part of the RCPB and that the BMI column bodies are included in MRP-227-A Table 3-3 and MRP-227-A Table 4-6 as "Expansion Category" components. In response to Part (a) the applicant stated that the upper and lower tie plates have the function of supporting the structural integrity of the BMI column bodies to maintain the functions of the BMI column bodies. The applicant also stated that since the tie plates and the BMI column bodies are located in the same area of the reactor and have the same function of protecting the flux thimble tubes, the upper and lower tie plates are included in the same group as the BMI column bodies to be within the scope of "Expansion Category" components. In response to Part (b) the applicant stated that "Primary Category" component link for the ICI support structure upper and lower tie plates are the CRGT lower flange components and that it selected CRGT lower flanges as the "Primary Category" components because they also serve as the "Primary Category" links for the BMI column bodies, which are also "Expansion Category" components for the program.

Based on its review of the applicant's response, the staff noted that the inclusion of the upper and lower tie plates as "Expansion Category" components for the PWR Vessel Internals Program is a conservative plant-specific decision by the applicant that goes beyond the "Expansion Category" components recommendations for Westinghouse-designed PWR RVI components in the MRP-227-A report. The staff also noted that the applicant's selection of the CRGT lower flanges as the "Primary Category" component links for the upper and lower tie plates was a logical selection by the applicant based on their purpose of serving as the "Primary Category" component links for both the BMI column bodies and lower support column bodies as applicable Westinghouse-design "Expansion Category" components. The staff finds this to be an acceptable aging management basis for the upper and lower tie plates and, therefore, finds the applicant response acceptable because: (a) the applicant has conservatively added the ICI

support structure upper and lower tie plates in as additional plant-specific "Expansion Category" components under the PWR Vessel Internals Program; (b) the applicant's decision to inspect the upper and lower tie plates as "Expansion Category" components for the program is consistent with the applicant's basis for inspecting the BMI column bodies and the lower support column bodies as "Expansion Category" components for the program; (c) under this program, the applicant will implement inspections of the BMI column bodies, lower support column bodies, and ICI support structure upper and lower tie plates if evidence of cracking is detected in the CRGT lower flanges; (d) the staff has confirmed that AMR items for the upper and lower tie plates are consistent with AMR bases in GALL Report AMR items IV.B2.RP-292 and IV.B2.RP-293; and (e) this basis represents a conservative decision by the applicant that goes beyond the recommendations in MRP-227-A. The staff finds that this basis serves as one example of the additional plant-specific and conservative decisions made by the applicant that demonstrates the applicant's conformance with the action request in A/LAI No. 2 on the MRP-227-A methodology. The staff's concerns described in RAI 3.1.2.1-2, Requests (a) and (b) are resolved.

LRA Table 3.1.2-1 provides the AMR items for managing loss of material and changes in dimension of the RVI baffle-former assembly. In these AMR items, the applicant credits the Water Chemistry Program to manage loss of material in the RVI baffle-former assembly and the PWR Vessel Internals Program to manage changes in dimension of the RVI baffle-former assembly.

The staff noted that Table 4-3 of the MRP-227-A report includes the EPRI MRP's recommended criteria for performing VT-3 visual inspections of Westinghouse-design baffle-to-former assembly components, including the baffle plates and former plates. In addition, in Table 4-3 of MRP-227-A, the EPRI MRP identifies that the VT-3 examinations on the applicable RVI baffle-former assembly components are used to look for evidence of both changes in dimension that initiates by component distortion or void swelling and cracking that initiates by an IASCC mechanism. The staff noted that LRA Table 3.1.2-1 did not include any AMR items on management of cracking in the plant's baffle plates or former plates. Therefore, it was not evident to the staff which components were specifically within the scope of the AMR items for the "RVI baffle-former assembly" or why cracking caused by IASCC would not need to be identified as an applicable AERM and managed by the applicant "Primary Category" VT-3 inspection bases for baffle plates and former plates in the baffle-former assembly.

By letter dated September 25, 2012, the staff issued RAI 3.1.2.1-3, requesting the applicant to provide its basis on why LRA Table 3.1.2-1 did not include any AMR items on management of cracking of baffle plates and former plates of the baffle-former assembly or why the PWR Vessel Internals Program would not need to be credited to manage cracking caused by IASCC in the baffle plates and former plates, as "Primary Category" components for inspection.

In its response dated October 24, 2012, the applicant stated that, as clarified in the response to RAI 3.1.2.1-1, Part (a), the RVI baffle-former assembly includes the baffle plates and the former plates. The applicant stated that the RVI baffle-to-former assembly components included in LRA Table 3.1.2-1 are consistent with the component description of GALL Report AMR item IV.B2.RP-270 for aging management of the changes in dimension in the RVI baffle-to-former assembly (baffle and former plates). The applicant also stated that the AMR items for these components also include an AMR item on management of loss of material in the components as a result of crevice and pitting corrosion and that the AMR item is consistent with GALL Report AMR item IV.B2.RP-24. The applicant further stated that Table 4-3 of MRP-227-A report identifies that cracking caused by IASCC is an applicable aging effect to be managed

within the scope of MRP-227-A basis for the RVI baffle-to-former assembly components. As part of its response the applicant also amended LRA Table 3.1.2-1 to include an AMR item on management of cracking caused by IASCC in the RVI baffle-former assembly that covers aging management of the baffle plates and former plates and that credits the PWR Vessel Internals Program and the "Primary Category" inspection basis for the baffle and former plates in Table 4.3 of the MRP-227-A report, as the basis for managing cracking of the components during the period of extended operation.

The applicant also provided supplemental information regarding the baffle-edge bolts by letter dated April 23, 2014. In this letter, the applicant stated that, according to information provided by Westinghouse for the RVI components in this commodity group, the Callaway Unit 1 plant design does not include baffle-edge bolts in its core baffle assembly. The applicant amended LRA Table 3.1.2-1 to delete the three AMR item entries for baffle edge bolting (as referenced in LRA Table 3.1.1, items 3.1.1-53 or 3.1.1-59) from the scope of the LRA table. The staff reviewed the plant design documentation and verified that the design of the plant's core baffle assembly does not include baffle-edge bolts. As a result, the staff verified that these components are not within the scope of the applicant's PWR Vessel Internals Program and that the "Primary Category" component recommendations for Westinghouse-designed baffle-edge bolts in EPRI MRP Technical Report No. MRP-227-A do not apply to Callaway Unit 1. Based on this review, the staff reviewed the applicant's claim and LRA amendment and finds them acceptable because the staff has verified that the RVI design does not include baffle-edge bolts.

The staff finds that the applicant's responses are acceptable because: (a) the basis for managing loss of material caused by pitting and crevice corrosion and changes in dimension of the baffle and former plates is consistent with GALL Report AMR items IV.B2.RP-24 and IV.B2.RP-270; and (b) the staff confirmed that the LRA Table 3.1.2-1 AMR, as amended, is consistent with the recommended AMR in GALL Report AMR item IV.B2.RP-294. The staff's concern described in RAI 3.1.2.1-3 is resolved.

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

3.1.2.1.4 Loss of Material due to Pitting and Crevice Corrosion

LRA Table 3.1-1, item 3.1.1-87 addresses the Callaway RVI components made from either stainless steel or nickel alloy materials that are exposed to reactor coolant environment, which will be managed for loss of material due to pitting or crevice corrosion. The LRA credits the Water Chemistry Program to manage this aging effect and mechanism for the stainless steel or nickel alloy RVI components that are exposed to the reactor coolant environment. The staff's evaluation of the applicant's Water Chemistry Program is documented in SER Section 3.0.3.1.2.

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 management of loss of material caused by pitting and crevice corrosion using water chemistry controls that will either prevent initiation of these relevant aging mechanisms or that will mitigate the consequence of the relevant aging effect should loss of material be initiated in the components as a result of pitting or crevice corrosion aging mechanisms. The staff noted that the applicant's basis for managing loss of material because of pitting and crevice corrosion of these components is in conformance with the staff's recommendations in AMR item No. 24 of SRP-LR Table 3.1-1 and the Table 2 AMR items in GALL Report Table IV.B2 that are

referenced to by SRP-LR Table 3.1-1 AMR item No. 24. Therefore, based on this review, the staff finds that the applicant's basis for managing loss of material caused by pitting and crevice corrosion in these RVI components to be acceptable because the staff has confirmed that the applicant's basis is in conformance with the staff's recommended AMR criteria in SRP-LR Table 3.1-1 AMR item No. 24.

The staff concludes that for LRA item 3.1.1-87, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation is Recommended

In LRA Section 3.1.2.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the RCS components and provides information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to general, pitting, and crevice corrosion
- loss of fracture toughness due to neutron irradiation embrittlement
- cracking due to SCC and IGSCC
- crack growth due to cyclic loading
- cracking due to SCC
- cracking due to cyclic loading
- loss of material due to erosion
- cracking due to SCC and IASCC
- loss of fracture toughness due to neutron irradiation embrittlement; change in dimension due to void swelling; loss of preload due to stress relaxation; or loss of material due to wear
- cracking due to PWSCC
- cracking due to fatigue
- cracking due to SCC and fatigue
- loss of material due to wear
- QA for aging management of nonsafety-related components

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 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 3.1.2.2. The staff's review of the applicant's further evaluation follows.

3.1.2.2.1 Cumulative Fatigue Damage

LRA Section 3.1.2.2.1 addresses the applicant's AMR for managing cumulative fatigue damage in RPV and internals; reactor coolant pumps, pressurizer; primary side of the steam generators, and RCPB piping, valves, and other components; and of those steam generator secondary-side components with a fatigue analysis. The applicant stated that fatigue is a TLAA, as defined in 10 CFR 54.3, and is required to be evaluated in accordance with 10 CFR 54.21(c). Additional information for these TLAAs is discussed in LRA Section 4.3.

The applicant identified the following item in LRA Table 3.1-1 that are applicable:

Item 3.1.1-1 - The applicant stated that metal fatigue of RCPB closure bolting (RPV head studs) is a TLAA addressed in LRA Section 4.3.

Item 3.1.1-2 - The applicant stated that metal fatigue and wear analyses of the replacement steam generators are TLAAs addressed in LRA Sections 4.3 and 4.7, respectively.

Item 3.1.1-3 - The applicant stated that metal fatigue of RVI components is a TLAA addressed in LRA Section 4.3.

Item 3.1.1-5 - The applicant stated that metal fatigue of RCPB closure bolting (pump, valve, and pressurizer and steam generator manway and port bolting), reactor vessel inlet and outlet nozzle supports; pressurizer vessel supports, support skirts and flanges; steam generator primary and secondary shells, integral supports, manways, nozzles, and bolting is a TLAA addressed in LRA Section 4.3.

Items 3.1.1-6 and 3.1.1-7 - The staff noted that these AMR items are specifically related to components in a BWR design; therefore, the staff finds it appropriate that the applicant did not address these items in the LRA.

Item 3.1.1-8 - The applicant stated that metal fatigue of steam generator primary and secondary-side pressure boundaries including the lower head, divider plate, primary and secondary manways, nozzles and safe ends is a TLAA addressed in LRA Section 4.3.

Item 3.1.1-9 - The applicant stated that metal fatigue of RCPB piping, reactor coolant pumps, and the pressurizer, postulation of HELB locations, LBB analysis of RCPB piping are TLAAs addressed in LRA Sections 4.3 and 4.7.

Item 3.1.1-10 - The applicant stated that metal fatigue of reactor vessel, ISI corrosion analysis of RPV underclad flaws; and fatigue flaw growth analysis for the cold leg elbow-to-safe end weld and the pressurizer, are TLAAs addressed in LRA Sections 4.3 and 4.7.

For LRA Table 3.1-1, item 3.1.1-4, the applicant stated that the AMR item is not applicable because it has a Westinghouse reactor vessel with no support skirt. The staff reviewed the LRA and FSAR and confirmed that the applicant's LRA does not have any AMR results that are applicable for this item.

The staff reviewed LRA Section 3.1.2.2.1 against the further evaluation criteria in SRP-LR Section 3.1.2.2.1, which states that fatigue is a TLAA as defined in 10 CFR 54.3, and that these TLAAs are to be evaluated in accordance with the TLAA acceptance criteria requirements in 10 CFR 54.21(c)(1) and consistent with SRP-LR Sections 4.3 and 4.7. The staff also reviewed

the AMR items associated with LRA Section 3.1.2.2.1, and determined that the AMR results are consistent with the GALL Report and SRP-LR.

Based on its review, the staff concludes that the applicant has met the SRP-LR Section 3.1.2.2.1 criteria. For those items that apply to LRA Section 3.1.2.2.1, the staff determined that the LRA is consistent with the GALL Report and that the applicant 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). SER Sections 4.3 and 4.7 document the staff's review of the applicant's evaluation of the TLAAs for these components.

3.1.2.2.2 Loss of Material Due to General, Pitting, and Crevice Corrosion

The staff reviewed LRA Section 3.1.2.2.2 against the following criteria in SRP-LR Section 3.1.2.2.2:

(1) LRA Section 3.1.2.2.2.1, associated with LRA Table 3.1-1, item 3.1.1-12, addresses the steam generator upper and lower shell and transition cone exposed to secondary feedwater and steam. The LRA states that the existing program relies on control of water chemistry to mitigate corrosion and ISI to detect loss of material. The LRA also states that augmented inspection is recommended for Westinghouse Models 44 and 51 steam generators, where a high-stress region exists at the shell to transition cone weld, if general and pitting corrosion of the shell is known to exist. The LRA further states that the applicant's steam generators have been replaced with Areva Model 73/19T, therefore the augmented inspection is not applicable.

    The GALL Report states that this aging effect for the component is limited to Westinghouse Models 44 and 51 steam generators, where a high-stress region exists at the shell to transition cone weld. In its review of components associated with item 3.1.1-12, the staff confirmed that the applicant has replaced its steam generators with Areva Model 73/19T steam generators and finds that the augmented inspection is not applicable to the applicant's steam generators.

(2) LRA Section 3.1.2.2.2.2, associated with LRA Table 3.1-1, item 3.1.1-12, addresses the steam generator upper and lower shell assembly exposed to secondary feedwater and steam. The LRA states that further evaluation of the effectiveness of the Water Chemistry Program is required for applicants that have replaced only the bottom part of their steam generators, generating a cut in the middle of the transition cone, and consequently a new transition cone closure weld. The LRA further states that the applicant's replacement steam generators did not require a cut and associated field weld in the middle of the steam generator transition cone; therefore, further evaluation is not required.

    In its review of components associated with item 3.1.1-12, the staff confirmed that the applicant's replacement steam generators did not require a cut in the transition cones. Therefore, there is no field weld in the middle of the applicant's steam generators transition cones. The staff finds that this item is not applicable for further evaluation.

3.1.2.2.3 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement

The staff reviewed LRA Section 3.1.2.2.3 against the following criteria in SRP-LR Section 3.1.2.2.3:

(1) LRA Section 3.1.2.2.3.1, associated with LRA Table 3.1-1, item 3.1.1-13, addresses RPV steel (with or without stainless steel cladding) reactor vessel beltline shell, nozzles, and welds exposed to reactor coolant and neutron flux with an aging effect of loss of fracture toughness due to neutron irradiation embrittlement. LRA Section 3.1.2.2.3.1 states that the evaluation of this TLAA is addressed in LRA Section 4.2. The staff finds that this is consistent with SRP-LR Section 3.1.2.2.3, item 1 criteria and is, therefore, acceptable. The staff's evaluation of the TLAA for reactor vessel neutron embrittlement is documented in SER Section 4.2.

Based on its review, the staff concludes that the applicant has met the SRP-LR Section 3.1.2.2.3, item 1 criteria. For those items that apply to LRA Section 3.1.2.2.3.1, 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 function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). SER Section 4.2 documents the staff's review of the applicant's evaluation of the TLAAs for these components.

(2) LRA Section 3.1.2.2.3.2, associated with LRA Table 3.1-1, item 3.1.1-14, addresses RPV steel (with or without cladding) reactor vessel beltline shell, nozzles, and welds as well as safety injection nozzles components exposed to reactor coolant, and neutron flux, which are being managed for loss of fracture toughness due to neutron irradiation embrittlement by the Reactor Vessel Surveillance Program. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Reactor Vessel Surveillance Program manages loss of fracture toughness caused by neutron irradiation embrittlement in the reactor vessel beltline shell, nozzles, and welds exposed to reactor coolant and neutron flux.

The staff reviewed LRA Section 3.1.2.2.3.2 against the criteria in SRP-LR Section 3.1.2.2.3, item 2, which states that loss of fracture toughness caused by neutron irradiation embrittlement could occur for PWR reactor vessel beltline shell, nozzle, and welds exposed to reactor coolant and neutron flux. The SRP-LR also states that a reactor vessel materials surveillance program monitors neutron irradiation embrittlement of the reactor vessel, and that these programs are plant-specific. The SRP-LR further states that GALL Report, Chapter XI, Section M31, gives specific recommendations for an acceptable AMP.

SER Section 3.0.3.2.10 documents the staff's evaluation of the applicant's Reactor Vessel Surveillance Program. The staff finds the applicant's proposal to manage aging using the Reactor Vessel Surveillance Program acceptable, because use of this program to manage neutron irradiation embrittlement of the reactor vessel beltline materials is consistent with the GALL Report and the SRP-LR. In addition the staff finds that Reactor Vessel Surveillance Program is consistent with the recommendations of the GALL Report AMP XI.M31.

Based on the program identified, the staff concludes that the applicant's program meets SRP-LR Section 3.1.2.2.3, item 2 criteria. For those items associated with LRA Section 3.1.2.2.3.2, 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 function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(3) LRA Section 3.1.2.2.3.3, associated with LRA Table 3.1-1, item 3.1.1-15, addresses reduction in fracture toughness. The applicant stated that reduction in fracture

toughness is a plant-specific TLAA for Babcock and Wilcox (B&W) reactor internals and is not applicable to Callaway which has Westinghouse reactor internals.

SRP-LR Section 3.1.2.2.3, item 3, states that reduction in fracture toughness is a plant-specific TLAA for B&W reactor internals to be evaluated for the period of extended operation in accordance with the staff's safety evaluation concerning "Demonstration of the Management of Aging Effects for the Reactor Vessel Internals," Babcock and Wilcox Owners Group report number BAW-2248, which is included in BAW-2248A, dated March 2000. The staff confirmed that SRP-LR Section 3.1.2.2.3, item 3, is not applicable to Callaway because it is a Westinghouse-designed PWR. The staff noted that a TLAA associated with the reduction in fracture toughness and ductility does not exist for the applicant's CLB. The staff's review of the absence of TLAA is documented in SER Section 4.3.3.2. The staff also noted that the effect of loss of fracture toughness and reduced material ductility are managed for Westinghouse reactor internals with the applicant's PWR Vessel Internal Program. The staff's evaluation of the PWR Vessel Internal Program is documented in SER Section 3.0.3.1.5.

Based on the information above, the staff concludes that the staff's guidance in SRP-LR Section 3.1.2.2.3, item 3, does not apply to Callaway because the TLAA documented in BAW-2248A is only applicable to B&W-designed PWRs.

3.1.2.2.4 Cracking Due to Stress Corrosion Cracking and Intergranular Stress Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.4 against the following criteria in SRP-LR Section 3.1.2.2.4:

(1) LRA Section 3.1.2.2.4, associated with LRA Table 3.1-1, item 3.1.1-16, addresses cracking due to SCC and IGSCC. The applicant stated that this item is applicable to BWR plants only. SRP-LR Section 3.1.2.2.4, item 1, states that cracking due to SCC and IGSCC may occur in the stainless steel and nickel-alloy BWR top head enclosure vessel flange leak detection lines. The staff finds that SRP-LR Section 3.1.2.2.4, item 1, is not applicable to Callaway because it is a PWR, and the staff guidance in this SRP-LR section is only applicable to BWR-designed reactors.

(2) LRA Section 3.1.2.2.4.2, associated with LRA Table 3.1-1, item 3.1.1-17, addresses cracking due to SCC and IGSCC in stainless steel BWR isolation condensers that are exposed to a BWR reactor coolant environment. The applicant stated that this item is applicable to BWR plants only. SRP-LR Section 3.1.2.2.4, item 2, states that cracking caused by SCC and IGSCC could occur in stainless steel BWR isolation condenser components exposed to reactor coolant. The staff finds that SRP-LR Section 3.1.2.2.4, item 2, is not applicable to Callaway because it is a PWR, and the staff guidance in this SRP-LR section is only applicable to BWR-designed reactors.

3.1.2.2.5 Crack Growth Due to Cyclic Loading

LRA Section 3.1.2.2.5, associated with LRA Table 3.1-1, item 3.1.1-18, addresses intergranular separations (underclad cracks) in welds that are used to join cladding to RPV shell or nozzle forgings made from SA-508 Class 2 alloy steel materials and are exposed to the reactor coolant environment. The applicant addressed the further evaluation criteria of the SRP-LR by stating that no underclad cracks have been detected or analyzed for the Callaway RPV. By letter dated May 3, 2012, the applicant amended LRA Section 3.1.2.2.5 identifying that crack growth due to cyclic loading as a TLAA. The applicant stated that its evaluation of the TLAA is addressed

separately in LRA Section 4.7.4. The staff's evaluation of the TLAA is documented in SER Section 4.7.4.2.

Based on its review, the staff concludes that the applicant has met the SRP-LR Section 3.1.2.2.5 criteria. For those items that apply to LRA Section 3.1.2.2.5, 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 function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). SER Section 4.7 documents the staff's review of the applicant's evaluation of the TLAAs for these components.

3.1.2.2.6 Cracking Due to Stress Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.6 against the following criteria in SRP-LR Section 3.1.2.2.6:

(1) LRA Section 3.1.2.2.6.1, associated with LRA Table 3.1-1, item 3.1.1-19, addresses the management of cracking due to SCC in PWR reactor vessel flange leakage detection lines and reactor vessel BMI guide tubes exposed to a reactor coolant environment.

The criteria in SRP-LR Section 3.1.2.2.6, item 1, states that cracking due to SCC could occur in PWR stainless steel reactor vessel flange leakage detection lines and BMI guide tubes that are exposed to a reactor coolant environment. SRP-LR Section 3.1.2.2.6, item 1, also states that the GALL Report recommends further evaluation to ensure that this aging effect will be adequately managed and that a plant-specific AMP be evaluated to ensure that this aging effect is adequately managed during the period of extended operation.

The applicant addressed the further evaluation criteria in SRP-LR Section 3.1.2.2.6, item 1, by stating that cracking due to SCC of the BMI guide tubes will be managed using a combination of its Water Chemistry Program and ASME Section XI Inservice Inspection, Subjections IWB, IWC, and IWD Program. The applicant also identified that cracking due to SCC of the reactor vessel flange leakage detection line will be managed by the ASME Section XI Inservice Inspection, Subjections IWB, IWC, and IWD Program. SER Sections 3.0.3.1.1 and 3.0.3.1.2 document the staff's evaluation of the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and Water Chemistry Program, respectively.

In its review of components associated with item 3.1.1-19, the staff finds that for the stainless steel BMI guide tubes, the applicant has met the further evaluation criteria. The LRA states that cracking due to SCC of the BMI guide tubes is managed 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 3.1.2.2.6.1 against the criteria in SRP-LR Section 3.1.2.2.6, item 1. In its review of the stainless steel BMI guide tubes associated with LRA Table 3.1-1, item 3.1.1-19, the staff finds the applicant's proposal to manage aging using the Water Chemistry and ASME Section XI Inservice Inspection Programs acceptable because: (a) the Water Chemistry Program will mitigate the potential development and progress of the aging effect, by limiting and controlling contaminants that may contribute to SCC; and (b) the ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD Program will confirm the effectiveness of the Water Chemistry Program. The staff confirmed that these components fall under examination category B-P, and will require a periodic VT-2 examination every RFO and during system leakage testing. The extent and frequency of

these examinations provide reasonable assurance that leakage, if present would be identified as reactor coolant leakage and corrected during scheduled plant outages.

In its review of the applicant's reactor vessel flange leakage detection lines, which are also associated with LRA Table 3.1-1, item 3.1.1-19; the staff noted that the applicant stated that its reactor vessel flange leak detection line is made of nickel alloy with a normal operating environment of air with borated water leakage. In addition, the applicant stated that cracking due to SCC of the reactor vessel flange leak detection line will be managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The staff finds the applicant's proposal to manage aging of the reactor vessel flange leakage detection line using the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program acceptable because, during normal operation of the reactor, the environment for the applicant's reactor vessel flange leakage detection line is not expected to be in contact with borated water. Therefore, the environment air with borated water leakage would be expected only in the unlikely event that leakage is occurring past the applicant's O-ring seal. Furthermore, the applicant's reactor vessel flange leakage detection line is fabricated from nickel alloy. The staff noted that the GALL Report includes entries for nickel alloys exposed to air with borated water leakage. These entries indicate that an aging effect requiring management is not required for this material-environment combination. Therefore, the staff finds that the applicants proposal to use its ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program acceptable because, if leakage is occurring past the O-ring in the flange and the flange leak detection line develops through wall cracking, the credited ISI would be performed with sufficient frequency to detect the leakage and take appropriate corrective actions.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.6, item 1 criteria. For those items associated with LRA Section 3.1.2.2.6.1, 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 function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(2) LRA Section 3.1.2.2.6.2, associated with LRA Table 3.1-1, item 3.1.1-20, addresses CASS Class 1 piping, piping components, and piping elements exposed to reactor coolant, which will be managed for cracking due to SCC. The LRA states that the carbon content for RCS fittings and piping pieces do not meet the NUREG-0313 criterion of less than 0.035 percent based on review of the CMTRs of the applicant's CASS piping components. The LRA also states that cracking due to SCC for CASS RCS piping components exposed to reactor coolant is managed by the Water Chemistry Program and is augmented by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. In addition the applicant stated that it has determined that the molybdenum and ferrite values are below the thermal aging embrittlement screening threshold. The applicant further stated that these CASS reactor coolant piping components are not susceptible to the aging effect of thermal aging embrittlement and it is not required to include flaw evaluation methodology for these CASS components.

In its review of components associated with LRA Table 3.1-1, item 3.1.1-20, the staff finds the applicant's proposal to manage aging using the Water Chemistry and ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Programs acceptable because the Water Chemistry Program will mitigate the potential for SCC, while the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program will

confirm the effectiveness of the Water Chemistry Program. The staff's evaluation of the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program and Water Chemistry Program is documented in SER Sections 3.0.3.1.1 and 3.0.3.1.2 respectively.

Based on the programs identified, the staff concludes that the applicant's program meets SRP-LR Section 3.1.2.2.6, item 2 criteria. For those items associated with LRA Section 3.1.2.2.6.2, 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 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 Cyclic Loading

LRA Section 3.1.2.2.7, associated with LRA Table 3.1-1, item 3.1.1-21, addresses cracking due to cyclical loading in steel and stainless steel BWR isolation condensers that are exposed to a BWR reactor coolant environment. The applicant stated that this item is not applicable to Callaway because the staff's further evaluation recommendation is only applicable to BWR designs. The staff reviewed LRA Sections 2.3.1 and 3.1, and the Callaway FSAR and finds the applicant determination acceptable because Callaway is a PWR design that does not include any steel or stainless steel isolation condenser components exposed to a reactor coolant environment.

3.1.2.2.8 Loss of Material Due to Erosion

LRA Section 3.1.2.2.8, associated with LRA Table 3.1-1, item 3.1.1-22, addresses loss of material due to erosion in steel steam generator feedwater impingement plates and supports exposed to secondary feedwater. The applicant stated that this item is not applicable for further evaluation because Callaway's steam generators do not have feedwater impingement plates.

In its review of the LRA and FSAR of components associated with LRA Table 3.1-1, item 3.1.1-22, the staff confirmed that the applicant's replacement steam generators do not have feedwater impingement plates. Therefore staff finds the applicant determination that this item is not applicable acceptable.

3.1.2.2.9 Cracking Due to Stress Corrosion Cracking and Irradiation-Assisted Stress Corrosion Cracking

LRA Section 3.1.2.2.9, associated with LRA Table 3.1-1, item 3.1.1-23, addresses cracking due to SCC and IASCC in stainless steel or nickel alloy PWR RVI components in inaccessible locations exposed to reactor coolant and neutron flux. The staff's evaluation of item 3.1.1-23 is documented in SER Section 3.1.2.2.10 below.

3.1.2.2.10 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement Change in Dimension Due to Void Swelling, Loss of Preload Due to Stress Relaxation, or Loss of Material due to Wear

LRA Section 3.1.2.2.9, associated with LRA Table 3.1-1, item 3.1.1-23, addresses cracking due to SCC and IASCC in stainless steel or nickel alloy PWR RVI components in inaccessible locations exposed to reactor coolant and neutron flux. The applicant stated that this aging effect will be managed by its PWR Vessel Internals Program. The criteria in SRP-LR Section 3.1.2.2.9 states that cracking due to SCC and IASCC could potentially occur in the

inaccessible locations for stainless steel and nickel-alloy “Primary Category” and “Expansion Category” PWR RVI components. SRP-LR Section 3.1.2.2.9 also states that, if aging effects are identified in accessible locations, the GALL Report recommends further evaluation of the aging effects in inaccessible locations on a plant-specific basis to ensure that this aging effect is adequately managed.

LRA Section 3.1.2.2.10, associated with LRA Table 3.1-1, item 3.1.1-24, addresses nickel alloy and stainless steel PWR RVI components that are exposed to the reactor coolant (including impacts of neutron flux) environment, which will be managed for loss of fracture toughness due to neutron irradiation embrittlement; changes in dimension due to void swelling; loss of preload due to thermal and irradiation enhanced stress relaxation; or loss of material due to wear by the applicant’s PWR Vessel Internals Program. The criteria in SRP-LR Section 3.1.2.2.10 states that these aging effects and mechanisms could potentially occur in the inaccessible locations for stainless steel and nickel-alloy “Primary Category” and “Expansion Category” PWR RVI components. SRP-LR Section 3.1.2.2.10 also states that, if aging effects are identified in accessible locations, the GALL Report recommends further evaluation of the aging effects in inaccessible locations on a plant-specific basis to ensure that this aging effect is adequately managed.

The applicant addressed the further evaluation criteria in SRP-LR Sections 3.1.2.2.9 and 3.1.2.2.10 by stating that the PWR Vessel Internals Program examines one hundred percent of the volume/area of each accessible stainless steel and nickel alloy RVI primary and expansion inspection category component that is subject to cracking. The applicant stated that the minimum examination coverage for primary and expansion inspection categories is 75 percent of the component's total (accessible plus inaccessible) inspection area or volume or, when addressing a set of like components (e.g., bolting), that the inspections examine a minimum sample size of 75 percent of the total population of like components. The applicant also stated that if defects are discovered in the 75 percent sample size, the information will be entered into its CAP to evaluate the results of the examination to ensure the intended functions are maintained until the next scheduled examination. In LRA Amendment No. 1, dated April 25, 2012, the applicant stated that the methodology in non-proprietary WCAP-17096-NP, Revision 2, “Reactor Internals Acceptance Criteria Methodology and Data Requirements,” (ADAMS Accession No. ML101460156), will be used as the basis for evaluating flaws or degraded areas in the RVI components.

LRA Table 3.1-1, item 3.1.1-23, is based on the AMR criteria in SRP-LR Section 3.1.2.2.9 and SRP-LR Table 3.1-1, item No. 23, which references AMR item IV.B2.RP-268 in the GALL Report. Similarly, LRA Table 3.1-1, item 3.1.1-24, is based on the AMR criteria in SRP-LR Section 3.1.2.2.10 and SRP-LR Table 3.1-1, item No. 24, which references AMR item IV.B2.RP-269 in the GALL Report. The staff’s evaluation of the applicant’s PWR Vessel Internals Program is documented in SER Section 3.0.3.1.5. The applicant’s PWR Vessel Internals Program is based, in part, on conformance with the recommended inspection and flaw evaluation criteria in EPRI Report No. 1022863, “Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A),” which was approved in the staff’s revised Safety Evaluation, Revision 1, dated December 16, 2011. In this topical report, the EPRI MRP defines “Primary Category” RVI components as PWR RVI components that are either highly susceptible to effects of aging caused by any active degradation mechanism, or components that have a degree of tolerance for a specific degradation mechanism but for which no leading highly susceptible or accessible component exists. The EPRI MRP defines “Expansion Category” components as RVI components that are moderately or highly susceptible to the effects of aging caused by one or more active

degradation mechanisms but for which the functionality analyses indicated that these components have a degree of tolerance to the aging effects associated with these degradation mechanisms. The EPRI MRP recommends that "Primary Category" components be periodically inspected as part of the RVI management programs. In contrast to this, the EPRI MRP recommends that "Expansion Category" components be inspected only if unacceptable degradation is identified during inspections of the "Primary Category" components that are linked to the "Expansion Category" components.

In its review of LRA AMR items 3.1.1-23 and 3.1.1-24, the staff noted that the criteria in SRP-LR Sections 3.1.2.2.9 and 3.1.2.2.10 are based on EPRI MRP's recommended inspection coverage criteria for PWR RVI components, as given in the MRP-227-A report and approved in the MRP-227-A report, Safety Evaluation, Revision 1, Section 3.3.1 for "Primary Category" PWR RVI components and MRP-227-A report, Safety Evaluation, Revision 1, Section 3.3.2 for "Expansion Category" PWR RVI components. The staff also noted that the applicant's bases in LRA Sections 3.1.2.2.9 and 3.1.2.2.10 were consistent and in conformance with the criteria in Sections 3.3.1 and 3.3.2 of the Safety Evaluation, Revision 1 on the MRP-227-A report, but did not address how the applicant would evaluate relevant aging effects in inaccessible component areas or in inaccessible components that are part of a population of redundant RVI components (e.g., specific RVI bolting components, some of which are accessible to inspection technologies and some that are not accessible to inspection technologies). The staff also noted that the methodology in WCAP-17096-NP is currently under staff review pending staff's acceptance. Thus, the staff noted that the applicant was credited a report methodology that had yet to be accepted by the staff for use.

By letter dated September 25, 2012, the staff issued RAI 3.1.2.2-1, Parts (a) and (b), to address these concerns. In RAI 3.1.2.2-1, Part (a), for those "Primary Category" or "Expansion Category" inspections that revealed evidence of aging, the staff requested the applicant to clarify whether the evaluations of structural integrity would include an evaluation of the relevant aging effects in those areas of an RVI component that are inaccessible to the applicable inspection method, or for redundant components like bolting, in those redundant components that were inaccessible to inspection. If the applicable evaluations of aging would include an assessment of inaccessible areas (or for redundant RVI component like bolts, inaccessible components), the staff requested the applicant to clarify how the evaluations of the inaccessible areas, or inaccessible redundant components would be performed. In RAI 3.1.2.2-1, Part (b), the staff requested the applicant to justify its basis for relying on WCAP-17096-NP as part of the monitoring and evaluation bases for the PWR Vessel Internals Program, when the methodology in WCAP-17096-NP has yet to be approved by the staff for use. The staff also requested the applicant to clarify and justify how it would address any limitations or A/LAIs (or their equivalent) that may be issued on the report's methodology, which might be identified in the staff's Safety Evaluation that will be issued on the report's methodology. In addition, the staff requested the applicant to clarify and justify how the evaluation of flaws or degraded areas would be evaluated in the RVI components at Callaway if WCAP-17096-NP is rejected for use by the staff.

By letter dated October 24, 2012, the applicant responded to RAI 3.1.2.2-1, Pars (a) and (b). In its response to Part (a), on how the inaccessible areas or components would be evaluated under the PWR Vessel Internals Program, the applicant stated the following:

> For those "Primary Category" or "Expansion Category" examinations that reveal evidence of aging, the corrective action process evaluation would consider the applicability of the aging in the inaccessible areas or redundant components.

> Examination acceptance criteria and expansion criteria will be consistent with MRP-227-A Table 5-3 for Westinghouse plants.
>
> Examination acceptance criteria identify the visual examination relevant condition(s), or signal based level or relevance of an indication, that requires formal disposition for acceptability. Based on the identified condition, 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 repair or replace the item. The evaluation would consider extent of the condition in inaccessible areas/components consistent with the associated accessible primary component or expansion component evaluation.
>
> Expansion criteria are intended to form the basis for decisions about expanding the set of components selected for examination or other aging management activity, in order to determine whether the level of degradation represented by the detected conditions has extended to other components judged to be less affected by the degradation. The expansion criteria of MRP-227-A Table 5-3 would be used to determine when the aging detected in the primary component would require the additional examinations identified for the expansion component(s). Expansion criteria evaluations for accessible primary components will include consideration of inaccessible areas/components associated with the primary component in the evaluation.

The staff noted that the response demonstrates that the applicant will be evaluating how RVI inaccessible areas or inaccessible RVI components would be evaluated under the AMP was consistent with basis in Section 5 of the MRP-227-A report and the staff's recommended guidance for assessing these RVI inaccessible areas or components in Sections 3.3.1 and 3.3.2 of the staff's revised Safety Evaluation, Revision 1, on the MRP-227-A report methodology. Therefore, the staff finds this basis to be acceptable because it is in conformance with the MRP-227-A report and with the staff's bases for achieving appropriate RVI component inspection coverages and for evaluating RVI inaccessible areas or inaccessible RVI components in the Safety Evaluation, Revision 1, on the MRP-227-A report. The staff's concern described in RAI 3.1.2.2-1, Part (a), is resolved.

In its response to RAI 3.1.2.2-1, Part (b), the applicant stated that, if WCAP-17096-NP is approved for use by the staff with any limitations or A/LAIs as identified in the staff's Safety Evaluation, the implementation of the PWR Vessel Internals Program will be supplemented consistent with condition or action items in the staff's Safety Evaluation approving the WCAP-17096-NP methodology. The applicant also stated that if WCAP-17096-NP is rejected for use by the staff, Callaway engineering evaluations for RVIs will be performed consistent with available industry guidance (e.g., EPRI-MRPs, PWR Owners Group Reports, etc.). The staff finds this basis acceptable because the applicant will either: (a) use a staff-endorsed version of WCAP-17096-NP, as subject to any staff limitations or actions that are issued in the staff's Safety Evaluation on that report's methodology, to establish the acceptance criteria and evaluate the results of inspections performed in accordance with the MRP-227-A methodology; or (b) use applicable industry guidance recommendations for this purpose. Therefore, the staff's concern described in RAI 3.1.2.2-1, Part (b). is resolved.

Based on its review, the staff finds that the applicant has met the further evaluation criteria in SRP-LR Sections 3.1.2.2.9 and 3.1.2.210 and that the basis in the PWR Vessel Internals Program for achieving minimum inspection coverage and evaluating inaccessible areas or

inaccessible redundant components is acceptable because: (a) the staff has confirmed that the applicant's PWR Vessel Internals Program includes inspection coverage scopes that are consistent with those approved by the staff for programs based on the criteria of the MRP-227-A report, and (b) any evaluations of structural integrity for the RVI components would include applicable assessments of aging in the inaccessible areas of the components areas or in those inaccessible components that are part of a redundant population of RVI components (such as bolting). For those AMR items that apply to LRA Sections 3.1.2.2.9 and 3.1.2.210, the staff determines that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended functions will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.11 Cracking Due to Primary Water Stress Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.11 against the following criteria in SRP-LR Section 3.1.2.2.11:

(1) LRA Section 3.1.2.2.11.1, associated with LRA Table 3.1-1, item 3.1.1-25, addresses foreign operating experience in steam generators with a similar design to that of Westinghouse Model 51 which has identified extensive cracking due to PWSCC in steam generator divider plate assemblies fabricated of Alloy 600 and/or the associated Alloy 600 weld materials, even with proper primary water chemistry (EPRI TR-1014982).

The applicant addressed the further evaluation criteria of the SRP-LR through Commitment No. 34, stating: (1) the applicant would perform an inspection of each steam generator, with an examination technique capable of detecting PWSCC, to assess the condition of the divider plate welds; or (2) the applicant stated it would perform an analytical evaluation of the steam generator divider plate welds in order to establish a technical basis which concludes that the steam generator RCS pressure boundary is adequately maintained with the presence of steam generator divider plate weld cracking; or (3) If results of industry and NRC studies and operating experience document that potential failure of the steam generator RCS pressure boundary caused by PWSCC cracking of steam generator divider plate welds is not a credible concern, Commitment No. 34 will be revised to reflect that conclusion.

(2) LRA Section 3.1.2.2.11.2, associated with LRA Table 3.1-1, item 3.1.1-25, addresses cracking due to PWSCC that could occur in steam generator nickel alloy tube-to-tube sheet welds exposed to reactor coolant. The applicant addressed the further evaluation criteria of the SRP-LR through Commitment No. 35, which state the following:

- [Union Electric Company (Ameren Missouri) will] [p]erform a one-time inspection of a representative number of tube-to-tubesheet welds in each steam generator to determine if PWSCC cracking is present. If weld cracking is identified, the condition will be resolved through repair or engineering evaluation to justify continued service, as appropriate, and an ongoing monitoring program will be established to perform routine tube-to-tubesheet weld inspections for the remaining life of the steam generators; or
- [p]erform an analytical evaluation of the steam generator tube-to-tubesheet welds in order to establish a technical basis which concludes that the structural integrity of the steam generator tube-to-tubesheet interface is adequately maintained with the presence of tube-to-tubesheet weld cracking. Establish a technical basis

which concludes that the steam generator tube-to-tubesheet welds are not required to perform a [RCPB] function.

In its review of Commitment Nos. 34 and 35, the staff noted that it needed additional information regarding the applicant's management of aging effects for the tube-to-tubesheet welds and divider plate. By letter dated September 20, 2012, the staff issued RAI 3.1.2.2.11-1, Parts (a), (b), and (c). The staff's discussion of RAI 3.1.2.2.11-1, Parts (a), (b), and (c) is documented below.

In RAI 3.1.2.2.11-1, Part (b), the staff requested the applicant to provide the following information regarding the divider plate and associated Commitment No. 34:

- The staff requested the applicant to clarify the configuration of the divider plate assembly. In particular, the staff requested the applicant clarify if the divider plate assembly (i.e., the stub runner) is welded to the carbon steel tubesheet or the tubesheet cladding. The staff also requested the applicant clarify whether the divider plate is welded to the stainless steel channel head cladding or the low alloy carbon steel shell. In addition, the staff requested the applicant to provide the weld material for the welds.
- The staff requested the applicant to discuss plans for clarifying the commitment (Commitment No.34) such that the inspection technique used will be qualified to detect cracking in the divider plate assembly given that cracks have been observed outside the weld region (i.e., in the heat affected zone).
- The staff requested the applicant to clarify the frequency for this inspection, or to state if it is a one-time inspection.
- The staff requested the applicant to discuss its plans to remove the last two options in the commitment since, if such analyses become available, they could be submitted to the NRC for review and if approved, may serve as a basis for revising the commitment. The staff noted that if additional analyses become available that demonstrate pressure boundary integrity is adequately maintained with divider plate weld cracking, or if studies indicate that failure of the pressure boundary is not a concern, then the commitment may be revised at that time.

In its response to RAI 3.1.2.2.11-1, Part (b), dated October 24, 2012, the applicant stated that based on the steam generator design drawings, there is no stub runner at the interface between the divider plate (called partition plate in applicant's steam generator design drawings) and the tubesheet of the steam generators. The applicant also stated that there is a small rectangular Alloy 690 closure plate (also known as a filler plate on other steam generator designs) installed at the Alloy 690 divider plate to stainless steel clad primary head and Alloy 82/182 clad tube sheet junctions. The applicant further stated that the most stressed portions of the channel head in contact with the primary coolant are welded with Alloy 15 and the most stressed areas are associated with the divider plate to primary head and tube sheet junctions. In addition, the applicant stated that the steam generator design drawings show the following weld and buttering materials:

- divider plate to tubesheet cladding: Alloy 152 weld and buttering materials
- divider plate to closing plate: Alloy 152 weld materials
- divider plate to primary head cladding: Alloy 152 weld material
- closing plate to tubesheet cladding: Alloy 152 weld and buttering materials
- closing plate to tubesheet ring: Alloy 152 weld and stainless steel buttering

- closing plate to primary head cladding: Alloy 152 weld materials

Additionally, the applicant revised LRA Table A4-1, Commitment No. 34, to state that: (a) the inspection will include the divider plate assembly and associated welds, {b) the inspection will be a one-time inspection, and (c) the analytical evaluation of the divider plate welds will be submitted to the staff for review and approval.

In RAI 3.1.2.2.11-1, Part (a), the staff requested the applicant to provide the following information related regarding the tube-to-tubesheet weld and associated Commitment No. 35:

- The staff requested the applicant to discuss its plans to modify Commitment No. 35 to indicate that the technical basis for the redefinition of the RCPB will be submitted to the staff for review and approval as part of the license amendment process prior to redefining the RCPB.
- The staff requested the applicant to discuss whether an analytical evaluation may be performed to assess whether the welds are susceptible to PWSC. If it is determined that the welds are not susceptible to primary water stress corrosion cracking, and the staff agrees with this determination, the staff requested the applicant to discuss the plans for using this as the basis for not performing inspections of the welds. Additionally, the staff requested the applicant discuss plans to modify Commitment No. 35 to reflect the response to the staff's request.
- The staff requested the applicant to confirm that the inspection technique(s) used to inspect the welds will be capable of detecting PWSCC. In addition, the staff requested that the applicant discuss its plans to modify Commitment No. 35 to reflect that the inspection technique(s) will be capable of detecting PWSCC.

In its response to RAI 3.1.2.2.11-1, Part (a), dated October 24, 2012, the applicant revised LRA Table A4-1, Commitment No. 35, to state that a redefinition of the RCPB will be submitted as part of a license amendment request requiring approval from the staff and that the examination technique(s) used by the applicant will be capable of detecting PWSCC in the tube-to-tubesheet welds. Additionally, the applicant revised Commitment No. 35 to allow for performing an analytical evaluation of the steam generator tube-to-tubesheet welds to determine their susceptibility to PWSCC, and to submit the analysis for staff review if it is determined that the welds are not susceptible to PWSCC and do not require inspection.

In RAI 3.1.2.2.11-1, Part (c), the staff requested information regarding both the divider plate and tube-to-tubesheet weld Commitments No. 34 and 35. The staff requested the applicant to discuss its plans to include the divider plate and tube-to-tubesheet weld commitments in the FSAR supplement. The staff also requested the applicant to discuss plans for revising the commitments to specify that an inspection of each steam generator, to assess the condition of the divider plate assembly and tube-to-tubesheet weld, will be performed during a specific time period (e.g., the inspections will be performed no earlier than 3 years before the period of extended operation and no later than 2 years after entering the period of extended operation). The staff also requested that for the actual timeframe chosen the applicant consider the amount of operating time on the steam generator.

In its response to to RAI 3.1.2.2.11-1, Part (c), dated October 24, 2012, the applicant revised LRA Section A1.9 and 3.1.2.2.11 to be consistent with the changes to LRA Table A4-1 Commitments No. 34 and 35 as noted above. The applicant also revised LRA Table A4-1, Commitments No. 34 and 35, to reflect implementation schedule between

fall 2025 and fall 2029, when the replacement steam generators will have been in service for more than 20 years.

The staff finds the applicant response to RAI 3.1.2.2.11-1, Parts (a), (b), and (c), acceptable because the revisions to Commitment No. 34 and No. 35 will ensure that the applicant gets approval from the staff prior to redefining the RCPB and that the inspection techniques used to examine the tube-to-tubesheet welds are qualified to detect PWSCC. Additionally, the staff finds that the revisions to the LRA and Commitments No.34 and 35 are acceptable because they will ensure that the applicant gets approval from the staff before discontinuing the inspections for PWSCC in the tube-to-tubesheet or divider plate welds should the applicant perform an analytical evaluation finding that the welds are not susceptible to PWSCC. The staff finds that this will provide adequate time for the the staff to independently review the conclusions of the analysis prior to the applicant taking action. The staff also finds that an inspection between fall of 2025 and fall 2029 will ensure that the steam generators will have sufficient operating time to ensure that any degradation that may occur will have had time to take place. Therefore, the staff's concerns described in RAI 3.1.2.2.11-1, Parts (a), (b), and (c), are resolved.

In a supplemental letter dated February 14, 2014, the applicant revised the timeframe of submittal for Options 2 or 3 (if chosen) of LRA Table A4-1, Commitment No. 34 and Option 2 (if chosen) of Commitment No. 35. The applicant revised the commitment implementation schedules for each commitment such that, if an Option 2 or 3 is chosen, then the respective results would be submitted for NRC review in the fall, 2023. The staff finds the applicant's supplemental information acceptable because the period the applicant provided for completing Commitment Nos. 34 and 35, Option 2 or 3 (if chosen) and submitting the respective analysis will allow the staff time to review and disposition the analysis prior to the plant entering the period of extended operation.

The staff's evaluation of the applicant's Water Chemistry Program is documented in SER Section 3.0.3.1.2. In its review of components associated with LRA Table 1 item 3.1.1-25, the staff finds that the applicant has met the further evaluation criteria. The staff finds that the applicant's proposal to manage cracking of the divider plate and tube-to-tubesheet weld using the Water Chemistry Program and confirming the adequacy of this program through inspection is acceptable because proper management of water chemistry may mitigate PWSCC in the divider plate and tube-to-tube sheet welds. The staff finds that confirming the adequacy of the Water Chemistry Program through inspections will detect the presence of PWSCC in the divider plate or tube-to-tubesheet welds should it occur and allow for the applicant to take the appropriate corrective actions. Alternatively, should the applicant establish a technical basis that concludes that the steam generator RCPB is adequately maintained with the presence of cracking in the steam generator divider plate or the results of industry and staff studies and operating experience document that PWSCC of the steam generator divider plate is not a credible concern, then confirming that PWSCC in the divider plate does not occur through inspections will no longer be necessary. Similarly, should the applicant establish a technical basis that concludes that the steam generator RCPB is adequately maintained with the presence of cracking in the steam generator tube-to-tubesheet welds, or that the tube-to-tubesheet weld is not susceptible to PWSCC, then confirming that PWSCC in the tube-to-tubesheet welds does not occur through inspections will no longer be needed.

Based on the program identified, the staff concludes that the applicant's program meets the criteria of SRP-LR Section 3.1.2.2.11. For those AMR items associated with LRA Section 3.1.2.2.6, 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 function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.12 Cracking Due to Fatigue

LRA Section 3.1.2.2.12, associated with LRA Table 3.1-1, item 3.1.1-26, addresses cracking due to fatigue in Combustion Engineering-designed RVI core support barrel assembly lower flange welds, upper internals assembly fuel alignment plates, and lower support structure core support plates exposed to a reactor coolant environment. The applicant stated that this item is not applicable to Callaway because this item is only applicable to Combustion Engineering-designed RVI components and because the RVI assemblies at Callaway were designed by Westinghouse. However, the applicant stated that the evaluation of cumulative fatigue damage due to fatigue for the Westinghouse-designed RVI assemblies and components at the Callaway Plant is addressed in LRA Section 3.1.2.2.1.

LRA Table 3.1-1, item 3.1.1-26, is based on the AMR criteria in SRP-LR Section 3.1.2.2.12 and SRP-LR Table 3.1-1, item No. 26, which invokes AMR items for Combustion Engineering-designed core support barrel assembly lower flange welds, upper internals assembly fuel alignment plates, and lower support structure core support plates in AMR items IV.B3.RP-333, IV.B3.RP-338, and IV.B3.RP-343 of the GALL Report. SRP-LR Section 3.1.2.2.12 states that EPRI 1016596, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines," (MRP-227-A, Revision 0) identifies cracking due to fatigue as an aging effect that can occur for the lower flange weld in Combustion Engineering-designed core support barrel assembly lower flange welds, upper internals assembly fuel alignment plates, and lower support structure core support plates. SRP-LR states that the GALL Report recommends that inspection for cracking in this component be performed if acceptable fatigue life cannot be demonstrated by TLAA through the period of extended operation as defined in 10 CFR 54.3.

The staff reviewed LRA Sections 2 and FSAR and noted that FSAR defines the Callaway Plant as a Westinghouse-designed 4-loop light water reactor. Based on this review, the staff finds that the applicant has provided an acceptable basis for claiming that the criteria in SRP-LR Section 3.1.2.2.12 and SRP-LR Table 3.1-1, item No 26, is not applicable to Callaway because the staff has confirmed that: (a) the recommendations in SRP-LR Section 3.1.2.2.12 and SRP-LR Table 3.1-1, item No 26, are only applicable to specific Combustion Engineering-designed RVI components, and (b) Callaway is a Westinghouse-designed PWR.

The staff confirmed that the applicant has addressed metal fatigue of the Callaway RVI core support structure components in LRA Section 3.1.2.2.1 and has included the metal fatigue TLAAs for these components in LRA Section 4.3.3 and LRA Table 4.3-5. The staff evaluation of these LRA Sections is documented in SER Sections 3.1.2.2.1 and 4.3.3.2.

3.1.2.2.13 Cracking Due to Stress Corrosion Cracking and Fatigue

LRA Section 3.1.2.2.13, associated with LRA Table 3.1-1, item 3.1.1-27, addresses nickel alloy guide tube support pins of Westinghouse CRGT assemblies, exposed to reactor coolant and neutron flux. LRA Section 3.1.2.2.13 states that this item is not applicable because this item is

only applicable to nickel-alloy guide tube support pins and Callaway's guide tube support pins are made of stainless steel.

The criteria in SRP-LR Section 3.1.2.2.13 invoke AMR Item IV.B2.RP-355 of the GALL Report and state that cracking due to SCC and fatigue could occur in nickel alloy CRGT assembly guide tube support pins exposed to reactor coolant and neutron flux. GALL Report, AMR item IV.B2.RP-355, recommends further evaluation of a plant-specific AMP to ensure this aging effect is adequately managed.

In comparison, LRA Section B2.1.6, "PWR Vessel Internals," indicates that based on industry operating experience the applicant replaced the Alloy X-750 guide tube support pins (also called split pins) with strain-hardened (cold-worked) 316 stainless steel pins during RFO 13 (spring 2004), to reduce the susceptibility of the support pins to SCC. The LRA also states that there were no cracked Alloy X-750 pins discovered during the replacement process. It is noted that Alloy X-750 is a type of nickel alloy.

In addition, LRA Table 3.1.2-1 indicates that cracking of the stainless steel CRGT support pins is managed by the Water Chemistry Program and PWR Vessel Internals Program (Existing Program Components) under LRA item 3.1.1-53. Furthermore, LRA Table 3.1.2-1 indicates that cracking of the stainless steel CRGT support pins is also managed by ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program under LRA item 3.1.1-32.

After the issuance of SRP-LR and the GALL Report, the staff issued Revision 1 of the Safety Evaluation of EPRI MRP-227-A, Revision 0, "Pressurized Water Reactor (PWR) Internals Inspection and Evaluation Guidelines," dated December 16, 2011. Section 3.2.5.3, "Evaluation of the Adequacy of Plant-Specific Existing Programs," of Revision 1 of the Safety Evaluation states:

Westinghouse guide tube support pins are made from either 316 stainless steel or Alloy X750. There have been issues with cracking of the original Alloy X750 pins and many licensees have replaced them with type 316 stainless steel materials. Applicants/licensees shall evaluate the adequacy of their plant-specific existing program and ensure that the aging degradation is adequately managed during the extended period of operation for both Alloy X750 and type 316 stainless steel guide tube support pins (split pins). Therefore, it is recommended that the evaluation consider the need to replace the Alloy X750 support pins (split pins), if applicable, or inspect the replacement type 316 stainless steel support pins (split pins) to ensure that cracking has been mitigated and that aging degradation is adequately monitored during the extended period of operation.

Revision 1 of the Safety Evaluation of MRP-227 also identified the aging management for the CRGT support pins as A/LAI 3. Therefore, the staff needed additional information regarding the applicant's aging management and inspections to manage cracking of the replacement stainless steel CRGT support pins as described below.

By letter dated August 16, 2012, the staff issued RAI 3.1.1.27-1 requesting that the applicant clarify whether the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is the existing program that is used to manage cracking of these stainless steel CRGT support pins in conjunction with the PWR Vessel Internals Program. The staff also requested that the applicant provide the technical basis for why the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is adequate to ensure that aging degradation is adequately monitored during the period of extended operation. In addition, the staff requested that the applicant clarify whether the VT-3 examination under Examination Category B-N-3

includes examination of the support pins to manage cracking. The staff further requested that the applicant confirm whether the applicant's actions in response to A/LAI 3 are consistent with the existing staff-mandated and vendor/supplier-recommended inspection monitoring bases for the applicant's stainless steel CRGT support pins.

In its response dated September 20, 2012, the applicant stated that LRA Table 3.1.2-1 identifies that cracking of stainless steel CRGT support pins is managed by the Water Chemistry Program and the PWR Vessel Internals Program, consistent with GALL Report AMR item B2.RP-346. The applicant also clarified that as described in LRA Table 3.1.2-1, the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is the existing program that is used to manage cracking of the support pins in conjunction with the PWR Vessel Internals Program, consistent with GALL Report item IV.B2.RP-382. The applicant further stated that it has replaced the Alloy X750 CRGT support pins (split pins) with 316 stainless steel materials and the support pins are included in the Existing Program Components of MRP-227-A, Table 3-3. In addition, the applicant indicated that the LRA includes the stainless steel CRGT support pins in response to the December 2011 staff Safety Evaluation, Section 3.2.5.3 and there are no staff-mandated or vendor/supplier-recommended inspection requirements for the CRGT support pins in the applicant's CLB.

In its response regarding the examination method, the applicant stated that, consistent with MRP-227-A, Category B-N-3 examinations of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program manage the aging degradation of Existing Program Components. The applicant also stated that consistent with IWB-3520, Examination Category B-N-3 uses a VT-3 examination, and IWB-3200(b) permits supplemental surface or volumetric examinations to determine the extent of relevant conditions detected by the VT-3 examinations. The applicant further stated that therefore, the aging degradation of the CRGT support pins is adequately managed by Category B-N-3 examinations of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program in conjunction with the PWR Vessel Internals Program during the period of extended operation.

In its review, the staff finds the applicant's response acceptable because: (a) the applicant clarified that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is the existing program to manage cracking of the replacement stainless steel support pins of the CRGT components in conjunction with the PWR Vessel Internals Program; (b) VT-3 examinations in accordance with ASME Code Examination Category B-N-3 are used to detect and manage cracking of the support pins, consistent with the GALL Report; (c) ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program also includes adequate provisions to correct relevant conditions that would be detected from the VT-3 examinations; and (d) the applicant's CLB does not include staff-mandated or vendor/supplier-recommended inspection requirements, other than the ASME Code ISI, for the CRGT support pins so that the applicant's aging management for the support pins are consistent with its CLB. RAI 3.1.1.27-1 is resolved.

The staff's evaluations of the Water Chemistry Program, PWR Vessel Internals Program and ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program are documented in SER Sections 3.0.3.1.2, 3.0.3.1.5, and 3.0.3.1.1, respectively. In its review, the staff finds the applicant's use of the Water Chemistry Program acceptable to manage the aging effect because: (a) the monitoring and controlling of water chemistry is performed periodically in accordance with the EPRI PWR water chemistry guidelines as recommended by GALL Report AMP XI.M2, "Water Chemistry," and (b) the chemistry control can minimize the concentrations of detrimental contaminants and mitigate the SCC in the components. In addition, the staff finds

the applicant's use of the PWR Vessel Internals Program and ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program acceptable to manage the aging effect because the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is identified as the existing program for the CRGT support pins in conjunction with the PWR Vessel Internals Program, consistent with the GALL Report, and the VT-3 examinations of these components in accordance with the ASME Code Section XI Examination Category B-N-3 are adequate to detect and manage cracking of these components.

Based on the programs identified, the staff concludes that the applicant's programs meet the criteria in SRP-LR Section 3.1.2.2.13. For those items associated with LRA Section 3.1.2.2.13, 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 function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.14 Loss of Material due to Wear

LRA Section 3.1.2.2.14, associated with LRA Table 3.1-1, item 3.1.1-28, addresses loss of material due to wear in Westinghouse-designed RVI CRGT assembly support pins (split pins) and ICI lower thimble tubes exposed to a reactor coolant environment. The applicant stated that this item is not applicable to the Callaway LRA with respect to the design of the Callaway CRGT split pins because this item is only applicable to Westinghouse-design CRGT split pins that are made from nickel alloy materials and the CRGT spilt pins at the Callaway Plant are made from stainless steel.

LRA Table 3.1-1, item 3.1.1-28 is based on the AMR criteria in SRP-LR Section 3.1.2.2.14 and SRP-LR Table 3.1-1, item No. 28, which invokes the AMR item for managing loss of material due to wear of Westinghouse-design CRGT split pins in GALL Report AMR item IV.B2.RP-356. SRP-LR Section 3.1.2.2.14 states that loss of material due to wear could occur in Westinghouse-designed CRGT split pins that are made from nickel alloy materials. SRP-LR Section 3.1.2.2.14 also states that the AMR item IV.B2.RP-356 on management of wear in Westinghouse-designed CRGT split pins recommends further evaluation of a plant-specific AMP to ensure wear will be adequately managed during the period of extended operation.

LRA Section B2.1.6, "PWR Vessel Internals," is based in part on the recommended guidelines for Westinghouse-designed RVI components in EPRI Report No. 1022863, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A)." This EPRI Report was approved in a revised staff Safety Evaluation, Revision 1, dated December 16, 2011. This Safety Evaluation included appropriate A/LAIs that were to be responded to for incoming PWR LRAs. The staff noted that the basis in SRP-LR Section 3.1.2.2.14 is based in part on the criteria for managing wear in Westinghouse-designed CRGT split pins, as defined in the MRP-227-A report and impacted by the staff's evaluation in Section 3.2.5.3 of the Safety Evaluation, Revision 1, on the MRP-227-A methodology. In this section of the revised Safety Evaluation, the staff stated that Westinghouse CRGT split pins are made from either 316 stainless steel or Alloy X-750 (i.e., a nickel alloy material). The staff stated that there have been issues with cracking and wear of the original Alloy X-750 pins and that many licensees have replaced them with cold worked, type 316 stainless steel materials. Thus, in the Safety Evaluation, the staff recommended that license renewal applicants for Westinghouse-design light water reactors should evaluate the adequacy of their plant-specific existing programs and ensure that the aging degradation is adequately managed during the extended period of operation for CRGT split pins made from either Alloy X-750 or stainless steel

materials. Thus, the staff recommended that applicants should either consider the need to replace CRGT split pins made from Alloy X-750 materials, if applicable, or inspect their replacement stainless steel CRGT split pins to ensure that potential cases of wear would be adequately monitored during the extended period of operation. The staff identified this recommendation as A/LAI No. 3 on the MRP-227-A methodology.

The staff noted that the LRA does not currently include Callaway's responses to the A/LAIs on MRP-227-A, including the response to A/LAI No. 3 as made relative to the applicant's basis for managing cracking and inspecting the CRGT spilt pins at Callaway. By letter dated September 25, 2012, the staff issued RAI B2.1.6-4, requesting that the applicant provide its basis for omitting responses to the applicable A/LAIs on MRP-227-A methodology that are determined to be applicable to Westinghouse-designed RVI components at Callaway.

By letter dated October 24, 2012, the applicant provided its response to RAI B2.1.6-4. The staff's evaluation of the applicant's response to RAI B2.1.6-4 is documented in SER Section 3.0.3.1.5, which provides the staff's evaluation of the applicant's PWR Vessel Internals Program and the applicant's response basis for A/LAI No. 3. As described in SER Section 3.0.3.1.5, the staff found the applicant had appropriately resolved the request in A/LAI No. 3 because: (a) the applicant had already replaced the previous CRGT split pins that were made from Inconel X-750 materials with CRGT split pins made from cold-worked Type 316 stainless steel materials; (b) the applicant was crediting its ASME Code Section XI Examination Category B-N-3 examinations as the basis for managing loss of material and cracking that might occur in the CRGT split pins during the period of extended operations; and (c) this basis was in conformance with the staff's recommendation in A/LAI No. 3.

However, the staff has noted that, in LRA Table 3.1.2-1, the applicant only credited its Water Chemistry Program as the basis for managing loss of material in the CRGT split pins. In contrast, the staff noted that, in Table 3-3 of the MRP-227-A report, the EPRI MRP identifies that loss of material caused by wear is an applicable aging effect for CRGT split pins. Thus, the staff noted that the implementation of the Water Chemistry Program would not be an acceptable basis for managing loss of material that would initiate by mechanical mechanisms such as wear, abrasion or fretting because the mitigative chemical control activities of the AMP would not have any impact on alleviating the consequences of loss of material initiating from these types of mechanical aging mechanisms. Thus, the staff did not have sufficient information to conclude that wear would not be applicable to the CRGT split pins at Callaway or how loss of material caused by wear could be adequately managed solely through implementation of the Callaway Water Chemistry Program. Therefore, by letter dated September 25, 2012, the staff issued RAI 3.1.2.1-4, Parts (a) and (b). RAI 3.1.2.1-4, Part (a), requested that the applicant provide the basis as to why loss of material caused by wear was not identified as an applicable AERM for the CRGT split pins when this AERM is identified in the MRP-227-A report for these components. If loss of material caused by wear is an applicable AERM for CRGT split pins, the staff requested the applicant to justify its basis for managing loss of material in the CRGT split pins using only the Water Chemistry Program. The staff's description and evaluation of RAI 3.1.2.1-4, Part (b), is documented in SER Section 3.1.2.1.3.

The applicant responded to RAI 3.1.2.1-4, Part (a) in a letter dated October 24, 2012. In its response to RAI 3.1.2.1-4, Part (a), the applicant stated that the CRGT split pins are designated as ASME Code Section XI, Examination Category B-N-3 components for the CLB. As part of its response the applicant amended the AMR item in LRA Table 3.1.2-1 on cracking of the CRGT split pins to add loss of material as an additional aging effect that is within the scope of the AMR item (i.e., in addition to cracking) and to indicate that it would be using the PWR Vessel Internals

Program as an alternative basis for conforming to the guidance in GALL Report AMR item IV.B2.RP-382. The applicant also stated that it will be using the "Existing Program" bases of the PWR Vessel Internals Program as the basis for managing cracking and loss of material in the CRGT split pins and for implementing the existing Examination Category B-N-3 visual (VT-3) examinations that are mandated for these components in accordance with the requirements in 10 CFR 50.55a and Section XI of the ASME Code. The staff confirmed that the applicant adequately amended the LRA the AMR item in its October 24, 2012, letter.

Based on this review, the staff finds that the applicant has provided an acceptable alternative basis for managing loss of material due to wear (and cracking) in the CRGT split pins because: (a) the applicant will still be using its ASME Code Section XI ISI of the CRGT splits pins as the basis for managing loss of material and cracking in the components; (b) the applicant will be using the "Existing Program" bases of its PWR Vessel Internals Program as an alternative basis for implementing the mandated ASME Code Section XI, Examination Category B-N-3 visual examinations of these components in lieu of using ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program to implement them; and (c) this demonstrates an acceptable alternative basis for implementing mandated ASME Code Section XI requirements for the components that are mandated in 10 CFR 50.55a and recommended in GALL Report AMR item IV.B2.RP-382. Therefore, the staff's concern described in RAI 3.1.2.1-4, Part (a), is resolved.

3.1.2.2.15 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA Program.

3.1.2.2.16 Operating Experience

SER Section 3.0.5, "Operating Experience for Aging Management Programs," documents the staff's evaluation of the applicant's consideration of operating experience of aging management programs.

3.1.2.3 AMR Results 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 the 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 AMR 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 AMR item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the AMR item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that the intended

function(s) will be maintained consistent with the CLB 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

The staff reviewed LRA Table 3.1.2-1, which summarizes the results of AMR evaluations for the reactor vessel and internals component groups.

Nickel Alloy Reactor Vessel Flange Leak Monitoring Tubing Exposed to Borated Water Leakage. In LRA Table 3.1.2-1, the applicant stated that nickel alloy reactor vessel flange leak monitoring tubing exposed to borated water leakage will be managed for cracking by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The AMR item cites generic note F, and plant-specific note 1. Plant-specific note 1 states the following:

> [The GALL Report] does not address cracking of nickel-alloy reactor vessel flange leak monitoring tube with an internal environment of reactor coolant leakage. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD [P]rogram (B2.1.1) manages the cracking of the nickel-alloy reactor vessel flange leak monitoring tube with an internal environment of reactor coolant leakage.

The staff reviewed the associated items in the LRA and confirmed that the GALL Report does not include entries for nickel-alloy reactor vessel flange leak monitoring tubing exposed to air with borated water leakage (internal). Therefore, the staff finds the applicant's use of generic note F appropriate.

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 has entries for vessel flange leak detection lines fabricated from stainless steel, and recommends that a plant-specific aging management program be evaluated. The staff noted that the applicant addressed cracking for this component. Specifically, LRA Section 3.1.2.2.6, item 1, is associated with LRA Table 3.1-1, item 3.1.1-19, which in part also addresses the aging management of cracking in PWR reactor vessel flange leakage detection lines, under the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The staff finds the applicant's use of plant-specific note 1, appropriate because, during normal operations the environment for the reactor vessel flange leak monitoring line is not expected to be exposed to borated water. The staff finds that during normal operations, the reactor vessel flange leak detection line would only be exposed to borated water, if there is leakage past the vessel O-ring. Therefore, the staff finds the applicants proposal to use its ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program acceptable, because if leakage does occur past the O-ring, and results in leakage of the flange monitoring tubing, the applicant's credited examinations during ISIs would detect the leakage.

SER Section 3.0.3.1.1 documents the staff's evaluation of the applicant's ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. SER Section 3.1.2.2.6.1, item 1 documents the staff's evaluation of the applicant's further evaluation associated with its reactor vessel flange leak monitoring tubing.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL

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

3.1.2.3.2 Reactor Vessel, Internals, and Reactor Coolant System—Summary of Aging Management Evaluation—Reactor Coolant System—LRA Table 3.1.2-2

The staff reviewed LRA Table 3.1.2-2, which summarizes the results of AMR evaluations for the RCS component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the RCS component groups are consistent with the GALL Report.

3.1.2.3.3 Reactor Vessel, Internals, and Reactor Coolant System—Summary of Aging Management Evaluation—Pressurizer—LRA Table 3.1.2-3

The staff reviewed LRA Table 3.1.2-3, which summarizes the results of AMR evaluations for the pressurizer component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the pressurizer component groups are consistent with the GALL Report.

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

The staff reviewed LRA Table 3.1.2-4, which summarizes the results of AMR evaluations for the steam generators component groups.

Nickel Alloy Steam Generator Tubes Exposed to Secondary Water (loss of material). In LRA Table 3.1.2-4, the applicant stated that nickel alloy steam generator tubes exposed to secondary water will be managed for loss of material due to wear by the TLAA for replacement steam generator tubes as described in LRA Section 4.7.9. The AMR item in the LRA table cites generic note H, which indicates that the applicant's material, environment, aging effect, and aging management combination is not evaluated in the GALL Report.

In addition, LRA Table 3.1.2-4 includes another AMR item, associated with LRA Table 1 AMR item 3.1.1-77, to manage the same aging effect of this component using the Steam Generators Program, consistent with GALL Report item IV.D1.RP-233. Therefore, the staff noted that the applicant proposed use of the steam generator tube TLAA and Steam Generators Program to manage loss of material caused by wear for the steam generator tubes.

The staff's evaluations of the applicant's Steam Generators Program and replacement steam generator tube wear TLAA are documented in SER Sections 3.0.3.1.7 and 4.7.9, respectively. The staff finds the applicant's proposal to manage aging using the Steam Generators Program acceptable because the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), as described in LRA Amendment No. 9 dated September 20, 2012, that the effects of wear on the intended function of the steam generator tubes will be adequately managed by the Steam Generators Program. The staff finds that the Steam Generators Program includes inspections of the steam generator tubes, assessment of tube integrity, and plugging and repair activities for degraded tubes, which are adequate to detect and manage steam generator tube wear.

Nickel Alloy Steam Generator Tubes Exposed to Secondary Water (reduction in heat transfer). During its review of the AMR items in LRA Table 3.1.2-4 associated with SG tubes, the staff noted that heat transfer was listed as an intended function of the SG tubes, but reduction of heat

transfer was not cited as an applicable aging effect. By letter dated September 20, 2012, the staff issued RAI 3.1.2.4-1, requesting the applicant to identify how the reduction of heat transfer aging effect would be managed for nickel alloy steam generator tubes. In its response letter dated October 24, 2012, the applicant stated that it revised LRA Table 3.1.2-4 to include an AMR item that identifies the Steam Generators Program for verifying the effectiveness of the Water Chemistry Program in managing the aging effect of reduction of heat transfer due to fouling on the nickel alloy steam generator tube external surfaces in a secondary water environment. The applicant stated that LRA Section 3.1.2.1.4, Appendix A1.9, and Appendix B2.1.9 were also revised to include an aging effect of reduction of heat transfer. Additionally, the applicant stated, in part, that an aging effect of reduction of heat transfer due to fouling is not an applicable aging effect for the primary side of the steam generator tubes based on the decision of the Steam Generator Task Force (meeting summary, ADAMS Accession No. ML110670317, February 18, 2011). The staff's evaluations of the applicant's Water Chemistry and Steam Generators AMPs are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.7, respectively.

The staff noted that the applicant's revision to LRA Table 3.1.2-4 states that nickel alloy steam generator tubes exposed to secondary water will be managed for reduction of heat transfer by the Steam Generators and the Water Chemistry AMPs. The revision also cites generic note H and plant-specific note 5 for the AMR item, that the reduction in heat transfer due to fouling is a potential aging effect/mechanism for steam generator tubes in secondary water, and that the GALL Report, Revision 2, does not address the aging effect of reduction in heat transfer for this combination of component, material, and environment.

The staff noted that this material and environment combination is identified in the GALL Report, which states that nickel alloy steam generator tubes exposed to secondary water (external) are susceptible to cracking, loss of material, and cumulative fatigue damage, and recommends GALL Report AMP XI.M2, Steam Generators, and XI.M19, Water Chemistry, to manage the aging effects. The applicant addressed the GALL Report identified aging effects for this component, material, and environment combination in other AMR items in LRA Table 3.1.2-4.

The staff reviewed the applicant's response to RAI 3.1.2.4-1 and finds the applicant's proposal to manage reduction of heat transfer using its Water Chemistry and Steam Generator AMPs acceptable because maintaining proper secondary water chemistry will minimize the amount of sludge deposits that can lead to a reduction in heat transfer in the steam generators. Periodic cleaning of the steam generator secondary side internals, including tubes and tubesheet, will also act to remove accumulated deposits from the steam generator, thus ensuring that the heat transfer ability of the tubes is not hindered. Additionally, based on the discussion between the Steam Generator Task Force and the NRC on February 18, 2011, it was agreed that primary side fouling is not an issue in the United States; therefore, a separate AMR line item would not be needed for the reduction of heat transfer due to fouling of nickel alloy steam generator tubes exposed to primary water. The staff's concerns with RAI 3.1.2.4-1 are resolved.

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

3.1.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the reactor vessel, RVIs, RCS, pressurizer, and steam generators components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2 Aging Management of Engineered Safety Features Systems

This section of the SER documents the staff's review of the applicant's AMR results for the ESF systems components and component groups of the following systems:

- containment spray system
- containment integrated leak rate testing system
- containment hydrogen control system
- containment purge system
- high pressure coolant injection (HPCI) system
- RHR system

3.2.1 Summary of Technical Information in the Application

LRA Section 3.2 provides AMR results for the ESF systems components and component groups. LRA Table 3.2-1, "Summary of Aging Management Programs in Chapter V of NUREG-1801 for Engineered Safety Features," provides a summary comparison of its AMRs to those evaluated in the GALL Report for ESF systems components and component groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included issue reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.2.2 Staff Evaluation

The staff reviewed LRA Section 3.2 to determine if the applicant provided sufficient information to demonstrate that the effects of aging for ESF systems components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will 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 of AMPs to ensure the applicant's claim that certain AMPs were consistent with the GALL Report. The purpose of this audit was to examine the applicant's AMPs and related documentation and to confirm the applicant's claim of consistency with the corresponding GALL Report AMPs. The staff did not repeat its review of the matters described in the GALL Report. The staff's evaluations of the AMPs are documented in SER Section 3.0.3.

The staff reviewed the AMRs to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did confirm that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. Details of the staff's evaluation are discussed in SER Section 3.2.2.1.

During its review, the staff also selected AMRs consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the SRP-LR Section 3.2.2.2 acceptance criteria. The staff's evaluations are documented in SER Section 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.

The staff's review of the ESF systems 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 systems components is documented in SER Section 3.0.3.

Table 3.2-1 Staff Evaluation for ESF Systems Components in the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, Steel Piping, piping components, and piping elements exposed to Treated water (borated) (3.2.1-1)	Cumulative fatigue damage caused by fatigue	Fatigue is a time-limited aging analysis (TLAA) to be evaluated for the period of extended operation. See SRP, Section 4.3 "Metal Fatigue," for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1)).	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.2.2.2.1)
Steel (with stainless steel cladding) Pump casings exposed to Treated water (borated) (3.2.1-2)	Loss of material caused by cladding breach	A plant-specific AMP is to be evaluated Reference NRC Information Notice 94-63, "Boric Acid Corrosion of Charging Pump Casings Caused by Cladding Cracks."	Yes	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.2.2)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel Partially-encased tanks with breached moisture barrier exposed to Raw water (3.2.1-3)	Loss of material caused by pitting and crevice corrosion	A plant-specific AMP is to be evaluated for pitting and crevice corrosion of tank bottom because moisture and water can egress under the tank caused by cracking of the perimeter seal from weathering.	Yes	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.2.3(1))
Stainless steel Piping, piping components, and piping elements; tanks exposed to Air – outdoor (3.2.1-4)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	External Surfaces Monitoring of Mechanical Components	Consistent with the GALL Report (see SER Section 3.2.2.2.3(2))
Stainless steel Orifice (miniflow recirculation) exposed to Treated water (borated) (3.2.1-5)	Loss of material caused by erosion	A plant-specific AMP is to be evaluated for erosion of the orifice caused by extended use of the centrifugal HPSI pump for normal charging. See LER 50-275/94-023 for evidence of erosion.	Yes	Water Chemistry and One-Time Inspection	Not applicable to Callaway (see SER Section 3.2.2.2.4)
Steel Drywell and suppression chamber spray system (internal surfaces): flow orifice; spray nozzles exposed to Air – indoor, uncontrolled (Internal) (3.2.1-6)	Loss of material caused by general corrosion; fouling that leads to corrosion	A plant-specific AMP is to be evaluated	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.2.5)
Stainless steel Piping, piping components, and piping elements; tanks exposed to Air – outdoor (3.2.1-7)	Cracking caused by stress corrosion cracking	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	External Surfaces Monitoring of Mechanical Components	Consistent with the GALL Report (see SER Section 3.2.2.2.6)
Aluminum, copper-alloy (>15% Zn or >8% Al) piping, piping components, and piping elements exposed to air with borated water leakage (3.2.1-8)	Loss of material caused by boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion"	No	Boric Acid Corrosion	Consistent with the GALL Report (see SER Section 3.2.2.1.1)
Steel External surfaces, Bolting exposed to Air with borated water leakage (3.2.1-9)	Loss of material caused by boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion"	No	Boric Acid Corrosion	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Cast austenitic stainless steel Piping, piping components, and piping elements exposed to Treated water (borated) >250 °C (>482 °F), Treated water >250 °C (>482 °F) (3.2.1-10)	Loss of fracture toughness caused by thermal aging embrittlement	Chapter XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)"	No	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.1.1)
Steel Piping, piping components, and piping elements exposed to Steam, Treated water (3.2.1-11)	Wall thinning caused by flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.1.1)
Steel, high-strength Closure bolting exposed to Air with steam or water leakage (3.2.1-12)	Cracking caused by cyclic loading, stress corrosion cracking	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.1.1)
Steel; stainless steel Bolting, Closure bolting exposed to Air – outdoor (External), Air – indoor, uncontrolled (External) (3.2.1-13)	Loss of material caused by general (steel only), pitting, and crevice corrosion	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity	Consistent with the GALL Report
Steel Closure bolting exposed to Air with steam or water leakage (3.2.1-14)	Loss of material caused by general corrosion	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.1.1)
Copper alloy, nickel alloy, steel; stainless steel, stainless steel, steel; stainless steel bolting, closure bolting exposed to any environment, air – outdoor (external), raw water, treated borated water, fuel oil, treated water, air – indoor, uncontrolled (external) (3.2.1-15)	Loss of preload caused by thermal effects, gasket creep, and self-loosening	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity	Consistent with the GALL Report
Steel Containment isolation piping and components (Internal surfaces), Piping, piping components, and piping elements exposed to Treated water (3.2.1-16)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Aluminum, Stainless steel Piping, piping components, and piping elements exposed to Treated water (3.2.1-17)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.1.1)
Stainless steel Containment isolation piping and components (Internal surfaces) exposed to Treated water (3.2.1-18)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report
Stainless steel Heat exchanger tubes exposed to Treated water, Treated water (borated) (3.2.1-19)	Reduction of heat transfer caused by fouling	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with GALL Report (see SER Section 3.2.2.1.1)
Stainless steel Piping, piping components, and piping elements; tanks exposed to Treated water (borated) >60 °C (>140 °F) (3.2.1-20)	Cracking caused by stress corrosion cracking	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with GALL Report (see SER Section 3.2.2.1.2)
Steel (with stainless steel or nickel-alloy cladding) Safety injection tank (accumulator) exposed to Treated water (borated) >60 °C (>140 °F) (3.2.1-21)	Cracking caused by stress corrosion cracking	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One–Time Inspection"	No	Not applicable	Not applicable to Callway (see SER Section 3.2.2.1.1)
Stainless steel Piping, piping components, and piping elements; tanks exposed to Treated water (borated) (3.2.1-22)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One–Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report (see SER Section 3.2.2.1.3)
Steel Heat exchanger components, Containment isolation piping and components (Internal surfaces) exposed to Raw water (3.2.1-23)	Loss of material caused by general, pitting, crevice, and microbiologically - influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel Piping, piping components, and piping elements exposed to Raw water (3.2.1-24)	Loss of material caused by pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.1.1))
Stainless steel Heat exchanger components, Containment isolation piping and components (Internal surfaces) exposed to Raw water (3.2.1-25)	Loss of material caused by pitting, crevice, and microbiologically -influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.1.1)
Stainless steel Heat exchanger tubes exposed to Raw water (3.2.1-26)	Reduction of heat transfer caused by fouling	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.1.1)
Stainless steel, Steel Heat exchanger tubes exposed to Raw water (3.2.1-27)	Reduction of heat transfer caused by fouling	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.1.1)
Stainless steel Piping, piping components, and piping elements exposed to Closed-cycle cooling water >60 °C (>140 °F) (3.2.1-28)	Cracking caused by stress corrosion cracking	Chapter XI.M21A, “Closed Treated Water Systems”	No	Closed Treated Water Systems	Consistent with the GALL Report
Steel Piping, piping components, and piping elements exposed to Closed-cycle cooling water (3.2.1-29)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No	Closed Treated Water Systems	Consistent with the GALL Report
Steel Heat exchanger components exposed to Closed-cycle cooling water (3.2.1-30)	Loss of material caused by general, pitting, crevice, and galvanic corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No	Closed Treated Water Systems	Consistent with the GALL Report
Stainless steel Heat exchanger components, Piping, piping components, and piping elements exposed to Closed-cycle cooling water (3.2.1-31)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No	Closed Treated Water Systems	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper alloy heat exchanger components, piping, piping components, and piping elements exposed to closed-cycle cooling water (3.2.1-32)	Loss of material caused by pitting, crevice, and galvanic corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Closed Treated Water Systems	Consistent with the GALL Report
Copper alloy, stainless steel heat exchanger tubes exposed to closed-cycle cooling water (3.2.1-33)	Reduction of heat transfer caused by fouling	Chapter XI.M21A, "Closed Treated Water Systems"	No	Closed Treated Water Systems	Consistent with the GALL Report
Copper-alloy (>15% Zn or >8% Al) piping, piping components, and piping elements, heat exchanger components exposed to closed-cycle cooling water (3.2.1-34)	Loss of material caused by selective leaching	Chapter XI.M33, "Selective Leaching"	No	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.1.1)
Gray cast iron motor cooler exposed to treated water (3.2.1-35)	Loss of material caused by selective leaching	Chapter XI.M33, "Selective Leaching"	No	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.1.1)
Gray cast iron piping, piping components, and piping elements exposed to closed-cycle cooling water (3.2.1-36)	Loss of material caused by selective leaching	Chapter XI.M33, "Selective Leaching"	No	Selective Leaching	Consistent with the GALL Report
Gray cast iron Piping, piping components, and piping elements exposed to Soil (3.2.1-37)	Loss of material caused by selective leaching	Chapter XI.M33, "Selective Leaching"	No	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.1.1)
Elastomers Elastomer seals and components exposed to Air – indoor, uncontrolled (External) (3.2.1-38)	Hardening and loss of strength caused by elastomer degradation	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.1.1)
Steel Containment isolation piping and components (External surfaces) exposed to Condensation (External) (3.2.1-39)	Loss of material caused by general corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel Ducting, piping, and components (External surfaces), Ducting, closure bolting, Containment isolation piping and components (External surfaces) exposed to Air – indoor, uncontrolled (External) (3.2.1-40)	Loss of material caused by general corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring of Mechanical Components	Consistent with the GALL Report
Steel External surfaces exposed to Air – outdoor (External) (3.2.1-41)	Loss of material caused by general corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring of Mechanical Components	Consistent with the GALL Report
Aluminum Piping, piping components, and piping elements exposed to Air – outdoor (3.2.1-42)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.1.1)
Elastomers Elastomer seals and components exposed to Air – indoor, uncontrolled (Internal) (3.2.1-43)	Hardening and loss of strength caused by elastomer degradation	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.1.1)
Steel Piping and components (Internal surfaces), Ducting and components (Internal surfaces) exposed to Air – indoor, uncontrolled (Internal) (3.2.1-44)	Loss of material caused by general corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report
Steel Encapsulation components exposed to Air – indoor, uncontrolled (Internal) (3.2.1-45)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.1.1)
Steel Piping and components (Internal surfaces) exposed to Condensation (Internal) (3.2.1-46)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.1.1)
Steel Encapsulation components exposed to Air with borated water leakage (Internal) (3.2.1-47)	Loss of material caused by general, pitting, crevice, and boric acid corrosion	Chapter XI.M38, "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 (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel Piping, piping components, and piping elements (Internal surfaces); tanks exposed to Condensation (Internal) (3.2.1-48)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M38, "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 Piping, piping components, and piping elements exposed to Lubricating oil (3.2.1-49)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis and One-Time Inspection	Consistent with the GALL Report
Copper-alloy, stainless steel piping, piping components, and piping elements exposed to lubricating oil (3.2.1-50)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis and One-Time Inspection	Consistent with the GALL Report
Steel, copper alloy, stainless steel heat exchanger tubes exposed to lubricating oil (3.2.1-51)	Reduction of heat transfer caused by fouling	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis and One-Time Inspection	Consistent with the GALL Report
Steel (with coating or wrapping) piping, piping components, and piping elements exposed to soil or concrete (3.2.1-52)	Loss of material caused by general, pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.1.1)
Stainless steel, nickel alloy, piping, piping components, and piping elements exposed to soil or concrete (3.2.1-53)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Buried and Underground Piping and Tanks	Consistent with the GALL Report
Steel; stainless steel, nickel alloy, underground piping, piping components, and piping elements exposed to air-indoor uncontrolled or condensation (external) (3.2.1-53a)	Loss of material caused by general (steel only), pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to treated water >60 °C (>140 °F) (3.2.1-54)	Cracking caused by stress corrosion cracking, intergranular stress corrosion cracking	Chapter XI.M7, "BWR Stress Corrosion Cracking," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to concrete (3.2.1-55)	None	None, provided 1) attributes of the concrete are consistent with ACI 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG-1557, and 2) plant OE indicates no degradation of the concrete	No, if conditions are met.	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.1.1)
Aluminum piping, piping components, and piping elements exposed to air – indoor, uncontrolled (internal/external) (3.2.1-56)	None	None	NA - No AEM or AMP	None	Consistent with the GALL Report
Copper-alloy piping, piping components, and piping elements exposed to air – indoor, uncontrolled (external), gas (3.2.1-57)	None	None	NA - No AEM or AMP	None	Consistent with the GALL Report
Copper-alloy (≤15% Zn and ≤8% Al) piping, piping components, and piping elements exposed to air with borated water leakage (3.2.1-58)	None	None	NA - No AEM or AMP	None	Not applicable to Callaway (see SER Section 3.2.2.1.1)
Galvanized steel Ducting, piping, and components exposed to Air – indoor, controlled (External) (3.2.1-59)	None	None	NA - No AEM or AMP	None	Not applicable to Callaway (see SER Section 3.2.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Glass Piping elements exposed to Air – indoor, uncontrolled (External), Lubricating oil, Raw water, Treated water, Treated water (borated), Air with borated water leakage, Condensation (Internal/External), Gas, Closed-cycle cooling water, Air – outdoor (3.2.1-60)	None	None	NA - No AEM or AMP	None	Not applicable to Callaway (see SER Section 3.2.2.1.1)
Nickel alloy Piping, piping components, and piping elements exposed to Air – indoor, uncontrolled (External) (3.2.1-61)	None	None	NA - No AEM or AMP	None	Not applicable to Callaway (see SER Section 3.2.2.1.1)
Nickel alloy Piping, piping components, and piping elements exposed to Air with borated water leakage (3.2.1-62)	None	None	NA - No AEM or AMP	None	Not applicable to Callaway (see SER Section 3.2.2.1.1)
Stainless steel Piping, piping components, and piping elements exposed to Air – indoor, uncontrolled (External), Air with borated water leakage, Concrete, Gas, Air – indoor, uncontrolled (Internal) (3.2.1-63)	None	None	NA - No AEM or AMP	None	Consistent with the GALL Report
Steel Piping, piping components, and piping elements exposed to Air – indoor, controlled (External), Gas (3.2.1-64)	None	None	NA - No AEM or AMP	None	Consistent with the GALL Report
Any material piping, piping components and piping elements exposed to reactor coolant (3.2.1-65)	Wall thinning due to erosion	Chapter XI.M17, “Flow-Accelerated Corrosion”	No	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Metallic piping, piping components, and tanks exposed to raw water or waste water (3.2.1-66)	Loss of material due to recurring internal corrosion	A plant-specific aging management program is to be evaluated to address recurring internal corrosion	Yes, plant-specific	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.2.9)
Stainless steel or aluminum tanks (within the scope of Chapter XI.M29, "Aboveground Metallic Tanks") exposed to soil or concrete, or the following external environments air-outdoor, air-indoor uncontrolled, moist air, condensation (3.2.1-67)	Cracking due to stress corrosion cracking	Aboveground Metallic Tanks (B2.1.15)	No	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.2.1)
Metallic piping, piping components, heat exchangers, tanks with Service Level III augmented) internal coatings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, or lubricating oil (3.2.1-67a)	Loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage	Chapter XI.M42, "Service Level III (augmented) Coatings Monitoring and Maintenance Program"	No	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.1.1)
Steel, stainless steel, or aluminum tanks (within the scope of Chapter XI.M29, "Aboveground Metallic Tanks") exposed to soil or concrete, or the following external environments air-outdoor, air-indoor uncontrolled, moist air, condensation (3.2.1-68)	Loss of material due to general (steel only), pitting, and crevice corrosion	Chapter XI.M29, "Aboveground Metallic Tanks"	No	Not applicable	Not applicable to Callaway (see SER Section 3.2.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Insulated steel, stainless steel, copper alloy, or aluminum, piping, piping components, and tanks exposed to condensation, air-outdoor (3.2.1-69)	Loss of material due to general (steel, and copper alloy only), pitting, and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components" or Chapter XI.M29, “Aboveground Metallic Tanks,” (for tanks only)	No	External Surfaces Monitoring of Mechanical Components	Consistent with the GALL Report
Steel, stainless steel or aluminum tanks (within the scope of Chapter XI.M29, “Aboveground Metallic Tanks”) exposed to treated water, treated borated water (3.2.1-70)	Loss of material due to general (steel only), pitting and crevice corrosion	Chapter XI.M29, “Aboveground Metallic Tanks”	No	Aboveground Metallic Tanks	Consistent with the GALL Report
Insulated stainless steel, aluminum, or copper alloy (>15% Zn) piping, piping components, and tanks exposed to condensation, air-outdoor (3.2.1-71)	Cracking due to stress corrosion cracking	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components" or Chapter XI.M29, “Aboveground Metallic Tanks,” (for tanks only)	No	External Surfaces Monitoring of Mechanical Components or Aboveground Metallic Tanks	Consistent with the GALL Report

3.2.2.1 AMR Results Consistent with the GALL Report

LRA Section 3.2.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the ESF systems components:

- Aboveground Metallic Tanks
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
- Bolting Integrity
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks
- Closed Treated Water Systems
- External Surfaces Monitoring of Mechanical Components
- Flow-Accelerated Corrosion
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Lubricating Oil Analysis
- One-Time Inspection
- One-Time Inspection of ASME Code Class 1 Small-Bore Piping
- Selective Leaching
- Water Chemistry

LRA Tables 3.2.2-1 through 3.2.2-6 summarize AMRs for the ESFs components and indicate AMRs claimed to be consistent with the GALL Report.

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

The applicant noted for each AMR item how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with notes A–E, indicating how the AMR is consistent with the GALL Report.

Note A indicates that the AMR item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. The staff audited these items to confirm consistency with the GALL Report and validity of the AMR for the site-specific conditions.

Note B indicates that the AMR item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff audited these items to 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, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report; however, the applicant identified in the GALL Report a different component with the same material, environment, aging effect, and AMP as the component under review. The staff audited these items to 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, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff audited these AMR 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 audited 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 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 is discussed below.

3.2.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.2-1, items 3.2.1-17, 3.2.1-26, 3.2.1-38, 3.2.1-43, 3.2.1-46, and 3.2.1-54, 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 that these items are not applicable to Callaway, which is a PWR.

For LRA Table 3.2-1, items 3.2.1-10, 3.2.1-11, 3.2.1-12, 3.2.1-14, 3.2.1-16, 3.2.1-21, 3.2.1-23, 3.2.1-24, 3.2.1-25, 3.2.1-27, 3.2.1-34, 3.2.1-35, 3.2.1-37, 3.2.1-39, 3.2.1-42, 3.2.1-45, 3.2.1-53a, 3.2.1-55, 3.2.1-67, 3.2.1-67a, and 3.2.1-68, the applicant claimed that the corresponding items in the GALL Report are not applicable because the component, material, and environment combination described in the SRP-LR does not exist for in-scope SCs at Callaway. The staff reviewed the LRA and FSAR and confirmed that the applicant's LRA does not have any AMR results applicable for these items.

For LRA Table 3.2-1 items discussed below, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable; however, the staff non-applicability verification of these items required the review of sources beyond the LRA and FSAR, and/or the issuance of RAIs.

LRA Table 3.2-1, item 3.2.1-8 addresses aluminum and copper-alloy (greater than 15 percent zinc or greater than 8 percent aluminum) 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 caused by boric acid corrosion for this component group. In the original LRA, the applicant stated that this item was not applicable; however, in LRA Amendment No. 1 dated April 25, 2012, the applicant revised the LRA to state that the item was applicable and consistent with the GALL Report guidance. The applicant also added AMR items that reference LRA item 3.2.1-8. The staff reviewed the associated AMR items, which cite generic notes A or C, and confirmed the applicant's claim of consistency with the GALL Report.

LRA Table 3.2-1, item 3.2.1-14 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 caused by general corrosion for this component group. The applicant stated that this item is not applicable because closure bolting was evaluated using the plant indoor air environment and SRP-LR Table 3.2-1, item 3.2.1-13 for steel closure bolting exposed to an air-indoor uncontrolled environment. The staff evaluated the applicant's claim and finds it acceptable because the component group is being managed for loss of material by the Bolting Integrity Program, consistent with the GALL Report recommendations.

LRA Table 3.2-1, item 3.2.1-16 addresses steel containment isolation piping and components (internal surfaces), piping, piping components, and piping elements exposed to treated water. The GALL Report recommends GALL Report AMP XI.M2, "Water Chemistry," and XI.M32, "One-Time Inspection," to manage loss of material caused by general, pitting, and crevice corrosion 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 finds it acceptable because the applicant has evaluated steel containment

isolation components with LRA items 3.4.1-13 and 3.4.1-14 and is managing loss of material caused by general, pitting, and crevice corrosion for the subject components with the Water Chemistry and One-Time Inspection Programs, consistent with the GALL Report guidance for LRA item 3.2.1-16.

LRA Table 3.2-1, item 3.2.1-19 addresses stainless steel heat exchanger tubes exposed to treated water, or treated water (borated). The GALL Report recommends AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection," to manage reduction of heat transfer caused by fouling for this component group. The applicant stated that this item is not applicable because Callaway has no in-scope stainless steel heat exchanger tubes exposed to treated water in the containment spray system. In its review of the applicant's claim, the staff noted that although Callaway's containment spray system does not have stainless steel heat exchanger tubes exposed to treated water, this component type with an intended function of heat transfer can be found in the RHR system. The staff noted that LR-ISG-2011-01, "Aging Management of Stainless Steel Structures and Components in Treated Borated Water," discusses the applicability of reduction of heat transfer for components in both treated water and treated borated water. Therefore, the staff required additional information to ensure that the aging effects for this component group were being adequately managed. By letter dated August 16, 2012, the staff issued RAI 3.2.1.19-2 requesting the applicant to justify the non-applicability of this item. In its response dated September 20, 2012, the applicant added item 3.2.1.019 to LRA Table 3.2.2-6 reflecting reduction of heat transfer as an aging effect for the stainless steel heat exchanger tubes in the RHR heat exchangers and the RHR pump seal water coolers. The applicant also revised LRA Table 3.2-1, item 19, as being consistent with the GALL Report. In a letter dated December 19, 2012, the applicant also added reduction of heat transfer as an aging effect for the stainless steel reactor coolant pump thermal barrier cooler in LRA Table 3.1.2-2. The staff finds the applicant's response acceptable because, consistent with SRP-LR A.1.2.1, the applicant's determination of applicable aging effects is now based on those aging effects that potentially could cause component degradation. The staff notes that the applicant's use of the Water Chemistry and One-Time Inspection Programs to manage reduction of heat transfer in the heat exchanger tubes exposed to treated borated water for item 3.2.1-19 is consistent with the GALL Report. The staff's concern described in RAI 3.2.1.19-2 is resolved.

LRA Table 3.2-1, item 3.2.1-38 addresses elastomer seals and components externally exposed to indoor uncontrolled air. The GALL Report recommends GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," to manage hardening and loss of strength caused by elastomer degradation for this component group. The applicant stated that this item is not applicable because it only applies to BWR plants. The staff finds that the applicant's claim acceptable because SRP-LR item 3.2.1-38, which cites GALL Report item V.B.EP-59, is only associated with BWR standby gas treatment systems. The staff confirmed that the applicant is appropriately managing hardening and loss of strength caused by elastomer degradation because the applicant cited item 3.3.1-76 to manage the aging of the flexible connectors in the ESF systems. Both item 3.2.1-38 and 3.3.1-76 state the same material, components, environment, AERM, and AMP.

LRA Table 3.2-1, item 3.2.1-43 addresses elastomer seals and components exposed to internal indoor uncontrolled air. The GALL Report recommends GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to manage hardening and loss of strength caused by elastomer degradation for this component group. The applicant stated that this item is not applicable because it only applies to BWR plants. The staff finds that the applicant's claim acceptable because SRP-LR item 3.2.1-43, which cites GALL Report

item V.B.EP-58, is only associated with BWR standby gas treatment systems. The staff confirmed that the applicant is appropriately managing hardening and loss of strength caused by elastomer degradation because the only applicable in-scope components in the ESF systems are flexible connectors which cite item 3.3.1-76 and use the External Surfaces Monitoring of Mechanical Components Program to manage hardening and loss of strength. The staff noted that the "scope of program" program element of AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," allows for the inspection of internal surfaces of polymeric components when the external and internal surfaces are in the same environment such that the external condition of the component would be representative of the internal surfaces. The applicant's External Surfaces Monitoring of Mechanical Components Program states that it inspects for "hardening/loss of strength as evidenced by loss of suppleness during manual or physical manipulation." The staff also noted that the plant indoor air environment (external surface) and ventilation atmosphere environment (internal) are sufficiently similar in temperature such that the external surfaces would be representative of the internal surfaces.

LRA Table 3.2-1, item 3.2.1-52 addresses steel (with coating or wrapping) piping, piping components, and piping elements exposed to soil or concrete. The SRP-LR recommends GALL Report AMP XI.M41 "Buried and Underground Piping and Tanks" to manage loss of material caused by general, pitting, crevice, and MIC for this component group. The applicant stated that this item is not applicable because the item is only applicable to BWR plants. The staff noted that SRP-LR, item 3.2.1-52 is applicable to both PWR and BWR plants. While the staff does not agree with the applicant's basis for disposition of this item as being not applicable to PWRs, the staff did a search of the FSAR and the piping and instrument drawings submitted with the LRA for steel (with coatings or wrappings) piping, piping components, and piping elements exposed to soil or concrete and based on its review the staff confirmed that this material and environment combination does not exist in the engineered safety features systems. The staff finds it acceptable that the applicant is not using this AMR item because, based on a review of the LRA and FSAR, there are no in-scope steel piping, piping components, and piping elements exposed to soil or concrete in the engineered safety features systems.

LRA Table 3.2-1, item 3.2.1-58 addresses copper-alloy (less than or equal to 15 percent zinc and less than or equal to 8 percent aluminum) piping, piping components, and piping elements exposed to air with borated water leakage. The applicant stated that this item is not applicable because there are no in-scope components associated with this item and that there are no aging effects, aging mechanisms or AMPs for this component group. SRP-LR item 3.2.1-58 recommends that there is no aging effect or aging mechanism and that no AMP is recommended for this component group exposed to this environment and therefore, the staff finds the applicant's determination acceptable.

LRA Table 3.2-1, item 3.2.1-59 addresses galvanized steel ducting, piping, and components exposed to air-indoor, controlled (external) and states that there are no aging effects, aging mechanisms, or AMPs. The applicant stated that the item is not applicable because there are no in-scope components associated with this item. SRP-LR item 3.2.1-59 states that there is no aging effect or aging mechanism and that no AMP is recommended for this component group exposed to this environment; therefore, the staff finds the applicant's determination acceptable.

LRA Table 3.2-1, item 3.2.1-60 addresses glass piping elements exposed to uncontrolled indoor air, lubricating oil, raw water, treated water, treated borated water, air with borated water leakage, condensation, gas, closed-cycle cooling water, and outdoor air. The applicant stated that the item is not applicable because there are no in-scope components associated with this item. SRP-LR item 3.2.1-60 states that there is no aging effect or aging mechanism and that no

AMP is recommended for this component group exposed to these environments; therefore, the staff finds the applicant's determination acceptable.

LRA Table 3.2-1, items 3.2.1-61 and 3.2.1-62, address nickel alloy piping, piping components, and piping elements exposed to (respectively) air-indoor, uncontrolled (external) and air with borated water leakage. The applicant stated that these items are not applicable because there are no in-scope components associated with them. SRP-LR items 3.2.1-61 and 3.2.1-62 both state that there are no respective aging effects or aging mechanisms and that no AMP is recommended for this component group exposed to these environments; therefore, the staff finds the applicant's determination acceptable.

LRA Table 3.2-1, item 3.2.1-65, addresses piping, piping component and piping elements made from any material exposed to treated water and treated borated water. The GALL Report recommends GALL Report AMP XI.M17, "Flow-Accelerated Corrosion," to manage wall thinning due to erosion for this component group. The applicant stated that this item is not applicable because it has not experienced this aging effect in any ESF systems. The staff noted that item 3.2.1-65 was generated as part of LR-ISG-2012-01, "Wall Thinning Due to Erosion Mechanisms," which applies to management of erosion mechanisms that have been identified but where the underlying design issue has not been corrected. The staff evaluated the applicant's claim and finds it acceptable because, during its independent review of the applicant's operating experience database, the staff did not identify any issues with wall thinning due to erosion in any ESF systems at Callaway Unit 1.

3.2.2.1.2 Cracking Due to Stress Corrosion Cracking

LRA Table 3.2-1, item 3.2.1-20 addresses stainless steel pumps, pipes, pipe elements, tanks, and heat exchangers exposed to treated borated water which will be managed for cracking due to SCC. 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 these components with this material and environment combination.

The GALL Report as revised by LR-ISG-2011-01, Revision 1, "Aging Management of Stainless Steel Structures and Components in Treated Borated Water," recommends GALL Report AMP XI.M2, "Water Chemistry," and XI.M32, "One-Time Inspection" Programs to ensure that these aging effects are adequately managed. By letter dated December 19, 2012, the applicant revised the subject AMR items to cite generic notes A or C to reflect the LRA consistency with the revised GALL Report guidance. The staff confirmed the consistency with the GALL Report and, therefore, finds the applicant's proposal to manage aging acceptable.

The staff concludes that for LRA item 3.2.1-20, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2.2.1.3 Loss of Material due to Pitting and Crevice Corrosion

LRA Table 3.2-1, item 3.2.1-22 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, tanks, and heat exchanger components. The GALL Report, as revised by LR-ISG-2011-01, Revision 1, "Aging

Management of Stainless Steel Structures and Components in Treated Borated Water," recommends GALL Report AMPs XI.M2, "Water Chemistry," and XI.M32, "One-Time Inspection," to ensure that these aging effects are adequately managed. By letter dated December 19, 2012, the applicant revised the subject AMR items to cite generic notes A or C to reflect the LRA consistency with the revised GALL Report guidance. The staff confirmed the consistency with the GALL Report and, therefore, finds the applicant's proposal to manage aging acceptable.

The staff concludes that for LRA item 3.2.1-22, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2.2.1.4 No Aging Effects Requiring Management

LRA Table 3.2-1, item 3.2.1-63 addresses stainless steel piping, piping components, and piping elements exposed to air-indoor uncontrolled, air with borated water leakage, concrete, or gas and states that there are no AERM and no AMP is proposed. The GALL Report states that there are no AERM and no AMP is proposed for this component group.

During its review of components associated with item 3.2.1-63, for which the applicant cited generic notes A or C, the staff noted that the LRA states that there are no AERM and no AMP is proposed for stainless steel expansion joints, piping, and tanks exposed internally to borated water leakage in LRA Table 3.2.2-6. However, the GALL Report environment of air with borated water leakage is usually referred to as an external environment. The GALL Report recommends that stainless steel components exposed to treated borated water or condensation be managed for loss of material. It was unclear to the staff how the components exposed internally to borated water leakage are configured such that exposure to borated water leakage can occur, but the leakage does not accumulate such that the environment becomes borated water or condensation. By letter dated August 16, 2012, the staff issued RAI 3.2.1.063-1 requesting that the applicant explain the configuration of the components exposed internally to borated water leakage and how accumulation of the borated water leakage is prevented. If accumulation of borated water leakage can occur, the staff also requested the applicant to explain why the components have no AERM.

In its response dated September 20, 2012, the applicant stated that the components are associated with the RHR lines between the containment sump and the pump suction. The applicant stated that subject components are in a watertight enclosure outside the containment building that houses the system isolation valves and that the enclosure was identified as a tank in the LRA and includes expansion joints and guard pipes. The applicant also stated that the borated water leakage environment was selected because the RHR lines are internally partially filled with borated water. The applicant further stated that the domes on the enclosure are periodically removed for testing of the isolation valves and visual inspection of the enclosure. In addition, the applicant stated that if any signs of borated water leakage are observed, corrective action is taken in accordance with its CAP and Boric Acid Corrosion Program; therefore, preventing accumulation of borated water in the enclosure.

The staff finds the applicant's response acceptable because the stainless steel components are located within an enclosure in which borated water leakage is not expected, which is an environment similar to being externally exposed to borated water leakage, and the components

are managed such that accumulation of borated water leakage would not occur. The staff's concern described in RAI 3.2.1.063-1 is resolved.

The staff concludes that for LRA item 3.2.1-63, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2.2.1.5 Loss of Material Due to General, Pitting, and Crevice Corrosion

LRA Table 3.3-1, item 3.3.1-79 addresses copper-alloy piping, piping components, and piping elements exposed to condensation (external) which will be managed for loss of material due to general, pitting, and crevice corrosion. For the AMR items that cite generic note E in LRA Table 3.2.2-4, the LRA credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effect for heat exchanger components exposed externally to a ventilation atmosphere. The AMR item also cites a plant-specific note that states the subject components are enclosed within another component. 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 periodic visual inspections of the external surfaces of components to manage aging for metallic components.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.12. The staff noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program proposes to manage the aging of metallic components through the use of visual inspections. 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 acceptable because the program includes visual inspections of components which are capable of detecting loss of material and the subject components are located inside other components.

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 function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation is Recommended

In LRA Section 3.2.2.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the ESF components and provides information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to cladding breach
- loss of material due to pitting and crevice corrosion
- loss of material due to erosion
- loss of material due to general corrosion and fouling that leads to corrosion
- cracking due to SCC
- QA for aging management of nonsafety-related components

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 it adequately addressed the issues further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.2.2.2. The staff's review of the applicant's further evaluation follows.

3.2.2.2.1 Cumulative Fatigue Damage

LRA Section 3.2.2.2.1, associated with LRA Table 3.2-1, item 3.2.1-1, addresses steel and stainless steel piping, piping components, and piping elements in the engineered-safety systems and being managed for cumulative fatigue damage. The applicant addressed the further evaluation criteria of the SRP-LR by stating that fatigue is a TLAA, as defined in 10 CFR 54.3, and is required to be evaluated in accordance with 10 CFR 54.21(c). The applicant stated that its evaluation of the TLAA is addressed separately in LRA Section 4.3.

The staff reviewed LRA Section 3.2.2.2.1 against the criteria in SRP-LR Section 3.2.2.2.1 which states that cumulative fatigue damage of steel and stainless steel piping, piping components, and piping elements in the emergency core cooling (ECC) systems is a TLAA, and that these TLAAs are to be evaluated in accordance with the TLAA acceptance criteria requirements of 10 CFR 54.21(c). The staff reviewed the applicant's AMR items and determined that the AMR results are consistent with the recommendations of the GALL Report and SRP-LR, for managing cumulative fatigue damage in steel and stainless steel piping, piping components, and piping elements.

Based on its review, the staff concludes that the applicant has met the SRP-LR Section 3.2.2.2.1 criteria. For those items that apply to LRA Section 3.2.2.2.1, the staff determined that the LRA is consistent with the GALL Report and 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). SER Section 4.3 documents the staff's review of the applicant's evaluation of the TLAA for these components.

3.2.2.2.2 Loss of Material Due to Cladding Breach

LRA Section 3.2.2.2.2, associated with LRA Table 3.2-1, item 3.2.1-2, addresses loss of material due to cladding breach in steel with stainless steel cladding pump casings exposed to treated borated water. The applicant stated that this item is not applicable because there are no in-scope steel with stainless steel cladding pump casings exposed to treated borated water in the ECC system. The staff reviewed LRA Sections 2.3.2 and 3.2, and FSAR Section 6.0 SP, Table 6.1-1 and finds that no in-scope steel with stainless steel cladding pump casings 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

The staff reviewed LRA Section 3.2.2.2.3 against the following criteria in SRP-LR Section 3.2.2.2.3:

(1) LRA Section 3.2.2.2.3.1, associated with LRA Table 3.2-1, item 3.2.1-3, addresses loss of material due to pitting and crevice corrosion in stainless steel, partially-encased tanks with breached moisture barrier exposed to raw water. The applicant stated that this item is not applicable because it has no in-scope stainless steel tanks exposed to raw water

in the ECC system. The staff reviewed LRA Sections 2.3.2 and 3.2, and the FSAR and finds that no in-scope stainless steel, partially-encased tanks with breached moisture barrier exposed to raw water are present in the ESF systems.

(2) LRA Section 3.2.2.2.3.2, associated with LRA Table 3.2-1, item 3.2.1-4, and as amended by letter dated December 20, 2013, addresses stainless steel piping, piping components, and piping elements exposed to outdoor air, which will be managed for loss of material by the External Surfaces Monitoring of Mechanical Components Program. The criteria in SRP-LR Section 3.2.2.2.3, item 2, 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 outdoor air. The SRP-LR also states that GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," is an acceptable method to manage this aging effect. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the External Surfaces Monitoring of Mechanical Components Program manages loss of material from pitting and crevice corrosion for stainless steel external surfaces exposed to the outdoor air environment.

The staff's evaluation of the applicant's External Surfaces Monitoring of Mechanical Components Program is documented in SER Section 3.0.3.1.10. In its review of components associated with item 3.2.1-4 for which the applicant credited the External Surfaces Monitoring of Mechanical Components Program to manage aging, 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 of Mechanical Components Program is acceptable because: (a) the program includes periodic visual inspections that will occur at least every RFO, which are capable of detecting loss of material; and (b) the inspection technique and frequency are consistent with the GALL Report.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.2.2.2.3, item 2 criteria. For those items associated with LRA Section 3.2.2.2.3.2, 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 function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.4 Loss of Material Due to Erosion

LRA Section 3.2.2.2.4, associated with LRA Table 3.2-1, item 3.2.1-5, addresses stainless steel minimum flow orifices exposed to treated borated water, which will be managed for loss of material due to erosion by the Water Chemistry and One-Time Inspection Programs. The criterion in SRP-LR Section 3.2.2.2.4 states that a plant-specific AMP should be evaluated for erosion of the orifice caused by extended use of the centrifugal high-pressure safety injection pump for normal charging. The staff noted that the erosion issue was based on the length of time that the orifice experiences flow and was not based on any chemistry control concern. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the AMPs used to manage the aging include the Water Chemistry and One-Time Inspection Programs.

In its review of components associated with item 3.2.1-5, the staff noted that the GALL Report credits AMP XI.M2 "Water Chemistry," for managing loss of material due to corrosion in stainless steel components exposed to treated borated water. However, the GALL Report does not credit AMP XI.M2 for managing loss of material due to erosion, and consequently, it was not clear to the staff how the combination of the Water Chemistry and One-Time Inspection

Programs could effectively manage this aging effect for the minimum flow orifice. Therefore, by letter dated August 6, 2012, the staff issued RAI 3.2.2.2.4-1 requesting the applicant to clarify how the Water Chemistry and One-Time Inspection Programs manage loss of material caused by erosion of the minimum flow orifice in the high pressure safety injection system.

In its response dated September 6, 2012, the applicant stated that erosion is not an applicable aging effect for the associated minimum flow orifices because the centrifugal high pressure charging pumps are not used for normal charging at Callaway. The applicant also stated that normal charging is provided by the normal charging pump and that check valves in the system prevent normal charging flow from going through the high pressure safety injection pump minimum flow recirculation orifices. Based on this information, the applicant revised LRA Section 3.2.2.2.4 and Table 3.2-1, item 3.2.1-5 to state that erosion of the minimum flow orifices for the high pressure safety injection pumps is not applicable to Callaway. The staff finds the applicant's response acceptable because it provided sufficient bases to conclude that the aging effect addressed by this further evaluation item does not apply to Callaway. The staff's concern described in RAI 3.2.2.2.4-1 is resolved.

3.2.2.2.5 Loss of Material Due to General Corrosion and Fouling that Leads to Corrosion

LRA Section 3.2.2.2.5, associated with LRA Table 3.2-1, item 3.2.1-6, addresses loss of material due to general corrosion and fouling that leads to corrosion in steel drywell and suppression chamber spray system nozzle and flow orifice internal surfaces exposed to air-indoor uncontrolled. The applicant stated that this item is not applicable because loss of material for these BWR components is only applicable to BWR plants. The staff noted that this item is associated only with BWRs and, therefore, finds the applicant's claim acceptable.

3.2.2.2.6 Cracking Due to Stress Corrosion Cracking

LRA Section 3.2.2.2.6, associated with LRA Table 3.2-1, item 3.2.1-7, and as amended by letter dated December 20, 2013, addresses stainless steel piping, piping components, and piping elements exposed to outdoor air, which will be managed for SCC by the External Surfaces Monitoring of Mechanical Components Program. The criteria in SRP-LR Section 3.2.2.2.6 states that SCC could occur for stainless steel piping, piping components, piping elements, and tanks exposed to outdoor air. The SRP-LR also states that GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," is an acceptable method to manage this aging effect. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the External Surfaces Monitoring of Mechanical Components Program manages SCC for stainless steel external surfaces exposed to outdoor environment.

The staff's evaluation of the applicant's External Surfaces Monitoring of Mechanical Components Program is documented in SER Section 3.0.3.1.10. In its review of components associated with item 3.2.1-7 for which the applicant credited the External Surfaces Monitoring of Mechanical Components Program to manage aging, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal is acceptable because: (a) the program includes periodic visual inspections that will occur at least every RFO, which are capable of detecting SCC; and (b) the inspection technique and frequency are consistent with the GALL Report.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.2.2.2.6 criteria. For those items associated with LRA Section 3.2.2.2.6, 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

function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.7 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA Program.

3.2.2.2.8 Operating Experience

SER Section 3.0.5, "Operating Experience for Aging Management Programs," documents the staff's evaluation of the applicant's consideration of operating experience of aging management programs.

3.2.2.2.9 Loss of Material due to Recurring Internal Corrosion

LRA Section 3.2.2.2.9, as modified through LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion under Insulation," is associated with LRA Table 3.2-1, item 3.2.1-66, and addresses loss of material due to recurring internal corrosion in metallic piping, piping components, and tanks exposed to raw water or waste water. By letter dated October 7, 2013, the staff issued RAI 3.0.3-1 requesting the applicant to address issues related to recurring internal corrosion that are addressed by the new SRP-LR Section 3.2.2.2.9. In its response dated December 20, 2013, the applicant stated that this item is not applicable because operating experience associated with ESF systems does not meet the threshold for significance or frequency of occurrence of the aging effect to be considered as recurring internal corrosion.

The staff evaluated the applicant's claim and finds it acceptable because the applicant's reviews of past operating experience did not identify instances of recurring internal corrosion in ESF systems. The staff notes that its independent search of plant-specific operating experience during the AMP audit did not identify instances that warranted augmenting any AMPs that manage components in ESF systems to address internal corrosion.

3.2.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.2.2-1 through 3.2.2-6, the staff reviewed additional details of the AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.2.2-1 through 3.2.2-6, the applicant indicated, via notes F through J, that the combination of component type, material, environment, and AERM does not correspond to an AMR 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 AMR item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the AMR item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant has

demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

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 identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the containment spray system component groups are consistent with the GALL Report.

3.2.2.3.2 Engineered Safety Features—Summary of Aging Management Evaluation—Containment Integrated Leak Rate Testing 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 containment integrated leak rate testing system component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the containment integrated leak rate testing system component groups are consistent with the GALL Report.

3.2.2.3.3 Engineered Safety Features—Summary of Aging Management Evaluation—Containment Hydrogen Control System—LRA Table 3.2.2-3

The staff reviewed LRA Table 3.2.2-3, which summarizes the results of AMR evaluations for the containment hydrogen control system component groups.

Stainless Steel Piping Exposed to Plant Indoor Air. In LRA Table 3.2.2-3, the applicant stated there is a TLAA for stainless steel piping exposed to plant indoor air which cite generic note H. The staff confirmed that there is a TLAA, as documented in LRA Section 4.3.5, for this component and material. The staff's evaluation of the fatigue TLAA for ANSI B31.1 and ASME Code Section III Class 2 and 3 piping is documented in SER Section 4.3.5.2.

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

3.2.2.3.4 Engineered Safety Features—Summary of Aging Management Evaluation—Containment Purge 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 containment purge system component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the containment purge system component groups are consistent with the GALL Report.

3.2.2.3.5 Engineered Safety Features—Summary of Aging Management Evaluation—High Pressure Coolant Injection System—LRA Table 3.2.2-5

The staff reviewed LRA Table 3.2.2-5, which summarizes the results of AMR evaluations for the high pressure coolant injection system component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the high pressure coolant injection system component groups are consistent with the GALL Report.

3.2.2.3.6 Engineered Safety Features—Summary of Aging Management Evaluation—Residual Heat Removal System—LRA Table 3.2.2-6

The staff reviewed LRA Table 3.2.2-6, which summarizes the results of AMR evaluations for the RHR system component groups.

Stainless Steel Heat Exchangers Exposed to Treated Borated Water and Carbon Steel Heat Exchangers Exposed to Closed Cycle Cooling Water. In LRA Table 3.2.2-6, the applicant stated there is a TLAA for stainless steel heat exchangers exposed to treated borated water and carbon steel heat exchangers exposed to closed cycle cooling water which cite generic note H. The staff confirmed that there is a TLAA, as documented in LRA Section 4.3.8, for this component and material. The staff's evaluation of the fatigue TLAA for ASME Code Class 2 heat exchangers is documented in SER Section 4.3.8.2.

Calcium Silicate Insulation Exposed to Plant Indoor Air. In LRA Table 3.2.2-6, as amended by letter dated December 19, 2012, the applicant stated that for calcium silicate insulation exposed to plant indoor air, there is no aging effect and no AMP is proposed. The AMR item cited generic note J, indicating that neither the component nor the material and environment are evaluated in the GALL Report.

The staff noted that, subsequent to the applicant's December 19, 2012, LRA amendment, License Renewal Interim Staff Guidance (LR-ISG) LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," was issued, adding SRP-LR item 3.4.1-64 to manage reduced thermal insulation resistance for calcium silicate insulation exposed to plant air using GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components." In LRA Amendment 28, dated December 20, 2013, the applicant revised this item to manage reduced thermal insulation resistance with the External Surfaces Monitoring of Mechanical Components Program, consistent with LR-ISG-2012-02. Therefore, the staff finds the applicant's proposal to manage aging acceptable.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations as discussed here. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.3 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 function(s) will be

maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3 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 storage and handling system
- fuel pool cooling and cleanup system
- cranes, hoists, and elevators
- ESW system
- service water system
- reactor makeup water system
- component cooling water (CCW) system
- compressed air system
- nuclear sampling system
- CVC system
- control building HVAC system
- ESW pumphouse HVAC system
- auxiliary building HVAC system
- fuel building HVAC system
- miscellaneous buildings HVAC system
- diesel generator building HVAC system
- turbine building HVAC system
- containment cooling system
- fire protection system
- emergency diesel engine fuel oil storage and transfer system
- standby diesel generator engine system
- EOF and TSC diesels, security building system
- liquid radwaste system
- decontamination system
- oily waste system
- floor and equipment drainage system
- miscellaneous systems in scope ONLY for Criterion 10 CFR 54.4(a)(2)
- circulating water system

3.3.1 Summary of Technical Information in the Application

LRA Section 3.3 provides AMR results for the auxiliary systems components and component groups. LRA Table 3.3-1, "Summary of Aging Management Programs 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 auxiliary systems components and component groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.3.2 Staff Evaluation

The staff reviewed LRA Section 3.3 to determine if the applicant provided sufficient information to demonstrate that the effects of aging for auxiliary systems components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will 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 of AMPs to ensure the applicant's claim that certain AMPs were consistent with the GALL Report. The purpose of this audit was to examine the applicant's AMPs and related documentation and to confirm the applicant's claim of consistency with the corresponding GALL Report AMPs. The staff did not repeat its review of the matters described in the GALL Report. The staff's evaluations of the AMPs are documented in SER Section 3.0.3.

The staff reviewed the AMRs to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did confirm that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. Details of the staff's evaluation are discussed in SER Section 3.3.2.1.

During its review, the staff also selected AMRs consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations are consistent with the SRP-LR Section 3.3.2.2 acceptance criteria. The staff's evaluations are documented in SER Section 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.

The staff's review of the auxiliary systems component groups followed several approaches. One approach, documented in SER Section 3.3.2.1, discusses the staff's review of AMR results for components 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 systems components is documented in SER Section 3.0.3.

Table 3.3-1 Staff Evaluation for Auxiliary Systems Components in the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	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 caused by fatigue	Fatigue is a time-limited aging analysis (TLAA) to be evaluated for the period of extended operation for structural girders of cranes that fall within the scope of 10 CFR 54 (see SRP, Section 4.7, "Other Plant-Specific TLAAs," for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1))	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.3.2.2.1)
Stainless steel, Steel Heat exchanger components and tubes, Piping, piping components, and piping elements exposed to Treated borated water, Air - indoor, uncontrolled, Treated water (3.3.1-2)	Cumulative fatigue damage caused by fatigue	Fatigue is a time-limited aging analysis (TLAA) to be evaluated for the period of extended operation (see SRP, Section 4.3 "Metal Fatigue," for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1)).	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.3.2.2.1)
Stainless steel Heat exchanger components, non-regenerative exposed to Treated borated water >60 °C (>140 °F) (3.3.1-3)	Cracking caused by stress corrosion cracking; cyclic loading	Chapter XI.M2, "Water Chemistry" The AMP is to be augmented by confirming the absence of cracking caused by stress corrosion cracking and cyclic loading. An acceptable verification program is to include temperature and radioactivity monitoring of the shell side water, and eddy current testing of tubes.	Yes	Water Chemistry and One-Time Inspection	Consistent with the GALL Report (see SER Section 3.3.2.2.2)
Stainless steel Piping, piping components, and piping elements; tanks exposed to Air – outdoor (3.3.1-4)	Cracking caused by stress corrosion cracking	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.2.3)
Steel (with stainless steel or nickel-alloy cladding) Pump Casings exposed to Treated borated water (3.3.1-5)	Loss of material caused by cladding breach	A plant-specific aging management program is to be evaluated. Reference NRC Information Notice 94-63, "Boric Acid Corrosion of Charging Pump Casings Caused by Cladding Cracks."	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.2.3)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel piping, piping components, and piping elements; tanks exposed to air–outdoor (3.3.1-6)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.2.5)
Stainless steel high-pressure pump, casing exposed to treated borated water (3.3.1-7)	Cracking caused by cyclic loading	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	ASME Section XI Inservice Inspection, Subsections I WB, IWC, and IWD	Consistent with the GALL Report
Stainless steel heat exchanger components and tubes exposed to treated borated water >60 °C (>140 °F) (3.3.1-8)	Cracking caused by cyclic loading	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	ASME Section XI Inservice Inspection, Subsections I WB, IWC, and IWD	Consistent with the GALL Report
Steel, aluminum, copper-alloy (>15% Zn or >8% Al) external surfaces, piping, piping components, and piping elements, bolting exposed to air with borated water leakage (3.3.1-9)	Loss of material caused by boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion"	No	Boric Acid Corrosion	Consistent with the GALL Report
Steel, high-strength closure bolting exposed to air with steam or water leakage (3.3.1-10)	Cracking caused by stress corrosion cracking; cyclic loading	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)
Steel, high-strength high-pressure pump, closure bolting exposed to air with steam or water leakage (3.3.1-11)	Cracking caused by stress corrosion cracking; cyclic loading	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)
Steel; stainless steel Closure bolting, Bolting exposed to Condensation, Air – indoor, uncontrolled (External), Air – outdoor (External) (3.3.1-12)	Loss of material caused by general (steel only), pitting, and crevice corrosion	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity	Consistent with the GALL Report
Steel Closure bolting exposed to Air with steam or water leakage (3.3.1-13)	Loss of material caused by general corrosion	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel, Stainless Steel Bolting exposed to Soil (3.3.1-14)	Loss of preload	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity	Consistent with the GALL Report
Steel; stainless steel, copper alloy, nickel alloy, stainless steel closure bolting, bolting exposed to air – indoor, uncontrolled (external), any environment, air – outdoor (external), raw water, treated borated water, fuel oil, treated water (3.3.1-15)	Loss of preload caused by thermal effects, gasket creep, and self-loosening	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to treated water >60 °C (>140 °F) (3.3.1-16)	Cracking caused by stress corrosion cracking, intergranular stress corrosion cracking	Chapter XI.M2, "Water Chemistry," and Chapter XI.M25, "BWR Reactor Water Cleanup System"	No	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.1.1)
Stainless steel heat exchanger tubes exposed to treated water, Treated borated water (3.3.1-17)	Reduction of heat transfer caused by fouling	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report (see SER Section 3.3.2.1.1)
Stainless steel high-pressure pump, casing, piping, piping components, and piping elements exposed to treated borated water >60 °C (>140 °F), sodium pentaborate solution >60 °C (>140 °F) (3.3.1-18)	Cracking caused by stress corrosion cracking	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report
Stainless steel regenerative heat exchanger components exposed to treated water >60 °C (>140 °F) (3.3.1-19)	Cracking caused by stress corrosion cracking	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, stainless steel; steel with stainless steel cladding heat exchanger components exposed to treated borated water >60 °C (>140 °F), treated water >60 °C (>140 °F) (3.3.1-20)	Cracking caused by stress corrosion cracking	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to treated water (3.3.1-21)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.1.1)
Copper-alloy piping, piping components, and piping elements exposed to treated water (3.3.1-22)	Loss of material caused by general, pitting, crevice, and galvanic corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.1.1)
Aluminum piping, piping components, and piping elements exposed to treated water (3.3.1-23)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)
Aluminum piping, piping components, and piping elements exposed to treated water (3.3.1-24)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.1.1)
Stainless steel, stainless steel; steel with stainless steel cladding, aluminum piping, piping components, and piping elements, heat exchanger components exposed to treated water, sodium pentaborate solution (3.3.1-25)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.1.1)
Steel (with elastomer lining), steel (with elastomer lining or stainless steel cladding) piping, piping components, and piping elements exposed to treated water (3.3.1-26)	Loss of material caused by pitting and crevice corrosion (only for steel after lining/cladding degradation)	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel heat exchanger tubes exposed to treated water (3.3.1-27)	Reduction of heat transfer caused by fouling	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.1.1)
Stainless steel, Piping, piping components, and piping elements; tanks exposed to treated borated water (Primary, oxygen levels controlled) >60 °C (>140 °F) (3.3.1-28)	Cracking caused by stress corrosion cracking	Chapter XI.M2, "Water Chemistry"	No	Water Chemistry	Consistent with the GALL Report (see SER Section 3.3.2.1.2)
Steel (with stainless steel cladding); stainless steel piping, piping components, and piping elements exposed to treated borated water (Primary, oxygen levels controlled) (3.3.1-29)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry"	No	Water Chemistry	Consistent with the GALL Report (see SER Section 3.3.2.1.3)
Concrete; cementitious material piping, piping components, and piping elements exposed to raw Water (3.3.1-30)	Changes in material properties caused by aggressive chemical attack	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)
Fiberglass, HDPE Piping, piping components, and piping elements exposed to raw water (internal) 3.3.1-30a)	Cracking, blistering, change in color caused by water absorption	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Open-Cycle Cooling Water System	Consistent with the GALL Report
Concrete; cementitious material piping, piping components, and piping elements exposed to raw water (3.3.1-31)	Cracking caused by settling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Reinforced concrete, asbestos cement piping, piping components, and piping elements exposed to raw water (3.3.1-32)	Cracking caused by aggressive chemical attack and leaching; changes in material properties caused by aggressive chemical attack	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	External Surfaces Monitoring	Consistent with the GALL Report (see SER Section 3.3.2.1.4)
Elastomer seals and components exposed to raw water (3.3.1-32a)	Hardening and loss of strength caused by elastomer degradation; loss of material caused by erosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.3.2.1.18)
Concrete; cementitious material piping, piping components, and piping elements exposed to raw water (3.3.1-33)	Loss of material caused by abrasion, cavitation, aggressive chemical attack, and leaching	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)
Nickel alloy, Copper-alloy piping, piping components, and piping elements exposed to raw water (3.3.1-34)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)
Copper-alloy piping, piping components, and piping elements exposed to raw water (3.3.1-35)	Loss of material caused by general, pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Open-Cycle Cooling Water System	Consistent with the GALL Report
Copper-alloy piping, piping components, and piping elements exposed to raw water (3.3.1-36)	Loss of material caused by general, pitting, crevice, and microbiologically -influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.3.2.1.5)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel (with coating or lining) piping, piping components, and piping elements exposed to raw water (3.3.1-37)	Loss of material caused by general, pitting, crevice, and microbiologically -influenced corrosion; fouling that leads to corrosion; lining/coating degradation	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components or Fire Water System	Consistent with the GALL Report (see SER Section 3.3.2.1.5)
Copper alloy, steel heat exchanger components exposed to raw water (3.3.1-38)	Loss of material caused by general, pitting, crevice, galvanic, and microbiologically -influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Open-Cycle Cooling Water System	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to raw water (3.3.1-39)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to raw water (3.3.1-40)	Loss of material caused by pitting and crevice corrosion; fouling that leads to corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Bolting Integrity	Consistent with the GALL Report (see SER Section 3.3.2.1.5)
Stainless steel piping, piping components, and piping elements exposed to raw water (3.3.1-41)	Loss of material caused by pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Open-Cycle Cooling Water System	Consistent with the GALL Report
Copper alloy, titanium, stainless steel heat exchanger tubes exposed to raw water (3.3.1-42)	Reduction of heat transfer caused by fouling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Open-Cycle Cooling Water System	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water >60 °C (>140 °F) (3.3.1-43)	Cracking caused by stress corrosion cracking	Chapter XI.M21A, "Closed Treated Water Systems"	No	Closed Treated Water System	Consistent with the GALL Report
Stainless steel; steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water >60 °C (>140 °F) (3.3.1-44)	Cracking caused by stress corrosion cracking	Chapter XI.M21A, "Closed Treated Water Systems"	No	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.1.1)
Steel piping, piping components, and piping elements; tanks exposed to closed-cycle cooling water (3.3.1-45)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Closed Treated Water System	Consistent with the GALL Report
Steel, copper alloy heat exchanger components, piping, piping components, and piping elements exposed to closed-cycle cooling water (3.3.1-46)	Loss of material caused by general, pitting, crevice, and galvanic corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Closed Treated Water System	Consistent with the GALL Report
Stainless steel; steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water (3.3.1-47)	Loss of material caused by microbiologically -influenced corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.1.1)
Aluminum piping, piping components, and piping elements exposed to closed-cycle cooling water (3.3.1-48)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water (3.3.1-49)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Closed Treated Water System	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, copper alloy, steel heat exchanger tubes exposed to closed-cycle cooling water (3.3.1-50)	Reduction of heat transfer caused by fouling	Chapter XI.M21A, "Closed Treated Water Systems"	No	Closed Treated Water System	Consistent with the GALL Report
Boraflex Spent fuel storage racks: neutron-absorbing sheets (PWR), spent fuel storage racks: neutron-absorbing sheets (BWR) exposed to treated borated water, treated water (3.3.1-51)	Reduction of neutron-absorbing capacity caused by boraflex degradation	Chapter XI.M22, "Boraflex Monitoring"	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)
Steel cranes: rails and structural girders exposed to air – indoor, uncontrolled (external) (3.3.1-52)	Loss of material caused by general corrosion	Chapter XI.M23, "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) (3.3.1-53)	Loss of material caused by wear	Chapter XI.M23, "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
Copper-alloy piping, piping components, and piping elements exposed to condensation (3.3.1-54)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M24, "Compressed Air Monitoring"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.3.2.1.6)
Steel piping, piping components, and piping elements: compressed air system exposed to condensation (Internal) (3.3.1-55)	Loss of material caused by general and pitting corrosion	Chapter XI.M24, "Compressed Air Monitoring"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.3.2.1.6)
Stainless steel piping, piping components, and piping elements exposed to condensation (Internal) (3.3.1-56)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M24, "Compressed Air Monitoring"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.3.2.1.6)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Elastomers fire barrier penetration seals exposed to air - indoor, uncontrolled, air – outdoor (3.3.1-57)	Increased hardness; shrinkage; loss of strength caused by weathering	Chapter XI.M26, “Fire Protection”	No	Fire Protection	Consistent with the GALL Report
Steel halon/carbon dioxide fire suppression system piping, piping components, and piping elements exposed to air – indoor, uncontrolled (external) (3.3.1-58)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M26, “Fire Protection”	No	Fire Protection	Consistent with the GALL Report
Steel fire rated doors exposed to air - indoor, uncontrolled, air – outdoor (3.3.1-59)	Loss of material caused by wear	Chapter XI.M26, “Fire Protection”	No	Fire Protection	Consistent with the GALL Report
Reinforced concrete structural fire barriers: walls, ceilings and floors exposed to air - indoor, uncontrolled (3.3.1-60)	Concrete cracking and spalling caused by aggressive chemical attack, and reaction with aggregates	Chapter XI.M26, “Fire Protection,” and Chapter XI.S6, “Structures Monitoring”	No	Fire Protection and Structures Monitoring	Consistent with the GALL Report
Reinforced concrete Structural fire barriers: walls, ceilings and floors exposed to Air – outdoor (3.3.1-61)	Cracking, loss of material caused by freeze-thaw, aggressive chemical attack, and reaction with aggregates	Chapter XI.M26, “Fire Protection,” and Chapter XI.S6, “Structures Monitoring”	No	Fire Protection and Structures Monitoring	Consistent with the GALL Report
Reinforced concrete Structural fire barriers: walls, ceilings and floors exposed to Air - indoor, uncontrolled, Air – outdoor (3.3.1-62)	Loss of material caused by corrosion of embedded steel	Chapter XI.M26, “Fire Protection,” and Chapter XI.S6, “Structures Monitoring”	No	Fire Protection and Structures Monitoring	Consistent with the GALL Report
Steel Fire Hydrants exposed to Air – outdoor (3.3.1-63)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M27, “Fire Water System”	No	Fire Water System	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel, Copper-alloy Piping, piping components, and piping elements exposed to Raw water (3.3.1-64)	Loss of material caused by general, pitting, crevice, and microbiologically -influenced corrosion; fouling that leads to corrosion; flow blockage due to fouling	Chapter XI.M27, “Fire Water System”	No	Fire Water System	Consistent with the GALL Report (see SER Section 3.3.2.1.20)
Aluminum Piping, piping components, and piping elements exposed to Raw water (3.3.1-65)	Loss of material caused by pitting and crevice corrosion, fouling that leads to corrosion; flow blockage due to fouling	Chapter XI.M27, “Fire Water System”	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)
Stainless steel Piping, piping components, and piping elements exposed to Raw water (3.3.1-66)	Loss of material caused by pitting and crevice corrosion; fouling that leads to corrosion; flow blockage due to fouling	Chapter XI.M27, “Fire Water System”	No	Fire Water System	Consistent with the GALL Report
Steel Tanks exposed to Air – outdoor (External) (3.3.1-67)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M29, “Aboveground Metallic Tanks”	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)
Steel Piping, piping components, and piping elements exposed to Fuel oil (3.3.1-68)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M30, “Fuel Oil Chemistry”, and Chapter XI.M32, “One-Time Inspection”	No	Fuel Oil Chemistry and One-Time Inspection	Consistent with the GALL Report
Copper-alloy Piping, piping components, and piping elements exposed to Fuel oil (3.3.1-69)	Loss of material caused by general, pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M30, “Fuel Oil Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	Fuel Oil Chemistry and One-Time Inspection	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel Piping, piping components, and piping elements; tanks exposed to Fuel oil (3.3.1-70)	Loss of material caused by general, pitting, crevice, and microbiologically -influenced corrosion; fouling that leads to corrosion	Chapter XI.M30, "Fuel Oil Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Fuel Oil Chemistry and One-Time Inspection	Consistent with the GALL Report
Stainless steel, Aluminum Piping, piping components, and piping elements exposed to Fuel oil (3.3.1-71)	Loss of material caused by pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M30, "Fuel Oil Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Bolting Integrity	Consistent with the GALL Report (see SER Section 3.3.2.1.4)
Gray cast iron, Copper-alloy (>15% Zn or >8% Al) Piping, piping components, and piping elements, Heat exchanger components exposed to Treated water, Closed-cycle cooling water, Soil, Raw water, Waste water (3.3.1-72)	Loss of material caused by selective leaching	Chapter XI.M33, "Selective Leaching"	No	Selective Leaching	Consistent with the GALL Report
Concrete; cementitious material Piping, piping components, and piping elements exposed to Air – outdoor (3.3.1-73)	Changes in material properties caused by aggressive chemical attack	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)
Concrete; cementitious material Piping, piping components, and piping elements exposed to Air – outdoor (3.3.1-74)	Cracking caused by settling	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)
Reinforced concrete, asbestos cement Piping, piping components, and piping elements exposed to Air – outdoor (3.3.1-75)	Cracking caused by aggressive chemical attack and leaching; Changes in material properties caused by aggressive chemical attack	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Elastomers Elastomer: seals and components exposed to Air – indoor, uncontrolled (Internal/External) (3.3.1-76)	Hardening and loss of strength caused by elastomer degradation	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring of Mechanical Components	Consistent with GALL Report (see SER Section 3.3.2.1.7)
Concrete; cementitious material Piping, piping components, and piping elements exposed to Air – outdoor (3.3.1-77)	Loss of material caused by abrasion, cavitation, aggressive chemical attack, and leaching	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)
Steel Piping and components (External surfaces), Ducting and components (External surfaces), Ducting; closure bolting exposed to Air – indoor, uncontrolled (External), Air – indoor, uncontrolled (External), Air – outdoor (External), Condensation (External) (3.3.1-78)	Loss of material caused by general corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.3.2.1.8)
Copper-alloy Piping, piping components, and piping elements exposed to Condensation (External) (3.3.1-79)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report (see SER Section 3.3.2.1.9)
Steel Heat exchanger components, Piping, piping components, and piping elements exposed to Air – indoor, uncontrolled (External), Air – outdoor (External) (3.3.1-80)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring of Mechanical Components	Consistent with the GALL Report
Copper-alloy, Aluminum Piping, piping components, and piping elements exposed to Air – outdoor (External), Air – outdoor (3.3.1-81)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring of Mechanical Components	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Elastomers Elastomer: seals and components exposed to Air – indoor, uncontrolled (External) (3.3.1-82)	Loss of material caused by wear	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring of Mechanical Components	Consistent with GALL Report (see SER Section 3.3.2.1.10)
Stainless steel Diesel engine exhaust piping, piping components, and piping elements exposed to Diesel exhaust (3.3.1-83)	Cracking caused by stress corrosion cracking	Chapter XI.M38, "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
Elastomers Elastomer seals and components exposed to Closed-cycle cooling water (3.3.1-85)	Hardening and loss of strength caused by elastomer degradation	Chapter XI.M38, "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
Elastomers, linings, Elastomer: seals and components exposed to Treated borated water, Treated water, Raw water (3.3.1-86)	Hardening and loss of strength caused by elastomer degradation	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)
Steel; stainless steel Piping, piping components, and piping elements, Piping, piping components, and piping elements, diesel engine exhaust exposed to Raw water (potable), Diesel exhaust (3.3.1-88)	Loss of material caused by general (steel only), pitting, and crevice corrosion	Chapter XI.M38, "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, Copper-alloy Piping, piping components, and piping elements exposed to Moist air or condensation (Internal) (3.3.1-89)	Loss of material caused by general, pitting, and crevice corrosion	For fire water system components: Chapter XI.M27, "Fire Water System." For other components: Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components or Fire Water System	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel Ducting and components (Internal surfaces) exposed to Condensation (Internal) (3.3.1-90)	Loss of material caused by general, pitting, crevice, and (for drip pans and drain lines) microbiologically -influenced corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Fire Protection	Consistent with GALL Report (see SER Section 3.3.2.1.11)
Steel Piping, piping components, and piping elements; tanks exposed to Waste Water (3.3.1-91)	Loss of material caused by general, pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report
Aluminum Piping, piping components, and piping elements exposed to Condensation (Internal) (3.3.1-92)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.3.2.1.12)
Copper-alloy Piping, piping components, and piping elements exposed to Raw water (potable) (3.3.1-93)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M38, "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
Stainless steel Ducting and components exposed to Condensation (3.3.1-94)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.3.2.1.12)
Copper-alloy, Stainless steel, Nickel alloy, Steel Piping, piping components, and piping elements, Heat exchanger components, Piping, piping components, and piping elements; tanks exposed to Waste water, Condensation (Internal) (3.3.1-95)	Loss of material caused by pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Elastomers Elastomer: seals and components exposed to Air – indoor, uncontrolled (Internal) (3.3.1-96)	Loss of material caused by wear	Chapter XI.M38, "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 Piping, piping components, and piping elements, Reactor coolant pump oil collection system: tanks, Reactor coolant pump oil collection system: piping, tubing, valve bodies exposed to Lubricating oil (3.3.1-97)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report (see SER Section 3.3.2.1.13)
Steel Heat exchanger components exposed to Lubricating oil (3.3.1-98)	Loss of material caused by general, pitting, crevice, and microbiologically -influenced corrosion; fouling that leads to corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis and One-Time Inspection	Consistent with the GALL Report
Copper-alloy, Aluminum Piping, piping components, and piping elements exposed to Lubricating oil (3.3.1-99)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis and One-Time Inspection	Consistent with the GALL Report
Stainless steel Piping, piping components, and piping elements exposed to Lubricating oil (3.3.1-100)	Loss of material caused by pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with GALL Report (see SER Section 3.3.2.1.14)
Aluminum Heat exchanger tubes exposed to Lubricating oil (3.3.1-101)	Reduction of heat transfer caused by fouling	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Boral®; boron steel, and other materials (excluding Boraflex) Spent fuel storage racks: neutron-absorbing sheets (PWR), Spent fuel storage racks: neutron-absorbing sheets (BWR) exposed to Treated borated water, Treated water (3.3.1-102)	Reduction of neutron-absorbing capacity; change in dimensions and loss of material caused by effects of SFP environment	Chapter XI.M40, "Monitoring of Neutron-Absorbing Materials other than Boraflex"	No	Monitoring of Neutron Absorbing Materials other than Boraflex	Consistent with the GALL Report
Reinforced concrete, asbestos cement Piping, piping components, and piping elements exposed to Soil or concrete (3.3.1-103)	Cracking caused by aggressive chemical attack and leaching; Changes in material properties caused by aggressive chemical attack	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)
HDPE, Fiberglass Piping, piping components, and piping elements exposed to Soil or concrete (3.3.1-104)	Cracking, blistering, change in color caused by water absorption	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Buried and Underground Piping and Tanks	Consistent with the GALL Report
Concrete cylinder piping, Asbestos cement pipe Piping, piping components, and piping elements exposed to Soil or concrete (3.3.1-105)	Cracking, spalling, corrosion of rebar caused by exposure of rebar	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)
Steel (with coating or wrapping) Piping, piping components, and piping elements exposed to Soil or concrete (3.3.1-106)	Loss of material caused by general, pitting, crevice, and microbiologically-influenced corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Buried and Underground Piping and Tanks	Consistent with the GALL Report
Stainless steel, nickel alloy, Piping, piping components, and piping elements exposed to Soil or concrete (3.3.1-107)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Buried and Underground Piping and Tanks	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Titanium, Super-austenitic, Aluminum, Copper-alloy, Stainless Steel, nickel alloy, Piping, piping components, and piping elements, Bolting exposed to Soil or concrete (3.3.1-108)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)
Steel Bolting exposed to Soil or concrete (3.3.1-109)	Loss of material caused by general, pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Buried and Underground Piping and Tanks	Consistent with the GALL Report
Underground Aluminum, Copper-alloy, Stainless Steel, nickel alloy and Steel Piping, piping components, and piping elements (3.3.1-109a)	Loss of material caused by general (steel only), pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Buried and Underground Piping and Tanks	Consistent with the GALL Report
Stainless steel Piping, piping components, and piping elements exposed to Treated water >60 °C (>140 °F) (3.3.1-110)	Cracking caused by stress corrosion cracking	Chapter XI.M7, "BWR Stress Corrosion Cracking," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.1.1)
Steel Structural steel exposed to Air – indoor, uncontrolled (External) (3.3.1-111)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring	Consistent with the GALL Report
Steel Piping, piping components, and piping elements exposed to concrete (3.3.1-112)	None	None, provided 1) attributes of the concrete are consistent with ACI 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG-1557, and 2) plant OE indicates no degradation of the concrete	No, if conditions are met.	None	Consistent with GALL Report (see SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Aluminum Piping, piping components, and piping elements exposed to Air – dry (Internal/External), Air – indoor, uncontrolled (Internal/External), Air – indoor, controlled (External), Gas (3.3.1-113)	None	None	NA - No AEM or AMP	None	Consistent with the GALL Report
Copper-alloy Piping, piping components, and piping elements exposed to Air – indoor, uncontrolled (Internal/External), Air – dry, Gas (3.3.1-114)	None	None	NA - No AEM or AMP	None	Consistent with the GALL Report
Copper-alloy (≤15% Zn and ≤8% Al) Piping, piping components, and piping elements exposed to Air with borated water leakage (3.3.1-115)	None	None	NA - No AEM or AMP	None	Consistent with the GALL Report
Galvanized steel Piping, piping components, and piping elements exposed to Air - indoor, uncontrolled (3.3.1-116)	None	None	NA - No AEM or AMP	None	Consistent with the GALL Report
Glass Piping elements exposed to Air – indoor, uncontrolled (External), Lubricating oil, Closed-cycle cooling water, Air – outdoor, Fuel oil, Raw water, Treated water, Treated borated water, Air with borated water leakage, Condensation (Internal/External) Gas (3.3.1-117)	None	None	NA - No AEM or AMP	None	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Nickel alloy Piping, piping components, and piping elements exposed to Air – indoor, uncontrolled (External) (3.3.1-118)	None	None	NA - No AEM or AMP	None	Consistent with the GALL Report
Nickel alloy, PVC, Glass Piping, piping components, and piping elements exposed to Air with borated water leakage, Air – indoor, uncontrolled, Condensation (Internal), Waste Water (3.3.1-119)	None	None	NA - No AEM or AMP	None	Consistent with the GALL Report
Stainless steel Piping, piping components, and piping elements exposed to Air – indoor, uncontrolled (Internal/External), Air – indoor, uncontrolled (External), Air with borated water leakage, Concrete, Air – dry, Gas (3.3.1-120)	None	None	NA - No AEM or AMP	None	Consistent with GALL Report (see SER Section 3.3.2.1.15)
Steel Piping, piping components, and piping elements exposed to Air – indoor, controlled (External), Air – dry, Gas (3.3.1-121)	None	None	NA - No AEM or AMP	None	Consistent with the GALL Report
Titanium Heat exchanger components, Piping, piping components, and piping elements exposed to Air – indoor, uncontrolled or Air – outdoor (3.3.1-122)	None	None	NA - No AEM or AMP	None	Not applicable to Callaway (see SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Titanium (ASTM Grades 1,2, 7, 11, or 12 that contains >5% aluminum or more than 0.20% oxygen or any amount of tin) Heat exchanger components other than tubes, Piping, piping components, and piping elements exposed to Raw water (3.3.1-123)	None	None	NA - No AEM or AMP	None	Not applicable to Callaway (see SER Section 3.3.2.1.1)
Stainless steel, Steel (with stainless steel or nickel-alloy cladding) Spent fuel storage racks (BWR), Spent fuel storage racks (PWR), Piping, piping components, and piping elements; exposed to Treated water >60°C (>140°F), Treated borated water >60°C (>140°F) (3.3.1-124)	Cracking due to stress corrosion cracking	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report
Steel (with stainless steel cladding); stainless steel Spent fuel storage racks (BWR), Spent fuel storage racks (PWR), Piping, piping components, and piping elements; exposed to Treated water, Treated borated water (3.3.1-125)	Loss of material due to pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report (see SER Section 3.3.2.1.16)
Any material piping, piping components and piping elements exposed to reactor coolant (3.3.1-126)	Wall thinning due to erosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No	Open-Cycle Cooling Water System	Consistent with the GALL Report (see SER Section 3.3.2.1.17)
Metallic piping, piping components, and tanks exposed to raw water or waste water (3.3.1-127)	Loss of material due to recurring internal corrosion	A plant-specific aging management program is to be evaluated to address recurring internal corrosion	Yes, plant-specific (see SER Section 3.3.2.2.8)	Open-Cycle Cooling Water System	Consistent with the GALL Report (see SER Section 3.3.2.2.8)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel, stainless steel, or aluminum tanks (within the scope of Chapter XI.M29, "Aboveground Metallic Tanks") exposed to soil or concrete, or the following external environments air-outdoor, air-indoor uncontrolled, moist air, condensation (3.3.1-128)	Loss of material due to general (steel only), pitting, or crevice corrosion; cracking due to stress corrosion cracking (stainless steel and aluminum)	Chapter XI.M29, "Aboveground Metallic Tanks"	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)
Metallic piping, piping components, heat exchangers, tanks with Service Level III (augmented) internal coatings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water, lubricating oil, or fuel oil (3.3.1-128a)	Loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage	Chapter XI.M42, "Service Level III (augmented) Coatings Monitoring and Maintenance Program"	No	Open-Cycle Cooling Water System, Fire Water System, Fuel Oil Chemistry, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.3.2.1.19)
Steel tanks exposed to soil or concrete; air-indoor uncontrolled, raw water, treated water, waste water, condensation (3.3.1-129)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M29, "Aboveground Metallic Tanks"	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)
Metallic sprinklers exposed to air-indoor controlled, air-indoor uncontrolled, air-outdoor, moist air, condensation, raw water, treated water (3.3.1-130)	Loss of material due to general (where applicable), pitting, crevice, and microbiologically influenced corrosion, fouling that leads to corrosion; flow blockage due to fouling	Chapter XI.M27, "Fire Water System"	No	Fire Water System	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel, stainless steel, copper alloy, or aluminum fire water system piping, piping components and piping elements exposed to air-indoor uncontrolled (internal), air-outdoor (internal), or condensation (internal) (3.3.1-131)	Loss of material due to general (steel, and copper alloy only), pitting, crevice, and microbiologically influenced corrosion, fouling that leads to corrosion; flow blockage due to fouling	Chapter XI.M27, “Fire Water System”	No	Fire Water System	Consistent with the GALL Report
Insulated steel, stainless steel, copper alloy, aluminum, or copper alloy (>15% Zn) piping, piping components, and tanks exposed to condensation, air-outdoor (3.3.1-132)	Loss of material due to general (steel, and copper alloy only), pitting, and crevice corrosion; cracking due to stress corrosion cracking (aluminum, stainless steel and copper alloy (>15% Zn) only)	Chapter XI.M36, “External Surfaces Monitoring of Mechanical Components” or Chapter XI.M29, “Aboveground Metallic Tanks” (for tanks only)	No	External Surfaces Monitoring of Mechanical Components	Consistent with the GALL Report
Underground HDPE piping, piping components, and piping elements in an air-indoor uncontrolled or condensation (external) environment (3.3.1-133)	Cracking, blistering, change in color due to water absorption	Chapter XI.M41, “Buried and Underground Piping and Tanks”	No	Buried and Underground Piping and Tanks	Consistent with the GALL Report
Steel, stainless steel, or copper alloy piping, piping components, and piping elements, and heat exchanger components exposed to a raw water environment (for nonsafety-related components not covered by NRC GL 89-13) (3.3.1-134)	Loss of material due to general (steel and copper alloy only), pitting, crevice, and microbiologically influenced corrosion, fouling that leads to corrosion	Chapter XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	External Surfaces Monitoring of Mechanical Components	Consistent with the GALL Report (see SER Section 3.3.2.1.5

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel or stainless steel pump casings submerged in a waste water (internal and external) environment (3.3.1-135)	Loss of material due to general (steel only), pitting, crevice, and microbiologically influenced corrosion	Chapter XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	Bolting Integrity	Consistent with the GALL Report (see SER Section 3.3.2.1.5)
Steel, stainless steel, or aluminum fire water storage tanks exposed to air-indoor uncontrolled, air-outdoor, condensation, moist air, raw water, treated water (3.3.1-136)	Loss of material due to general (steel only), pitting, crevice, and microbiologically influenced corrosion, fouling that leads to corrosion; cracking due to stress corrosion cracking (stainless steel and aluminum only)	Chapter XI.M27, "Fire Water System"	No	Fire Water System	Consistent with the GALL Report
Steel, stainless steel, or aluminum tanks (within the scope of Chapter XI.M29, “Aboveground Metallic Tanks”) exposed to treated water, treated borated water (3.3.1-137)	Loss of material due to general (steel only) pitting and crevice corrosion	Chapter XI.M29, “Aboveground Metallic Tanks”	No	Not applicable	Not applicable to Callaway (see SER Section 3.3.2.1.1)

3.3.2.1 AMR Results Consistent with the GALL Report

LRA Section 3.3.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the auxiliary systems components:

- Aboveground Metallic Tanks
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
- Bolting Integrity
- Boric Acid Corrosion
- Buried and Underground Piping and Tanks
- Closed Treated Water Systems
- External Surfaces Monitoring of Mechanical Components

- Fire Protection
- Fire Water System
- Fuel Oil Chemistry
- Flow-Accelerated Corrosion
- 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
- Monitoring of Neutron-Absorbing Materials other than Boraflex
- One-Time Inspection
- One-Time Inspection of ASME Code Class 1 Small-Bore Piping
- Open-Cycle Cooling Water System
- Selective Leaching
- Structures Monitoring
- Water Chemistry

LRA Tables 3.3.2-1 through 3.3.2-29 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 claimed consistency and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine if the plant-specific components in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR item. 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–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 AMR 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 AMR 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 AMR 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 audited these AMR 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 AMR 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 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 identified the appropriate GALL Report AMRs. The staff's evaluation is discussed below.

3.3.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.3-1, items 3.3.1-16, 3.3.1-24, 3.3.1-25, 3.3.1-27, and 3.3.1-110, 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 that these items are not applicable to Callaway, which is a PWR.

For LRA Table 3.3-1, items 3.3.1-10, 3.3.1-23, 3.3.1-30, 3.3.1-30, 3.3.1-31, 3.3.1-33, 3.3.1-48, 3.3.1-51, 3.3.1-65, 3.3.1-67, 3.3.1-73 through 3.3.1-75, 3.3.1-77, 3.3.1-101, 3.3.1-103, 3.3.1-105, 3.3.1-108, 3.3.1-122, 3.3.1-123, 3.3.1-128, 3.3.1-129, and 3.3.1-137, the applicant claimed that the corresponding items in the GALL Report are not applicable because the component, material, and environment combination described in the SRP-LR does not exist for in-scope SCs at Callaway. The staff reviewed the LRA and FSAR and confirmed that the applicant's LRA does not have any AMR results applicable for these items.

For LRA Table 3.3-1 items discussed below, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable; however, the staff non-applicability verification of these items required the review of sources beyond the LRA and FSAR, and/or the issuance of RAIs.

LRA Table 3.3-1, item 3.3.1-13 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 caused by general corrosion for this component group. The applicant stated that this item is not applicable because closure bolting was evaluated using plant indoor air as the external environment and SRP-LR Table 3.3-1, item 3.3.1-12 for steel closure bolting exposed to an air-indoor uncontrolled environment instead of item 3.3.1-13. The staff evaluated

the applicant's claim and finds it acceptable because the component group is being managed for the loss of material aging effect by the Bolting Integrity Program, consistent with the GALL Report recommendations.

LRA Table 3.3-1, item 3.3.1-17 addresses stainless steel heat exchanger tubes exposed to treated water or treated, borated water. The GALL Report recommends AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection," to manage reduction of heat transfer caused by fouling for this component group. The applicant stated that this item is not applicable because it only applies to BWRs. However, in its review of the applicant's claim, the staff noted that LR-ISG-2011-01, "Aging Management of Stainless Steel Structures and Components in Treated Borated Water," discussed the applicability of reduction of heat transfer for components in both treated water and treated borated water. Therefore, the staff required additional information to ensure that the aging effects for this component group was being adequately managed. By letter dated August 16, 2012, the staff issued RAI 3.3.1.17-1 requesting the applicant to justify the non-applicability of item 3.3.1-17. In its response dated September 20, 2012, the applicant added item 3.3.1-17 to LRA Tables 3.3.2-2 and 3.3.2-10 reflecting reduction of heat transfer as an aging effect for the stainless steel heat exchanger tubes in the fuel pool cooling and CVC seal water heat exchangers. The applicant also revised LRA Table 3.3-1, item 3.3.1-17 as being consistent with the GALL Report. The staff finds the applicant's response acceptable because, consistent with SRP-LR A.1.2.1, the applicant's determination of applicable aging effects is now based on those aging effects that potentially could cause component degradation. The staff notes that the applicant's use of the Water Chemistry and One-Time Inspection Programs to manage reduction of heat transfer in the heat exchanger tubes exposed to treated borated water for item 3.3.1-17 is consistent with the GALL Report. The staff's concern described in RAI 3.3.1.17-1 is resolved.

LRA Table 3.3-1, item 3.3.1-19 addresses stainless steel regenerative heat exchanger components exposed to treated water. The GALL Report recommends AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection," to manage cracking caused by SCC for this component group. The applicant stated that this item is not applicable because it only applies to BWRs. In its review of the applicant's claim, the staff noted that LRA Table 3.3-1, item 3.3.1-20 also addresses stainless steel heat exchanger components exposed to treated borated water and uses the same AMPs as those recommended for item 3.3.1-19. The staff also noted that the applicant extensively cited item 3.3.1-20 in several of the auxiliary system "Summary of Aging Management Evaluation," tables. The staff accepts the applicant's claim that item 3.3.1-19 is not applicable because the applicant is using an alternate AMR item, item 3.3.1-20, which uses the same AMPs to manage this aging effect for these components.

LRA Table 3.3-1, item 3.3.1-22 addresses copper-alloy piping, piping components, and piping elements exposed to treated water. The GALL Report recommends GALL Report AMPs XI.M2, "Water Chemistry," and XI.M32, "One-Time Inspection" to manage loss of material for this component group but states that the item is for BWRs only. The applicant stated that this item is not applicable because it is only applicable to BWRs. However, the staff noted that PWRs may have copper alloy components exposed to treated water in the auxiliary systems, and that this is the case at Callaway. The staff evaluated the applicant's claim and finds it acceptable because the applicant used LRA Table 3.4-1, item 3.4.1-16, to manage aging for copper alloy items exposed to treated water in the auxiliary systems, which manages aging consistent with the recommendations in item 3.3.1-22.

LRA Table 3.3.1, item 3.3.1-26 addresses steel (with elastomer lining or stainless steel cladding) piping, piping components and piping elements exposed to treated water. The GALL

Report recommends GALL Report AMPs XI.M2, “Water Chemistry,” and XI.M32, “One-Time Inspection,” to manage loss of material caused by pitting and crevice corrosion (only for steel after lining or cladding degradation for this component group). The applicant stated that this item is not applicable because “Callaway has no in-scope steel (with elastomer lining or stainless steel cladding) piping, piping components or piping elements exposed to treated water in the fuel pool cooling and clean up system, so the applicable NUREG-1801 lines were not used.” The staff finds that the applicant’s claim acceptable because SRP-LR item 3.3.1-26, which cites GALL Report items VII.A3.AP-107 and VII.A4.AP-108, is only associated with spent fuel pool cooling and cleanup system; and based on a review of the FSAR, there is no steel piping in this system except for that with an internal environment of closed-cycle cooling water which is being managed for loss of material by the Closed Treated Water Systems Program.

LRA Table 3.3-1, item 3.3.1-34 addresses nickel alloy and copper-alloy piping components exposed to raw water. The GALL Report recommends GALL Report AMP XI.M20, “Open-Cycle Cooling Water System,” to manage loss of material caused by general, pitting, and crevice corrosion for this component group. The applicant stated that this item is not applicable because Callaway has no in-scope nickel alloy components exposed to raw water in the auxiliary systems, and because the copper alloy components are being addressed in items 3.3.1-35, 3.3.3-36, and 3.3.1-38. The staff evaluated the applicant’s claim and finds it acceptable because the staff reviewed LRA Sections 2.3.3 and 3.3 and FSAR Section 9.2, “Water Systems,” and confirmed that there were no in-scope nickel alloy components exposed to raw water. In addition, the staff confirmed that the LRA addressed copper alloy components exposed to raw water through items 3.3.1-35, 3.3.3-36, and 3.3.1-38, which also specify the Open-Cycle Cooling Water System Program as the applicable AMP.

LRA Table 3.3-1, item 3.3.1-39 addresses stainless steel piping components exposed to raw water. The GALL Report recommends GALL Report AMP XI.M20, “Open-Cycle Cooling Water System,” to manage loss of material caused by pitting and crevice corrosion and fouling that leads to corrosion for this component group. The applicant stated that this item is not applicable because Callaway has no in-scope stainless steel piping components exposed to raw water in the UHS, and because stainless steel piping components in the ESW system are being managed by GALL Report items from Section VII.C1, “Open-Cycle Cooling Water System.” The staff evaluated the applicant’s claim and finds it acceptable because the staff reviewed LRA Sections 2.3.3 and 3.3 and FSAR Section 9.2, “Water Systems,” and confirmed that there were no in-scope stainless steel components exposed to raw water in the UHS system. In addition, the staff confirmed that the LRA addressed stainless steel components exposed to raw water in the auxiliary systems through item 3.3.1-40, which also specifies the Open-Cycle Cooling Water System Program as the applicable AMP.

LRA Table 3.3-1, item 3.3.1-44 addresses stainless steel and steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water greater than 60 °C (140 °F). The GALL Report recommends GALL Report AMP XI.M21A, “Closed Treated Water Systems,” to manage cracking caused by SCC for this component group. The applicant stated that this item is not applicable because it is applicable to BWR plants only. The staff noted that SRP-LR Table 3.3-1, item 44 is applicable to PWR and BWR plants; however, the corresponding AMR item in the GALL Report is for the reactor water cleanup system, which is a BWR system. The staff evaluated the applicant’s claim and found it acceptable because the staff confirmed that stainless steel heat exchanger components exposed to closed-cycle cooling water greater than 60 °C (140 °F) in the auxiliary systems reference an alternative piping item, LRA item 3.3.1-43, which manages for cracking caused by SCC in a manner consistent with LRA item 3.3.1-44 and GALL Report recommendations.

LRA Table 3.3-1, item 3.3.1-47 addresses stainless steel and steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water. The GALL Report recommends GALL Report AMP XI.21A, “Closed Treated Water Systems,” to manage loss of material caused by MIC for this component group. The applicant stated that this item is not applicable because it is applicable to BWR plants only. Although SRP-LR Table 3.3-1, item 47, does not explicitly state that MIC is applicable to PWR plants, the staff noted that EPRI 1007820, “Closed Cooling Water Chemistry Guideline, Revision 1,” states that microbiological organisms can be found in virtually all closed cooling water systems. The staff also noted that, as documented in the staff’s Audit Report of the Closed Treated Water Systems Program, the applicant is managing loss of material caused by MIC in its closed treated water systems by monitoring bacteria counts and has provisions in its procedures for adding biocides on an as-needed basis. The staff further noted that the LRA contains AMR items for stainless steel heat exchanger components exposed to closed cycle cooling water that are managed for loss of material with the Closed Treated Water Systems Program. As a result, the staff finds that the applicant is appropriately managing loss of material caused by MIC for the subject components through the water chemistry controls and visual inspections for corrosion in the Closed Treated Water Systems Program, consistent with GALL Report guidance.

LRA Table 3.3-1, item 3.3.1-86 addresses elastomer linings, seals, and components exposed to treated borated water, treated water, and raw water. The GALL Report recommends GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to manage hardening and loss of strength caused by elastomer degradation for this component group. The applicant stated that this item is not applicable because, “Callaway has no in-scope elastomers or linings, exposed to treated borated water within the fuel pool cooling and cleanup system, so the applicable NUREG-1801 lines were not used.” The staff finds that the applicant’s claim acceptable because SRP-LR item 3.3.1-86, which cites GALL Report items VII.A3.AP-100 and VII.A4.AP-101, is only associated with spent fuel pool cooling and cleanup system; and based on a review of the FSAR and LRA, there are no elastomer lined components in the spent fuel pool cooling and cleanup system.

During its review of the LRA, the staff noted that the applicant cited SRP-LR items 3.3.1-112 and 3.3.1-120 for several steel and stainless steel piping, piping components, and other component types embedded in concrete. There is an internal misalignment in the GALL Report in that the definition of buried piping and scope of AMP XI.M41 conflicts with items 3.3.1-112 and 3.3.1-120, which state that there are no AERM or recommended AMP for the concrete environment. Regardless of the misalignment, the staff lacks sufficient information to conclude that the in-scope steel and stainless steel piping and piping components embedded in concrete do not need to be age managed. For example, if steel piping embedded in concrete is within a building or under a building but above the water table, the potential for water intrusion into the concrete is very low, and therefore, the conditional statements associated with SRP-LR item 3.3.1-112 represent a sufficient basis for why there are no aging effects for these items. By letter dated July 5, 2012, the staff issued RAI 3.3.1-1 requesting that the applicant state the basis for why there are no aging effects for these items.

In its response dated August 6, 2012, and amended by letter dated August 21, 2012, the applicant stated that it has floor and equipment drains which are located inside of buildings, metal dampers, and essential service water piping that is embedded in concrete and within a building, and structural steel anchorages where the potential for water intrusion into the concrete is very low. The applicant also stated that are no in-scope steel or stainless steel piping or piping components that transition directly from a buried environment to an embedded in concrete environment in that buried piping which enters buildings passes through sleeved

penetrations in the building walls which have elastomeric water seals to prevent moisture intrusion into the building.

The staff finds the applicant's response acceptable because despite the internal misalignment within the GALL Report, given that these components are not exposed to the potential for groundwater intrusion into the concrete, there is no AERM for steel and stainless steel piping components embedded in dry concrete as stated in SRP-LR items 3.3.1-112 and 3.3.1-120. The staff's concern described in RAI 3.3.1-1 is resolved.

3.3.2.1.2 Cracking Due to Stress Corrosion Cracking

LRA Table 3.3-1, item 3.3.1-28 addresses stainless steel pipes, piping components, piping elements, and heat exchangers exposed to treated borated water which will be managed for cracking due to SCC. 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 these components with this material and environment combination.

The staff noted that, during the LRA review, the environment for this item changed to treated borated water in primary systems (oxygen levels controlled), following the revised guidance in LR-ISG-2011-01. By letter dated December 19, 2012, the applicant revised the LRA AMR items that are associated with item 3.3.1-28. For these items, the applicant proposes to manage aging with the Water Chemistry program, citing generic note A to reflect the LRA consistency with the revised GALL Report guidance. The staff confirmed the consistency with the GALL Report and, therefore, finds the applicant's proposal to manage aging acceptable.

LRA Table 3.3-1, item 3.3.1-124 was added to the LRA by letter dated December 19, 2012, in response to the issuance of LR-ISG-2011-01. Item 3.3.1-124 addresses stainless steel spent fuel storage equipment, piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated borated water. For the AMR items that cite generic notes A or C, the LRA credits the Water Chemistry and One-Time Inspection Programs to manage cracking due to SCC for stainless steel components in treated borated water. The GALL Report, as revised by LR-ISG-2011-01, recommends GALL Report AMPs XI.M2, "Water Chemistry," and XI.M32, "One-Time Inspection," to ensure that these aging effects are adequately managed. The staff confirmed the consistency with the GALL Report and, therefore, finds the applicant's proposal to manage aging acceptable.

The staff concludes that for LRA item 3.3.1-28, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.1.3 Loss of Material Due to Pitting and Crevice Corrosion

LRA Table 3.3-1, item 3.3.1-29 addresses steel (with stainless steel cladding) and stainless steel piping, piping components, and piping elements exposed to treated borated water (primary, oxygen levels controlled), which will be managed for loss of material due to pitting and crevice corrosion. The staff noted that, during the LRA review, the environment for this item changed to treated borated water in primary systems, following the revised SRP-LR and GALL Report guidance in LR-ISG-2011-01, Revision 1, "Aging Management of Stainless Steel Structures and Components in Treated Borated Water." Previously, item 3.3.1-29 did not specify that the environment was limited to primary water.

By letter dated December 19, 2012, the applicant revised the AMR items that are associated with item 3.3.1-29. For these items, the applicant proposes to manage aging with the Water Chemistry Program, citing generic note A to reflect the LRA consistency with the revised GALL Report guidance. The staff confirmed the consistency with the GALL Report and, therefore, finds the applicant's proposal to manage aging acceptable.

The staff concludes that for LRA item 3.3.1-29, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.1.4 Cracking Due to Aggressive Chemical Attack, Leaching; and Changes in Material Properties Due to Aggressive Chemical Attack

LRA Table 3.3-1, item 3.3.1-32 addresses reinforced concrete and asbestos cement piping components exposed to raw water which will be managed for cracking caused by aggressive chemical attack, leaching; and changes in material properties due to aggressive chemical attack. For the AMR item that cites generic note E, the LRA credits the External Surfaces Monitoring of Mechanical Components Program to manage the aging effect for asbestos cement splash panels. 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 routine inspections to manage this type of aging.

The staff's evaluation of the applicant's External Surfaces Monitoring of Mechanical Components Program is documented in SER Section 3.0.3.1.10. The staff noted that the External Surfaces Monitoring of Mechanical Components Program proposes to manage the aging of asbestos cement splash panels through the use of periodic visual inspections. In its review of components associated with item 3.3.1-32 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the External Surfaces Monitoring of Mechanical Components Program acceptable because the proposed program conducts visual inspections which are able to detect cracking of components.

The staff concludes that for LRA item 3.3.1-32, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.1.5 Loss of Material Due to General, Pitting, Crevice and Microbiologically-Influenced Corrosion; and Fouling that Leads to Corrosion

LRA Table 3.3-1, items 3.3.1-36 and 3.3.1-37, address steel and copper alloy piping, piping components, piping elements, and heat exchanger components and steel tanks exposed to raw water, which will be managed for loss of material due to general, pitting, crevice, and microbiologically influenced corrosion, and fouling that leads to corrosion. For the AMR items that cite generic note E, the LRA credits the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components Program to manage the aging effect for carbon steel and copper alloy piping components and the Fire Water System Program to manage the aging effect for carbon steel fire water tanks. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that this aging effect is adequately managed for safety-related service water system components, as defined by GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment." However, the staff noted that, because

the subject components are not within the essential service water system, GALL Report AMP XI.M20 is not applicable.

The staff's evaluation of the applicant's Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.12. The staff noted that this program uses visual inspections performed during surveillances and maintenance activities when the surfaces are made available for inspection to manage aging. Also, at a minimum, in each 10-year period during the period of extended operation, a representative sample of the inspection population is inspected. The staff finds the applicant's proposal to manage aging of carbon steel and copper alloy piping components using the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components Program acceptable because the proposed program conducts opportunistic and periodic visual inspections that are capable of identifying loss of material prior to loss of intended function(s).

The staff's evaluation of the applicant's Fire Water System Program is documented in SER Section 3.0.3.2.7. The staff noted that the program proposes to manage the aging of fire water tanks through the use of periodic visual inspections, as recommended by NFPA 25, "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems." The staff noted that NFPA 25 Section 9.2.6 states that inspections for corrosion and coating degradation occur every 3 years. The staff also noted that the use of NFPA 25 is consistent with the guidance in LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation." In its review of carbon steel tanks associated with item 3.3.1-37, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Fire Water System Program acceptable because the proposed program conducts periodic visual inspections in accordance with NFPA 25 that are capable of identifying loss of material prior to loss of intended function(s).

The staff concludes that, for LRA items 3.3.1-36 and 3.3.1-37, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

LRA Table 3.3-1, item 3.3.1-40, as amended by letters dated August 29, 2013, and January 16, 2014, addresses stainless steel piping, piping components, piping elements, heat exchanger components, tanks, and bolting exposed to raw water which will be managed for loss of material due to pitting and crevice corrosion and fouling that leads to corrosion. For the AMR item that cites generic note E, the LRA credits the Bolting Integrity Program to manage the aging effect for stainless steel closure bolting in the essential service water system. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure that this aging effect is adequately managed for safety-related service water system components. GALL Report AMP XI.M20 recommends visual or nondestructive inspections to determine if corrosion is occurring, with a frequency in accordance with the applicant's response to GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment."

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.2. The staff noted that the program proposes to manage the aging of submerged bolting associated with the essential service water system pumps by (a) quarterly testing of the pumps, which may detect bolting degradation that would be manifested in abnormal pump performance, (b) visual inspections of a sample of the bolt heads during dewatering of the intake bays, which occurs every four refueling outages, and (c) visual inspection of the bolt threads when pump casings are disassembled during maintenance

activities. In its review of stainless steel bolting associated with item 3.3.1-40, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the frequent pump performance monitoring can reveal gross bolting failures that would prevent the pump from delivering flow and the visual inspections of the bolt heads and threads described above are capable of identifying loss of material prior to loss of bolting intended functions.

The staff concludes that, for LRA item 3.3.1-40, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

LRA Table 3.3-1, item 3.3.1-71, as amended by letters dated August 29, 2013, and January 16, 2014, addresses stainless steel and aluminum piping, piping components, piping elements, and bolting exposed to fuel oil which will be managed for loss of material due to pitting, crevice, and microbiologically influenced corrosion. For the AMR item that cites generic note E, the LRA credits the Bolting Integrity Program to manage the aging effect for carbon steel closure bolting in the emergency diesel engine fuel oil storage and transfer system. The GALL Report recommends GALL Report AMP XI.M30, "Fuel Oil Chemistry," and XI.M32, "One-Time Inspection," to ensure that this aging effect is adequately managed. GALL Report AMPs XI.M30 and XI.M32 recommend that loss of material be managed by monitoring and controlling fuel oil quality and verifying the effectiveness of the oil quality controls through visual inspection of components exposed to fuel oil.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.2. The staff noted that the program proposes to manage the aging of submerged bolting associated with the fuel oil storage tank transfer pumps by (a) periodic testing of the pumps, which may detect bolting degradation that would be manifested in abnormal pump performance, and (b) visual inspection of a sample of the bolting when the pumps are disassembled during maintenance activities, which is performed on a 10-year frequency. In its review of stainless steel bolting associated with item 3.3.1-71, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the pump performance monitoring can reveal gross bolting failures that would prevent the pump from delivering flow and the visual inspections of the bolting during pump disassembly described above are capable of identifying loss of material prior to loss of bolting intended functions.

The staff concludes that, for LRA item 3.3.1-71, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

LRA Table 3.3-1, item 3.3.1-134, as amended by letters dated December 20, 2013, February 14, 2014, and April 23, 2014, addresses copper-alloy, steel, and stainless steel piping, piping components, and piping elements exposed to raw water which will be managed for loss of material due to general, pitting, crevice, and microbiologically influenced corrosion, and fouling that leads to corrosion. For the AMR items that cite generic note E, the LRA credits the External Surfaces Monitoring of Mechanical Components Program to manage aging effects for the internal and external surfaces of gray cast iron pumps. The GALL Report 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. GALL Report

AMP XI.M38 recommends using visual inspections performed during surveillances and maintenance activities when the surfaces are made available for inspection to manage aging. In addition, GALL Report AMP XI.M38 also recommends that, at a minimum, in each 10-year period during the period of extended operation, a representative sample of the inspection population be inspected.

The staff's evaluation of the applicant's External Surfaces Monitoring of Mechanical Components Program is documented in SER Section 3.0.3.1.10. The staff noted that the External Surfaces Monitoring of Mechanical Components Program proposes to manage aging through the use of periodic visual inspections, conducted at least once every refueling cycle. In its review of components associated with item 3.3.1-134, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the External Surfaces Monitoring of Mechanical Components Programs acceptable because the proposed program conducts periodic visual inspections at a greater frequency than the GALL-recommended AMP, and the inspections are capable of identifying loss of material prior to loss of intended function(s). The staff also noted that the internal and external environments are the same for the gray cast iron pumps in the service water system, which, in accordance with the GALL Report AMP XI.M36, allows the External Surfaces Monitoring of Mechanical Components Program to be credited for managing the loss of material from internal surfaces as well.

The staff concludes that for LRA item 3.3.1-134 the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

LRA Table 3.3-1, item 3.3.1-135, as amended by letters dated August 29, 2013, December 20, 2013, and January 16, 2014, addresses carbon steel and stainless steel pumps and associated bolting exposed to waste water which will be managed for loss of material due to general (steel only) pitting, crevice, and microbiologically influenced corrosion. For the AMR items that cite generic note E, the LRA credits the Bolting Integrity Program to manage the aging effect for carbon steel and stainless steel closure bolting in the oily waste system and floor and equipment drains system. The GALL Report recommends GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," to ensure that this aging effect is adequately managed. GALL Report AMP XI.M36 recommends that loss of material be managed by periodic visual inspections, conducted at least once per refueling outage, to detect corrosion and material wastage of metallic components.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.2. The staff noted that the program proposes to manage the aging of submerged bolting by (a) monitoring of the waste water sumps during operator rounds to confirm that they are being drained, which may detect bolting degradation that would be manifested in abnormal pump performance; (b) visual inspections of a sample of the bolt heads when the pumps are dewatered, but at least once every four refueling outages; and (c) visual inspection of the bolt threads when pump casings are disassembled during maintenance activities. In its review of stainless steel bolting associated with item 3.3.1-71, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the pump performance monitoring can reveal gross bolting failures that would prevent the pump from delivering flow and the visual inspections of the bolt heads and threads described above are capable of identifying loss of material prior to loss of bolting intended functions.

The staff concludes that for LRA item 3.3.1-135 the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.1.6 Loss of Material Due to General, Pitting, and Crevice Corrosion

LRA Table 3.3-1, item 3.3.1-54 addresses copper-alloy piping, piping components, and piping elements exposed to condensation which will be managed for loss of material due to general, pitting, and crevice corrosion. LRA Table 3.3-1, item 3.3.1-55 addresses steel compressed air system piping, piping components, and piping elements exposed to condensation which will be managed for loss of material due to general and pitting corrosion. LRA Table 3.3-1, item 3.3.1-56 addresses stainless steel compressed air system piping, piping components, and piping elements exposed to condensation which will be managed for loss of material caused by 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 copper-alloy piping and valves, steel piping and valves, and stainless steel flow orifice, piping, and valves. The GALL Report recommends GALL Report AMP XI.M24, "Compressed Air Monitoring," to ensure that the aging effect is adequately managed. GALL Report AMP XI.M24 recommends monitoring of air quality and inspection of the internal surfaces of critical components to manage aging.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.12. The staff noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program proposes to manage loss of material of internal surfaces of various components exposed to condensation through the use of opportunistic visual inspections of the internal surfaces of the components. Based on its review of components associated with items 3.3.1-54, 3.3.1-55, and 3.3.1-56, 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 opportunistic visual inspections of the internal surfaces of the compressed air system components will ensure that if a loss of material is occurring, it will be detected prior to a loss of intended function (e.g., pressure boundary). Although GALL Report AMP XI.M24 also recommends monitoring of air quality, the components primarily responsible for achieving air quality (e.g., air dryers, after filters) are not within the scope of license renewal. Furthermore, the applicant does not assume that the air is dry rather it considers the environment to be "condensation." Thus, monitoring of air quality for the purpose of aging management is unnecessary for copper-alloy, steel and stainless steel piping, piping components, and piping elements in the compressed air system.

The staff concludes that for LRA items 3.3.1-54, 3.3.1-55, and 3.3.1-56, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.1.7 Hardening and Loss of Strength Due to Elastomer Degradation

LRA Table 3.3-1, item 3.3.1-76 addresses external and internal surfaces of elastomeric seals and components exposed to uncontrolled indoor air which will be managed for hardening and loss of strength due to elastomer degradation. The GALL Report recommends GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," to ensure that these aging effects are adequately managed. During its review of components associated with

item 3.3.1-76, for which the applicant cited generic note A, the staff noted that the LRA credits the External Surfaces Monitoring of Mechanical Components Program to manage the aging effects for flexible hoses in LRA Table 3.4.2-5; however, the staff did not know if these hoses are sufficiently flexible such that manipulation of the external surface will result in inspection results which are representative of internal conditions. In addition, the staff lacked sufficient information on the use of the flexible hoses to be able to conclude that there are no contaminants that could be present that could result in degradation on the internal surfaces of the hose that would not be detected by an external examination. By letter dated August 6, 2012, the staff issued RAI 3.3.2.28-1, Parts (a), (b), and (c), requesting that the applicant:

(a) State the basis for why the expansion joints and flexible hoses in LRA Tables 3.3.2-3 and 3.3.2-28, and the external surface of the flexible hoses in LRA Table 3.4.2-5, are not being managed for loss of material due to wear or propose how the aging effect will be managed.

(b) State whether the flexible hoses in LRA Table 3.4.2-5 are sufficiently flexible such that an external inspection would yield representative results of potential degradation of the internal surfaces. If they are not; state how hardening and loss of strength of the internal surfaces will be managed.

(c) State whether there are contaminants which could result in internal degradation of the flexible hoses in LRA Table 3.4.2-5, and if so, state how aging will be managed.

By letter dated September 6, 2012, the applicant provided its response to RAI 3.3.2.28-1, Parts (a), (b) and (c). The staff's evaluation of the applicant response to Part (a) is documented in SER Section 3.3.2.1.10. In response to Part (b) the applicant amended LRA Table 3.4.2-5 to include the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage hardening and loss of strength for the flexible hoses. In response to Part (c) the applicant stated that, "[t]here has been no plant operating experience at Callaway which would indicate that there are contaminants present for an internal environment of condensation," and "[t]he presence of contaminants or hard abrasive particles in the auxiliary feedwater system is extremely unlikely."

The staff finds the applicant's response acceptable because: (a) the applicant will manage the internal surfaces of the flexible hoses for hardening and loss of strength with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, which includes opportunistic visual and physical manipulation inspections of elastomeric and polymeric materials that are capable of detecting hardening and loss of strength; and (b) the applicant's response confirmed the staff's understanding that typical air environments within the power block would not result in contaminants or abrasives entering flexible hoses for this system. The staff's concerns described in RAI 3.3.2.28-1, Parts (b) and (c) are resolved.

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 function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.1.8 Loss of Material Due to General Corrosion

LRA Table 3.3-1, item 3.3.1-78 addresses steel piping, ducting, and closure bolting exposed to indoor uncontrolled air, outdoor air, or condensation 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 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage the aging effect for steel piping, ductwork, and fans exposed to ventilation atmosphere (external). The AMR items also cite a plant-specific note which states that the subject components are enclosed within other components. The GALL Report recommends GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," to ensure that these aging effects are adequately managed. Further, GALL Report AMP XI.M36 also recommends using visual inspections of external surfaces conducted during periodic plant system inspections and walkdowns to manage aging for this component group.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.12. The staff noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program proposes to manage loss of material for the components exposed to ventilation atmospheres using periodic, opportunistic visual inspections performed during surveillance and maintenance activities whenever the internal surfaces are made accessible for inspection. 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: (a) the subject components are enclosed within other components such that access to the external surface requires the surface be made accessible and (b) the proposed program includes visual inspections performed during surveillance and maintenance activities that are capable of identifying loss of material consistent with the GALL Report recommendations.

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 function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.1.9 Loss of Material Due to General, Pitting, and Crevice Corrosion

LRA Table 3.3-1, item 3.3.1-79 addresses copper-alloy piping, piping components, and piping elements exposed to condensation (external) 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, as amended by letter dated August 21, 2012, credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program or the Open-Cycle Cooling Water Program to manage the aging effect for piping and heat exchanger components exposed to plant indoor air (external) or ventilation atmosphere (internal or external). The AMR items that credit the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage aging also cite a plant-specific note which states that the subject components are enclosed within another component. The AMR items that credit the Open-Cycle Cooling Water Program to manage aging also cite a plant-specific note that states reduction of heat transfer and loss of material for the air-side of safety-related air-to-water heat exchangers is managed by the Open-Cycle Cooling Water System Program consistent with the Callaway commitments to GL 89-13. The GALL Report recommends GALL Report AMP XI.M36, "External Surfaces Monitoring," to ensure that these aging effects are adequately managed. GALL Report AMP XI.M36 recommends using periodic visual inspections of the external surfaces of components to manage aging for metallic components.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.12. The staff noted

that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program proposes to manage the aging of metallic components through the use of visual inspections. 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 acceptable because the program includes visual inspections of components which are capable of detecting loss of material and the subject components are either located inside other components, or exposed internally to an environment where condensation could occur.

The staff's evaluation of the applicant's Open-Cycle Cooling Water Program is documented in SER Section 3.0.3.2.3. The staff noted that the Open-Cycle Cooling Water Program proposes to manage the aging of the air side of safety-related air-to-water heat exchanger components through the use of visual inspections and, if necessary, cleaning. 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 Open-Cycle Cooling Water Program acceptable because the program includes visual inspections and cleaning of the air side of heat exchanger components, which are capable of detecting loss of material and is consistent with the applicant's existing commitments associated with GL 89-13.

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 function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.1.10 Loss of Material Due to Wear

LRA Table 3.3.1, item 3.3.1-82 addresses external surfaces of elastomeric seals and components exposed to uncontrolled indoor air which will be managed for loss of material due to wear. The GALL Report recommends GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," to ensure that these aging effects are adequately managed. During its review of components associated with item 3.3.1-82, for which the applicant cited generic note A, the staff noted that the LRA credits the External Surfaces Monitoring of Mechanical Components Program to manage the aging effects for expansion joints and flexible hoses in LRA Tables 3.3.2-23, 3.3.2-28, and 3.4.2-5; however, these items are being managed for hardening and loss of strength, but not loss of material caused by wear. GALL Report Section IX.F defines wear "as the removal of surface layers caused by relative motion between two surfaces or under the influence of hard, abrasive particles. Wear occurs in parts that experience intermittent relative motion, frequent manipulation, or in clamped joints where relative motion is not intended, but may occur because of a loss of the clamping force." It was unclear to the staff why the expansion joints and flexible hoses in LRA Tables 3.3.2-23 and 3.3.2-28, and the external surface of the flexible hoses in LRA Table 3.4.2-5, are not being managed for loss of material caused by wear due to possible relative motion, frequent manipulation, or loss of the clamping force over time. By letter dated August 6, 2012, the staff issued RAI 3.3.2.28-1, Part (a) requesting that the applicant state the basis for why the expansion joints and flexible hoses are not being managed for loss of material caused by wear, or propose how the aging effect will be managed. RAI 3.3.2.28-1 also included Parts (b) and (c). The staff evaluation of the applicant response to RAI 3.3.2.28-1, Parts (b) and (c) is documented in SER Section 3.3.2.1.7.

In its response to RAI 3.3.2.28-1, Part (a) dated September 6, 2012, the applicant amended LRA Tables 3.3.2-23, 3.3.2-28, and 3.4.2-5 to use the External Surfaces Monitoring of

Mechanical Components Program to manage loss of material for flexible hoses and expansion joints exposed to plant indoor air.

The staff finds the applicant's response acceptable because the applicant will manage the external surfaces of the flexible hoses and expansion joints for loss of material caused by wear with the External Surfaces Monitoring of Mechanical Components Program, which includes visual examinations that are capable of detecting loss of material caused by wear. The staff's concern described in RAI 3.3.2.28-1, Part (a) is resolved.

The staff concludes that for LRA item 3.3.1-82, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

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

LRA Table 3.3-1, item 3.3.1-90 addresses internal surfaces of steel ducting and components exposed to condensation, which will be managed for loss of material due to general, pitting, crevice corrosion, and (for drip pans and drain lines) MIC. For the AMR items that cite generic note E, the LRA credits the Fire Protection Program to manage the aging effect for carbon steel (galvanized) dampers exposed to ventilation atmosphere (internal). The GALL Report 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. GALL Report AMP XI.M38 recommends using periodic opportunistic visual inspections performed during surveillances and maintenance activities when the surfaces are made available for inspection to manage aging.

The staff's evaluation of the applicant's Fire Protection Program is documented in SER Section 3.0.3.2.6. The staff noted that the Fire Protection Program proposes to manage aging of carbon steel dampers through the use of periodic visual inspections of not less than 10 percent of the fire dampers at least once every 18 months. 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 Fire Protection Program acceptable because the program includes periodic visual inspections which are capable of detecting loss of material and are performed on a frequency consistent with the GALL Report recommendations for fire dampers.

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 function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.1.12 Loss of Material Due to Pitting and Crevice Corrosion

LRA Table 3.3-1, item 3.3.1-92 addresses aluminum piping, piping components, and piping elements exposed to condensation (internal), which will be managed for loss of material due to pitting and crevice corrosion. For the AMR item that cites generic note E, the LRA, as amended by letter dated August 21, 2012, credits the Open-Cycle Cooling Water System Program to manage the aging effect for aluminum HVAC heat exchangers in the control building. The GALL Report 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. GALL Report AMP XI.M38 recommends using opportunistic visual inspections to manage aging.

The staff's evaluation of the applicant's Open-Cycle Cooling Water System Program is documented in SER Section 3.0.3.2.3. The staff noted that the Open-Cycle Cooling Water System Program proposes to manage the aging of the air-side of safety-related air-to-water heat exchangers exposed to condensation (internal) through the use of periodic inspection and cleaning of heat exchangers with a heat transfer intended function, which is performed in accordance with Callaway commitments to NRC Generic Letter 89-13 to confirm heat transfer capabilities. In its review of components associated with item 3.3.1-92, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Open-Cycle Cooling Water System Program acceptable because the activities associated with the applicant's Open-Cycle Cooling Water System Program are consistent with the Callaway commitments to the requirements in Generic Letter 89-13 which identify periodic heat transfer testing or inspection and cleaning of heat exchangers with a heat transfer intended function as an appropriate method to detect aging effects associated with heat exchangers.

LRA Table 3.3-1, item 3.3.1-94 addresses stainless steel ducting and components exposed to condensation, 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, as amended by letter dated August 21, 2012, credits the Open-Cycle Cooling Water System Program to manage the aging effect for stainless steel HVAC in the auxiliary and fuel buildings, and auxiliary feedwater room heat exchangers. The GALL Report 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. GALL Report AMP XI.M38 recommends using opportunistic visual inspections to manage aging.

The staff's evaluation of the applicant's Open-Cycle Cooling Water System Program is documented in SER Section 3.0.3.2.3. The staff noted that the Open-Cycle Cooling Water System Program proposes to manage the aging of the air-side of safety-related air-to-water heat exchangers exposed to ventilation atmosphere through the use of periodic inspection and cleaning of heat exchangers with a heat transfer intended function, which is performed in accordance with NRC's GL 89-13 to confirm heat transfer capabilities. In its review of components associated with item 3.3.1-94, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Open-Cycle Cooling Water System Program acceptable because the activities associated with the applicant's Open-Cycle Cooling Water System Program are consistent with the Callaway commitments, as revised by letter dated July 16, 2007, to the requirements in GL 89-13 which identify periodic heat transfer testing or inspection and cleaning of heat exchangers with a heat transfer intended function as an appropriate method to detect aging effects associated with heat exchangers.

The staff concludes that for LRA items 3.3.1-92 and 3.3.1-94, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.1.13 Loss of Material Due to General, Pitting and Crevice Corrosion

LRA Table 3.3-1, item 3.3.1-97, addresses steel piping, piping components, piping elements, reactor coolant pump oil collection system tanks, reactor coolant pump oil collection system piping, tubing, and valve bodies exposed to lubricating oil 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 carbon steel and galvanized carbon steel piping and valves. The GALL Report recommends the GALL Report AMP XI.M39, "Lubricating Oil Analysis," to ensure that these aging effects are adequately managed. GALL Report AMP XI.M39 recommends sampling for water and a particle count to detect evidence of contamination by moisture or excessive corrosion to manage aging. The applicant cited plant-specific note 1 which states the following:

> [c]omponents associated with the reactor coolant pump oil collection system do not normally contain lubricating oil. Any oil or water that is found during operator visual inspections is documented and reviewed. If there is an accumulation of liquid, it is removed and discarded during the outage inspection. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components [P]rogram (B2.1.23) inspects the piping, valves and tank for loss of material to maintain these components' intended function.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.12. The staff noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program proposes to manage the aging of carbon steel and galvanized carbon steel piping and valves through the use of mechanical and visual inspections. In its review of components associated with item 3.3.1-97 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 components proposed to be managed under item 3.3.1-97 are part of the applicant's equipment and floor drainage system which collects drainage and leak-off from various systems and is not a closed system utilized solely for lubricating oil; therefore, sampling for water and particulate count to manage aging would be ineffective. The visual and mechanical inspections proposed in the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will provide actual detection of loss of material in the affected components and is therefore acceptable.

The staff concludes that for LRA Item 3.3.1-97, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.1.14 Loss of material due to pitting, crevice, and microbiologically influenced corrosion

LRA Table 3.3-1, item 3.3.1-100, addresses stainless steel piping, piping components, and piping elements exposed to lubricating oil (internal) which will be managed for loss of material due to pitting, crevice, and MIC. 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 stainless steel flexible hoses, piping, tanks, tubing, and valves. The GALL Report recommends the GALL Report AMP XI.M39, "Lubricating Oil Analysis," to ensure that these aging effects are adequately managed. GALL Report AMP XI.M39 recommends sampling for water and a particle count, to detect evidence of contamination by moisture or excessive corrosion, to manage aging. The applicant cited plant-specific note 1 which states the following:

> [c]omponents associated with the reactor coolant pump oil collection system do not normally contain lubricating oil. Any oil or water that is found during operator visual inspections is documented and reviewed. If there is an accumulation of

> liquid, it is removed and discarded during the outage inspection. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components [P]rogram (B2.1.23) inspects the piping, valves and tank for loss of material to maintain these components' intended function.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.12. The staff noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Proram proposes to manage the aging of stainless steel flexible hoses, piping, tanks, tubing, and valves. In its review of components associated with item 3.3.1-100 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 components proposed to be managed under item 3.3.1-100 are part of the applicant's equipment and floor drainage system which collects drainage and leak off from various systems and is not a closed system utilized solely for lubricating oil; therefore, sampling for water and particle count to manage aging would be ineffective. The visual and mechanical inspections proposed in the Inspection of Internal Surfaces In Miscellaneous Piping and Ducting Components Program will provide actual detection of loss of material in the affected components and is therefore acceptable.

The staff concludes that for LRA item 3.3.1-100, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.1.15 No Aging Effects Requiring Management

LRA Table 3.3-1, item 3.3.1-120 addresses stainless steel piping, piping components, and piping elements exposed to air-indoor uncontrolled, air with borated water leakage, concrete, air-dry, or gas and states that there are no AERM and no AMP is proposed. The GALL Report states that there are no AERM and no AMP is proposed for this component group.

During its review of components associated with item 3.3.1-120 for which the applicant cited generic note A, the staff noted that the LRA states that there are no AERM and no AMP is proposed for stainless steel expansion joints exposed internally to borated water leakage in LRA Table 3.3.2-2. However, the GALL Report environment of air with borated water leakage is usually referred to as an external environment. The GALL Report recommends that stainless steel components exposed to treated borated water or condensation be managed for loss of material. It was unclear to the staff how the components exposed internally to borated water leakage are configured such that exposure to borated water leakage can occur, but the leakage does not accumulate such that the environment becomes borated water or condensation. By letter dated August 16, 2012, the staff issued RAI 3.2.1.063-1 requesting that the applicant explain the configuration of the components exposed internally to borated water leakage and how accumulation of the borated water leakage is prevented. If accumulation of borated water leakage can occur; the staff requested the applicant to explain why the components have no AERM.

In its response dated September 20, 2012, the applicant stated that the expansion joint is part of the sleeve surrounding the fuel transfer tube. The applicant stated that the external surface of the expansion joint and sleeve are exposed to borated water during refueling operations, but the interior surfaces are dry because the sleeve is welded to the transfer tube. The applicant

revised LRA Table 3.3.2-2 to indicate that the internal environment for the expansion joint and the external environment for the fuel transfer tube is plant indoor air. The staff finds the applicant's response acceptable because the applicant described the configuration of the expansion joint and its relation to the fuel transfer tube , and clarified that normal internal environment is plant indoor air. Consistent with the GALL Report for this material and environment combination, no aging effects are expected; therefore, no aging management program is needed. The staff's concern described in RAI 3.2.1.063-1 is resolved.

The staff concludes that for LRA item 3.3.1-120, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.1.16 Loss of Material Due to Pitting and Crevice Corrosion

LRA Table 3.3-1, item 3.3.1-125 was added to the LRA by letter dated December 19, 2012, in response to the issuance of LR-ISG-2011-01, Revision 1, "Aging Management of Stainless Steel Structures and Components in Treated Borated Water." Item 3.3.1-125 addresses steel (with stainless steel cladding) and stainless steel spent fuel storage racks, piping, piping components, and piping elements exposed to treated water and treated borated water. For the AMR items that cite generic notes A or C, the LRA credits the Water Chemistry and One-Time Inspection Programs to manage loss of material caused by pitting and crevice corrosion for stainless steel components in treated borated water. The GALL Report, as revised by LR-ISG-2011-01, recommends GALL Report AMPs XI.M2, "Water Chemistry," and XI.M32, "One-Time Inspection," to ensure that these aging effects are adequately managed. The staff confirmed the consistency with the GALL Report and, therefore, finds the applicant's proposal to manage aging acceptable.

The staff concludes that for LRA item 3.3.1-125, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.1.17 Wall Thinning Due to Erosion

LRA Table 3.3-1, item 3.3.1-126, addresses piping, piping components, and piping elements made from any material exposed to treated water, treated borated water, or raw water which will be managed for wall thinning due to erosion. For the AMR item that cites generic note E, the LRA credits the Open-Cycle Cooling Water System program to manage the wall thinning due to erosion for carbon steel piping exposed to raw water. The GALL Report, as revised by LR-ISG-2012-01, recommends GALL Report AMP XI.M17, "Flow-Accelerated Corrosion," to ensure that this aging effect is adequately managed. GALL Report AMP XI.M17 recommends using periodic ultrasonic or radiographic examinations to monitor and trend wall thinning in order to manage aging.

The staff's evaluation of the applicant's Open-Cycle Cooling Water System program is documented in SER Section 3.0.3.2.3. The staff noted that the Open-Cycle Cooling Water System program proposes to manage the aging of carbon steel piping through the use of ultrasonic testing inspections in conjunction with scans using low-frequency electromagnetic technique measurements. In its review of components associated with item 3.3.1-126 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Open-Cycle Cooling Water System program acceptable because it uses similar inspection

techniques as those recommended by the Flow-Accelerated Corrosion program, and these techniques are capable of detecting wall thinning due to erosion.

The staff concludes that for LRA item 3.3.1-126, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.1.18 Hardening and Loss of Strength Due to Elastomer Degradation; and Loss of Material Due to Erosion

LRA Table 3.3-1, item 3.3.1-32a, as amended by letter dated February 14, 2014 (LRA Amendment 31), addresses elastomer seals and components exposed to raw water which will be managed for hardening, loss of strength, and loss of material. 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 effects for elastomer expansion joints exposed to raw water in the circulating water system. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure these effects are adequately managed for safety-related service water system components, as defined by GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment." However, the staff noted that, because the subject components are safety-related service water system components, GALL Report AMP XI.M20 is not applicable.

The staff's evaluation of the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is documented in SER Section 3.0.3.2.12. The staff noted that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program proposes to manage the aging of elastomer expansion joints through the use of visual inspections augmented by physical manipulation, performed during surveillances and maintenance activities when the surfaces are made available. Also, at a minimum, in each 10-year period during the period of extended operation, a representative sample of the inspection population is inspected. In its review of components associated with item 3.3.1-32a, 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 program proposed in the LRA visual examination and physical manipulation, which are capable of identifying hardening and loss of strength of elastomer components, consistent with GALL Report guidance.

3.3.2.1.19 Loss of Coating Integrity

LRA Table 3.3-1, item 3.3.1-128a, as amended by letter dated April 23, 2014, addresses carbon steel heat exchangers, strainers, piping, and tanks, (with coating or lining), exposed to raw water which will be managed for loss of coating integrity. For the AMR items that cite generic note E, the LRA credits the Open-Cycle Cooling Water System, Fire Water System, Fuel Oil Chemistry, or Inspection of Internal Surfaces in Miscellaneous Piping Ducting Components Programs to manage this aging effect.

The staff's evaluation of the acceptability of using the Open-Cycle Cooling Water System, Fire Water System, Fuel Oil Chemistry, and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Programs to manage loss of coating integrity is documented in SER Section 3.0.3.4.

The staff concludes that for LRA item 3.3.1-128a the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.20 Loss of Material due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion, and Fouling that Leads to Corrosion

By letter dated August 2, 2013, the applicant amended LRA Table 3.3-1, item 3.3.1-64 to address steel and copper alloy, piping, piping components, and piping elements exposed to raw water which will be managed for loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion, and fouling that leads to corrosion. For the AMR item that cites generic note E, the LRA credits the External Surfaces Monitoring of Mechanical Components program to manage the aging effect for gray cast iron pumps exposed on the external surfaces to raw water. The GALL Report recommends GALL Report AMP XI.M27, "Fire Water System," to ensure that these aging effects are adequately managed. LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," revised the recommendations in AMP XI.M27. LR-ISG-2012-02 recommends using periodic external visual inspections to ensure that the system maintains its intended function.

The staff's evaluation of the applicant's External Surfaces Monitoring of Mechanical Components program is documented in SER Section 3.0.3.1.10. The accessibility of the pumps was not clear to the staff; however, during conference calls held on October 2 and 3, 2013, the applicant confirmed that the pumps are normally accessible. The staff noted that the External Surfaces Monitoring of Mechanical Components program proposes to manage the aging of gray cast iron pumps through the use of periodic external visual examinations and that inspections are conducted at least every refueling outage. The program also states that the inspection parameters include material condition, which consists of evidence of corrosion, corrosion stains, material wastage, and wear.

In its review of components associated with item 3.3.1-64 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the External Surfaces Monitoring of Mechanical Components program acceptable because periodic visual inspections are conducted which are capable of detecting loss of material and fouling that leads to corrosion.

The staff concludes that for LRA Item 3.3.1-64, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation is Recommended

In LRA Section 3.3.2.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the auxiliary systems components and provides information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- cracking due to SCC and cyclic loading
- cracking due to SCC

- loss of material due to cladding breach
- loss of material due to pitting and crevice corrosion
- QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluations 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 3.3.2.2. The staff's review of the applicant's further evaluation follows.

3.3.2.2.1 Cumulative Fatigue Damage

LRA Section 3.3.2.2.1, associated with LRA Table 3.3-1, items 3.3.1-1 and 3.3.1-2, addresses how steel cranes structural girders exposed to air and steel and stainless steel piping, piping components, piping elements, and heat exchanger components exposed to air-indoor uncontrolled, treated borated water or treated water are being managed for cumulative fatigue damage. The applicant addressed the further evaluation criteria of the SRP-LR by stating that fatigue is a TLAA, as defined in 10 CFR 54.3, and is required to be evaluated in accordance with 10 CFR 54.21(c). The applicant stated that fatigue TLAA identified for ASME Code Section III, Class 2 and 3, and ANSI B31.1 piping are discussed in LRA Section 4.3, and the evaluation of crane load cycles as a TLAA is discussed in LRA Section 4.7.

The staff reviewed LRA Section 3.3.2.2.1 against the criteria in SRP-LR Section 3.3.2.2.1, which states that fatigue of these auxiliary system components is a TLAA as defined in 10 CFR 54.3, and that these TLAAs are to be evaluated in accordance with the TLAA acceptance criteria requirements in 10 CFR 54.21(c)(1). The staff reviewed the applicant's AMR items and determined that the AMR results are consistent with the recommendations of the GALL Report and SRP-LR for managing cumulative fatigue damage in steel cranes structural girders exposed to air-indoor uncontrolled (external), and steel and stainless steel piping, piping components, piping elements, and heat exchanger components exposed to air-indoor uncontrolled, treated borated water or treated water, except as identified below.

The staff also identified that the applicant did not include the applicable AMR items in LRA Table 2s (Tables 3.x.2-y) for the TLAAs associated with fatigue of certain non-Class 1 piping such as those in the boron recycle system and condensate system. Therefore, by letter dated September 6, 2012, as part of RAI 4.3-10, the staff requested the applicant to justify this discrepancy. In its response dated October 11, 2012, the applicant revised LRA Section 3.3 to include additional AMR items for those SSCs subject to an AMR in accordance with 10 CFR 54.21(a)(1), that were not identified previously. The details of RAI 4.3-10 and the staff's evaluation of the applicant's response are documented in SER Section 4.3.5.2.

Based on its review, the staff concludes that the applicant has met the SRP-LR Section 3.3.2.2.1 criteria. For those items that apply to LRA Section 3.3.2.2.1, the staff determined that the LRA is consistent with the GALL Report and that the applicant 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). SER Sections 4.3 and 4.7 document the staff's review of the applicant's evaluation of the TLAA for these components.

3.3.2.2.2 Cracking Due to Stress Corrosion Cracking and Cyclic Loading

LRA Section 3.3.2.2.2, associated with LRA Table 3.3-1, item 3.3.1-3, addresses stainless steel components in the letdown heat exchanger that are exposed to treated borated water which will be managed for cracking due to SCC and cyclic loading by the Water Chemistry and One-Time Inspection Programs. The criteria in SRP-LR Section 3.3.2.2.2 states that cracking caused by SCC and cyclic loading could occur for stainless steel PWR non-regenerative heat exchanger components exposed to treated borated water greater than 60 °C (140 °F) in the CVC system. The SRP-LR also states that the Water Chemistry Program relies on monitoring and control of water chemistry to manage aging effects of cracking due to SCC; however, control of water chemistry does not preclude cracking due to SCC and cyclic loading. The GALL Report recommends that a plant-specific AMP be evaluated to confirm that cracking does not occur, and that an acceptable confirmation 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 plant instrumentation continuously monitors temperature and radioactivity of the shell-side for the letdown (non-regenerative) heat exchanger. The applicant also stated that the sample selection for the One-Time Inspection Program will include heat exchanger tubes with similar materials, environment, and fluid temperatures, and that eddy current testing will be performed.

The staff's evaluations of the applicant's Water Chemistry and One-Time Inspection Programs are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.8, respectively. In its review of components associated with item 3.3.1-3, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the above programs is acceptable because the Water Chemistry Program maintains contaminants at a level to minimize cracking. In addition, the staff notes that the applicant's sample selection for the One-Time Inspection Program, which will confirm the effectiveness of the Water Chemistry Program, will include comparable heat exchanger tubes and will perform eddy current testing which can detect cracking. The staff also notes that plant instrumentation continuously monitors temperature and radioactivity, which is consistent with the recommendations in the SRP-LR and GALL Report.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.2 criteria. For those items associated with LRA Section 3.3.2.2.2, 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 manages so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CRF 54.21(a)(3).

3.3.2.2.3 Cracking Due to Stress Corrosion Cracking

LRA Section 3.3.2.2.3, which is associated with LRA Table 3.3-1, item 3.3.1-4, addresses stainless steel piping, piping components, piping elements and tanks exposed to air - outdoor. The applicant stated this item is not applicable because there are no in-scope stainless steel piping, piping components, piping elements or tanks exposed to air - outdoor in the auxiliary systems. The staff reviewed the applicant's FSAR and LRA Sections 3.3 and 2.3.3 and finds that no in-scope stainless steel piping, piping components, piping elements or tanks exposed to air-outdoor are present in the auxiliary systems. Therefore, the staff finds the applicant's determination acceptable.

3.3.2.2.4 Loss of Material Due to Cladding Breach

LRA Section 3.3.2.2-4, associated with LRA Table 3.3-1, item 3.3.1-5, addresses loss of material due to cladding breach in steel with stainless steel or nickel-alloy cladding pump casings exposed to treated borated water. The applicant stated that this item is not applicable because there are no in-scope steel with stainless steel or nickel-alloy cladding pump casings exposed to treated borated water in the CVC system. The staff reviewed LRA Sections 2.3.3 and 3.3, and FSAR Section 9.0 SP and finds that no in-scope steel with stainless steel or nickel-alloy cladding pump casings exposed to treated borated water are present in the auxiliary systems. Therefore, the staff finds the applicant's determination acceptable.

3.3.2.2.5 Loss of Material due to Pitting and Crevice Corrosion

LRA Section 3.3.2.2.5, associated with LRA Table 3.3-1, item 3.3.1-6, addresses stainless steel piping, piping components, piping elements or tanks exposed to air - outdoor. The applicant stated this item is not applicable because there are no in-scope stainless steel piping, piping components, piping elements or tanks exposed to air - outdoor in the auxiliary systems. The staff reviewed the applicant's FSAR and LRA Sections 3.3 and 2.3.3 finds that no in-scope stainless steel piping, piping components, piping elements, or tanks exposed to air-outdoor are present in the auxiliary systems. Therefore, the staff finds the applicant's determination acceptable.

3.3.2.2.6 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA Program.

3.3.2.2.7 Operating Experience

SER Section 3.0.5, "Operating Experience for Aging Management Programs," documents the staff's evaluation of the applicant's consideration of operating experience of aging management programs.

3.3.2.2.8 Loss of Material Due to Recurring Internal Corrosion

LRA Section 3.3.2.2.8, as modified through LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion under Insulation," is associated with LRA Table 3.3-1, item 3.3.1-127, and addresses loss of material due to recurring internal corrosion in metallic piping, piping components, and tanks exposed to raw water or waste water. By letter dated October 7, 2013, the staff issued RAI 3.0.3-1 requesting the applicant to address issues related to recurring internal corrosion that are addressed by the new SRP-LR Section 3.3.2.2.8. In its response dated December 20, 2013, the applicant stated that the current Open-Cycle Cooling Water System program includes activities to address recurring internal corrosion due to microbiologically influenced corrosion (MIC) in the essential service water system. The applicant stated that the Open-Cycle Cooling Water System program uses a low-frequency electromagnetic technique to screen large areas to detect changes in piping wall thickness, then follows up with ultrasonic measurements to determine pipe wall thickness for any thinned areas. The applicant further stated that the Open-Cycle Cooling Water System program performs opportunistic visual inspections whenever the essential service water system is opened for maintenance. The response also includes a commitment to select an inspection technique to identify internal pipe wall degradation due to MIC for a one-time inspection of buried carbon steel piping, which is representative of other accessible carbon steel piping segments. Although not included in its discussion for this

section, in the response to RAI 3.0.3-1, item a, the applicant reiterated the staff's position that noted that SER Section 3.0.3.2.7 addresses how recurring internal corrosion due to MIC will be managed on the internal surfaces of the fire water system piping.

The staff finds the applicant's response acceptable because, as documented in SER Sections 3.0.3.2.3 and 3.0.3.2.7, the staff evaluated the alternate examination methods, augmented inspections, and additional trending parameters in the existing Open-Cycle Cooling Water System and Fire Water System programs. Based on the above finding, in its review of components associated with item 3.3.1-127, the staff also finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage the effects of aging using the Open-Cycle Cooling Water System and Fire Water System programs is acceptable to address recurring internal corrosion due to MIC. The staff noted that its independent search of plant-specific operating experience during the AMP audit did not identify instances that warranted augmenting any other AMPs that manage components in auxiliary systems to address internal corrosion.

3.3.2.3 AMR Results 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 the AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.3.2-1 through 3.3.2-28, the applicant indicated, via notes F through J, that the combination of component type, material, environment, and AERM does not correspond to an AMR 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 AMR item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the AMR item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

3.3.2.3.1 Auxiliary Systems—Summary of Aging Management Evaluation—Fuel Storage and Handling System—LRA Table 3.3.2-1

The staff reviewed LRA Table 3.3.2-1, which summarizes the results of AMR evaluations for the fuel storage and handling system component groups.

Carbon Steel Crane Components Exposed to Plant Indoor Air (External). In LRA Table 3.3.2-1, the applicant stated that there is a TLAA for the carbon steel crane components exposed to plant indoor air (external), which cites generic note H. The staff confirmed that there is a TLAA, as documented in LRA Section 4.7.1, for this component and material. The staff's evaluation of the TLAA for steel cranes components is documented in SER Section 4.7.1.

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

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

The staff reviewed LRA Table 3.3.2-2, which summarizes the results of AMR evaluations for the fuel pool cooling and cleanup system component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the fuel pool cooling and cleanup system component groups are consistent with the GALL Report.

3.3.2.3.3 Auxiliary Systems—Summary of Aging Management Evaluation—Cranes, Hoists, and Elevators—LRA Table 3.3.2-3

The staff reviewed LRA Table 3.3.2-3, which summarizes the results of AMR evaluations for the cranes, hoists, and elevators component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the cranes, hoists, and elevators component groups are consistent with the GALL Report.

3.3.2.3.4 Auxiliary Systems—Summary of Aging Management Evaluation—Essential Service Water System—LRA Table 3.3.2-4

The staff reviewed LRA Table 3.3.2-4, which summarizes the results of AMR evaluations for the ESW system component groups.

HDPE Piping Exposed to Plant Indoor Air. In LRA Table 3.3.2-4, the applicant stated that for HDPE piping exposed to plant indoor air, there is no aging effect and no AMP is proposed. The AMR item cites generic note G. The AMR item cites plant specific note 3 which states the following:

> HDPE components in a plant indoor air environment are not exposed to an aggressive chemical environment that would concentrate contaminants and degrade HDPE chemical and mechanical properties. HDPE is not exposed to ozone, ionizing radiation or a UV source (sunlight or fluorescent light) that would result in aging. Operating temperatures do not exceed 140 °F. HDPE components in a plant indoor air environment have no aging effects requiring aging management.

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 GALL Report items AP-268 and SP-152, which state that polyvinyl chloride (PVC) piping exposed to uncontrolled indoor air has no AERM or recommended AMP. The HDPE piping's resistance to aging effects is similar to that of PVC, except HDPE is more susceptible to sunlight UV exposure. Given that the applicant has stated that the piping is not exposed to ionizing radiation or a UV source (sunlight or fluorescent light), the staff finds the applicant's determination that there are no AERM acceptable.

Cellulose Silica Cement Splash Panels Exposed to Raw Water (External). In LRA Table 3.3.2-4, the applicant stated that cellulose silica cement splash panels exposed to raw water (external) will be managed for cracking and changes in material properties by the External Surfaces Monitoring of Mechanical Components Program. The AMR item cites generic note F.

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 GALL Report, in item VII.C1.AP-155, states that asbestos cement piping exposed to raw water is susceptible to cracking and changes in material properties. The staff noted that asbestos cement and cellulose silica cement are both cementitous materials that can be used in the same applications and can be expected to experience the same aging effects. 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 External Surfaces Monitoring of Mechanical Components Program is documented in SER Section 3.0.3.1.10. The staff finds the applicant's proposal to manage aging using the External Surfaces Monitoring of Mechanical Components acceptable because the program includes visual inspections which are capable of detecting cracking and changes in material properties in cementitious materials.

HDPE Piping Exposed to an Underground Environment. In LRA Table 3.3.2-4, the applicant stated that HDPE piping in an underground vault and potentially exposed to an underground environment will be managed for cracking, blistering and change in color by the Buried and Underground Piping and Tanks Program. The AMR item originally cited generic note G. However, in its letter dated December 20, 2013, the applicant stated that use of the Buried and Underground Piping and Tanks Program in this instance is consistent with item 3.3.1-133 of the GALL Report, as revised by License Renewal Interim Staff Guidance LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," citing generic note A. The staff reviewed the associated items in the LRA, and the staff finds the applicant's proposal acceptable because it is consistent with the GALL Report, as revised by LR-ISG-2012-02.

HDPE Piping Exposed to a Buried Environment. In LRA Table 3.3.2-4, the applicant stated there is a TLAA for HDPE piping exposed to a buried environment which cite generic note H. The staff confirmed that there is a TLAA, as documented in LRA Section 4.7, for this component and material. The staff's evaluation of the TLAA for HDPE piping is documented in SER Section 4.7.8.

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

3.3.2.3.5 Auxiliary Systems—Summary of Aging Management Evaluation—Service Water System—LRA Table 3.3.2-5

The staff reviewed LRA Table 3.3.2-5, which summarizes the results of AMR evaluations for the service water system component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment,

and AERM for the service water system component groups are consistent with the GALL Report.

3.3.2.3.6 Auxiliary Systems—Summary of Aging Management Evaluation—Reactor Makeup Water System—LRA Table 3.3.2-6

The staff reviewed LRA Table 3.3.2-6, which summarizes the results of AMR evaluations for the reactor makeup water system component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the reactor makeup water system component groups are consistent with the GALL Report.

3.3.2.3.7 Auxiliary Systems—Summary of Aging Management Evaluation—Component Cooling Water System—LRA Table 3.3.2-7

The staff reviewed LRA Table 3.3.2-7, which summarizes the results of AMR evaluations for the CCW system component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the CCW system component groups are consistent with the GALL Report.

3.3.2.3.8 Auxiliary Systems—Summary of Aging Management Evaluation—Compressed Air System—LRA Table 3.3.2-8`

The staff reviewed LRA Table 3.3.2-8, which summarizes the results of AMR evaluations for the compressed air system component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the compressed air system component groups are consistent with the GALL Report.

3.3.2.3.9 Auxiliary Systems—Summary of Aging Management Evaluation—Nuclear Sampling System—LRA Table 3.3.2-9

The staff reviewed LRA Table 3.3.2-9, which summarizes the results of AMR evaluations for the nuclear sampling system component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the nuclear sampling system component groups are consistent with the GALL Report.

3.3.2.3.10 Auxiliary Systems—Summary of Aging Management Evaluation—Chemical and Volume Control System—LRA Table 3.3.2-10

The staff reviewed LRA Table 3.3.2-10, which summarizes the results of AMR evaluations for the CVC system component groups.

Carbon Steel Heat Exchangers Exposed to Closed Cycle Cooling Water. In LRA Table 3.3.2-10, the applicant stated there is a TLAA for carbon steel heat exchangers exposed to closed cycle cooling water which cite generic note H. The staff confirmed that there is a TLAA, as documented in LRA Section 4.3.8, for this component and material. The staff's evaluation of the fatigue TLAA for ASME Code Class 2 heat exchangers is documented in SER Section 4.3.8.2.

Calcium Silicate Insulation Exposed to Plant Indoor Air. In LRA Tables 3.3.2-10 and 3.3.2-22, as amended by letter dated December 19, 2012, the applicant stated that for calcium silicate insulation exposed to plant indoor air, there is no aging effect and no AMP is proposed. The AMR items originally cited generic note J, indicating that neither the component nor the material and environment are evaluated in the GALL Report.

The staff noted that, subsequent to the applicant's December 19, 2012, LRA amendment, License Renewal Interim Staff Guidance (LR-ISG) LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," was issued, adding SRP-LR item 3.4.1-64 to manage reduced thermal insulation resistance for calcium silicate insulation exposed to plant air using GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components." In LRA Amendment 28, dated December 20, 2013, the applicant revised this item to manage reduced thermal insulation resistance with the External Surfaces Monitoring of Mechanical Components Program, consistent with LR-ISG-2012-02. Therefore, the staff finds the applicant's proposal to manage aging acceptable.

3.3.2.3.11 Auxiliary Systems—Summary of Aging Management Evaluation—Control 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 control building HVAC system component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the control building HVAC system component groups are consistent with the GALL Report.

3.3.2.3.12 Auxiliary Systems—Summary of Aging Management Evaluation—Essential Service Water Pumphouse HVAC System—LRA Table 3.3.2-12

The staff reviewed LRA Table 3.3.2-12, which summarizes the results of AMR evaluations for the ESW pumphouse HVAC system component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the essential service water pumphouse HVAC system component groups are consistent with the GALL Report.

3.3.2.3.13 Auxiliary Systems—Summary of Aging Management Evaluation—Auxiliary Building HVAC System—LRA Table 3.3.2-13

The staff reviewed LRA Table 3.3.2-13, which summarizes the results of AMR evaluations for the auxiliary building HVAC system component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the auxiliary building HVAC system component groups are consistent with the GALL Report.

3.3.2.3.14 Auxiliary Systems—Summary of Aging Management Evaluation—Fuel Building HVAC System—LRA Table 3.3.2-14

The staff reviewed LRA Table 3.3.2-14, which summarizes the results of AMR evaluations for the fuel building HVAC system component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the fuel building HVAC system component groups are consistent with the GALL Report.

3.3.2.3.15 Auxiliary Systems—Summary of Aging Management Evaluation—Miscellaneous 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 miscellaneous building HVAC system component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the miscellaneous building HVAC system component groups are consistent with the GALL Report.

3.3.2.3.16 Auxiliary Systems—Summary of Aging Management Evaluation—Diesel Generator Building HVAC System—LRA Table 3.3.2-16

The staff reviewed LRA Table 3.3.2-16, which summarizes the results of AMR evaluations for the diesel generator building HVAC system component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the diesel generator building HVAC system component groups are consistent with the GALL Report.

3.3.2.3.17 Auxiliary Systems—Summary of Aging Management Evaluation—Radwaste Building HVAC System—LRA Table 3.3.2-17

The applicant removed this system from within the scope of license renewal by letter dated February 14, 2014. The staff reviewed this removal as discussed in SER Section 2.3.3.17 and finds it acceptable; therefore, no AMR items are associated with this system for review.

3.3.2.3.18 Auxiliary Systems—Summary of Aging Management Evaluation—Turbine Building HVAC System—LRA Table 3.3.2-18

The staff reviewed LRA Table 3.3.2-18, which summarizes the results of AMR evaluations for the turbine building HVAC system component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the turbine building HVAC system component groups are consistent with the GALL Report.

3.3.2.3.19 Auxiliary Systems—Summary of Aging Management Evaluation—Containment Cooling System—LRA Table 3.3.2-19

The staff reviewed LRA Table 3.3.2-19, which summarizes the results of AMR evaluations for the containment cooling system component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the containment cooling system component groups are consistent with the GALL Report.

3.3.2.3.20 Auxiliary Systems—Summary of Aging Management Evaluation—Fire Protection System—LRA Table 3.3.2-20

The staff reviewed LRA Table 3.3.2-20, which summarizes the results of AMR evaluations for the fire protection system component groups.

PVC Piping Exposed to Waste Water. In LRA Table 3.3.2-20, the applicant stated that for PVC piping exposed to waste water, there is no aging effect and no AMP is proposed. The AMR item cites generic note G. The AMR item cites plant-specific note 2 which states, "PVC in a

wastewater environment is unaffected by water, concentrated alkalis, non-oxidizing acids, oils, ozone, or humidity changes. PVC in a waste water environment is not exposed to direct sunlight or ionizing radiation. Therefore PVC in a wastewater environment has no aging effect."

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 PCV Pipe – Design and Installation – Manual of Water Supply Practices, M23, American Water Works Association, Second Edition, 2002, states, in part, the following:

> PVC and PVCO pipes are resistant to almost all types of corrosion-both chemical and electrochemical-that are experienced in underground piping systems. Because PVC is a nonconductor, galvanic and electrochemical effects are nonexistent in PVC piping systems. PVC pipe cannot be damaged by aggressive waters or corrosive soils. …
>
> PVC pipe is nearly totally resistant to biological attack. Biological attack can be described as degradation or deterioration caused by the action of living microorganisms or macroorganisms. …
>
> PVC pipe is well suited to applications where abrasive conditions are anticipated.

Appendix A, Chemical Resistance Tables of this document lists PVC as generally resistant to chemicals up to 140 °F, such as bleach (12.5 percent active chlorine), potassium hydroxide, sodium hydroxide, kerosene, hydrochloric acid, hydrogen peroxide (90 percent), sea water, soaps, and sulfuric acid (70 percent). The staff also noted that PVC Formulary, G Wypych, Chem Tec Publishing, 2009 states, "[a]s a general rule, PVC is not resistant to polar solvents but very resistant to acids, bases, salts, alcohols, esters, and hydrocarbons." Based on its review of the LRA and the above documents, the staff finds the applicant's proposal that there's no AERM for PVC piping exposed to waste water acceptable because, (a) PVC is resistant to acids and bases which could be found in fire protection waste water piping, (b) polar solvents (e.g., toluene, turpentine, acetone) would not be expected to be present in this piping, and (c) PVC piping is not exposed to direct sunlight or ionizing radiation.

On the basis of its review, the staff concludes for items in LRA Table 3.3.2-20 with no AERMs, that the applicant has appropriately evaluated the material and environment combinations not addressed in the GALL Report, and their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.21 Auxiliary Systems—Summary of Aging Management Evaluation—Emergency Diesel Engine Fuel Oil Storage and Transfer System—LRA Table 3.3.2-21

The staff reviewed LRA Table 3.3.2-21, which summarizes the results of AMR evaluations for the emergency diesel engine fuel oil storage and transfer system component groups.

Carbon Steel Closure Bolting Exposed to an Underground Environment. In LRA Table 3.3.2-21, as amended by letter dated August 29, 2013, the applicant stated that carbon steel closure bolting exposed to an underground environment will be managed for loss of preload by the Bolting Integrity Program. The AMR item cites generic note G.

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 the applicant addressed loss of material for this component, material, and environment combination in another AMR item in LRA

Table 3.3.2-21. Based on its review of the GALL Report, which recommends that steel bolting exposed to outdoor air (a similar environment to the underground environment due to having the potential for exposure to moisture) be managed for loss of material and loss of preload, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination. The staff noted that high-strength carbon steel bolts (actual yield strengths of at least 150 ksi) can also be susceptible to cracking; however, LRA Section B2.1.8 states that no high-strength bolting is used in pressure-retaining joints within the scope of the Bolting Integrity Program.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.2. The staff noted that the program proposes to manage loss of preload by preventive actions, including the use of appropriate lubricants and sealants, selection of bolting material with appropriate yield strength, and application of appropriate preload. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the preventive actions described above minimize the potential for loss of preload, consistent with the GALL Report guidance.

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

3.3.2.3.22 Auxiliary Systems—Summary of Aging Management Evaluation—Standby Diesel Generator Engine System—LRA Table 3.3.2-22

The staff reviewed LRA Table 3.3.2-22, which summarizes the results of AMR evaluations for the standby diesel generator engine system component groups.

Calcium Silicate Insulation Exposed to Plant Indoor Air. The staff's evaluation for calcium silicate insulation exposed to plant indoor air, for which the applicant cited no aging effect and no proposed AMP, but subsequently revised to be consistent with the GALL Report, is documented in SER Section 3.3.2.3.10.

Carbon Steel Piping Exposed to Diesel Exhaust. In LRA Table 3.3.2-22, the applicant stated there is a TLAA for carbon steel piping exposed to diesel exhaust which cite generic note H. The staff confirmed that there is a TLAA, as documented in LRA Section 4.3.5, for this component and material. The staff's evaluation of the fatigue TLAA for ANSI B31.1 and ASME Code Section III Class 2 and 3 piping is documented in SER Section 4.3.5.2.

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

3.3.2.3.23 Auxiliary Systems—Summary of Aging Management Evaluation—EOF and TSC Diesels, Security Building System—LRA Table 3.3.2-23

The staff reviewed LRA Table 3.3.2-23, which summarizes the results of AMR evaluations for the EOF and TSC diesels, security building system component groups.

Elastomeric Flexible Hoses and Expansion Joints Exposed to Fuel Oil (Internal) and Demineralized Water (Internal). In LRA Tables 3.3.2-23 and 3.3.2-28, the applicant stated that the internal surfaces of elastomeric flexible hoses and expansion joints exposed to fuel oil and 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 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. The staff noted that the applicant's identified aging effects and its aging management approach is consistent with the GALL Report guidance for elastomers exposed to wet environments. GALL Report item VII.C2.AP-259 recommends that elastomeric components exposed to closed-cycle cooling water be managed for hardening and loss of strength with GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components." The staff also noted that another potential aging effect, loss of material due to wear or erosion, would not be expected to be applicable to the internal surfaces of the subject hoses and expansion joints. The internal surfaces of these components are not expected to experience relative motion contact that could lead to wear, and the fuel oil and demineralized water environments are controlled to minimize particulates. Based on its review of GALL Report Sections IX.E, "Selected Use of Terms for Describing and Standardizing Aging Effects," and IX.F, "Significant Aging Mechanisms," which identify hardening, loss of strength, and loss of material as the only applicable aging effects for elastomeric components, 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 3.0.3.2.12. 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 this program includes opportunistic visual and physical manipulation inspections of elastomeric materials that are capable of detecting hardening and loss of strength.

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

3.3.2.3.24 Auxiliary Systems—Summary of Aging Management Evaluation—Liquid Radwaste System—LRA Table 3.3.2-24

The staff reviewed LRA Table 3.3.2-24, which summarizes the results of AMR evaluations for the liquid radwaste system component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the liquid radwaste system component groups are consistent with the GALL Report.

3.3.2.3.25 Auxiliary Systems—Summary of Aging Management Evaluation—Decontamination System—LRA Table 3.3.2-25

The staff reviewed LRA Table 3.3.2-25, which summarizes the results of AMR evaluations for the decontamination system component groups. The staff's review did not identify any AMR

items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the decontamination system component groups are consistent with the GALL Report.

3.3.2.3.26 Auxiliary Systems—Summary of Aging Management Evaluation—Oily Waste 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 oily waste system component groups.

Carbon Steel and Stainless Steel Closure Bolting Exposed to Waste Water. In LRA Tables 3.3.2-26 and 3.3.2-27, the applicant stated that carbon steel and stainless steel closure bolting exposed to waste water will be managed for loss of preload by the Bolting Integrity 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. The staff noted that the applicant addressed loss of material for this component, material, and environment combination in other AMR items in LRA Tables 3.3.2-26 and 3.3.2-27. Based on its review of the GALL Report, which recommends that steel and stainless steel bolting exposed to raw water (a similar environment to waste water) be managed for loss of material and loss of preload, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination. The staff noted that high-strength carbon steel bolts (actual yield strengths of at least 150 ksi) can also be susceptible to cracking; however, LRA Section B2.1.8 states that no high-strength bolting is used in pressure-retaining joints within the scope of the Bolting Integrity Program.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.2. The staff noted that the program proposes to manage the aging of submerged bolting by preventive actions, including proper torqueing of bolts and checking for uniformity of gasket compression. In addition, the insights into loss of preload are obtained by (a) monitoring of the waste water sumps during operator rounds to confirm that they are being drained, which may detect bolt loosening that would be manifested in abnormal pump performance, and (b) visual inspections of the bolts when the pumps are dewatered, but at least once every four refueling outages. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the preventive actions minimize the potential for loss of preload, and the pump performance monitoring and visual inspections are capable of detecting loss of preload prior to loss of intended functions.

Gray Cast Iron Valves (Internally) and Pumps (Internally and Externally) Exposed to Waste Water. In LRA Table 3.3.2-26, the applicant stated that gray cast iron valves, internally exposed, and pumps internally and externally exposed to waste water will be managed for loss of material by the Selective Leaching Program. The AMR items previously cited generic note G and plant-specific note 3, which states that gray cast iron SSCs with surfaces exposed to waste water are subject to loss of material due to selective leaching. However, in a letter dated December 20, 2013, the applicant revised this section to state that the use of the Selective Leaching Program is consistent with item 3.3.1-72 of the GALL Report, as revised by License Renewal Interim Staff Guidance LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," citing generic note B. The staff reviewed the associated items in the LRA, and the staff finds the applicant's proposal acceptable because it is consistent with the GALL Report, as revised by LR-ISG-2012-02.

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

3.3.2.3.27 Auxiliary Systems—Summary of Aging Management Evaluation—Floor and Equipment Drainage System—LRA Table 3.3.2-27

The staff reviewed LRA Table 3.3.2-27, which summarizes the results of AMR evaluations for the floor and equipment drainage system component groups.

Carbon Steel and Stainless Steel Closure Bolting Exposed to Waste Water. In LRA Table 3.3.2-27, the applicant stated that carbon steel and stainless steel closure bolting exposed to waste water will be managed for loss of preload by the Bolting Integrity 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. The staff noted that the applicant addressed loss of material for this component, material, and environment combination in other AMR items in LRA Tables 3.3.2-26 and 3.3.2-27. Based on its review of the GALL Report, which recommends that steel and stainless steel bolting exposed to raw water (a similar environment to waste water) be managed for loss of material and loss of preload, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination. The staff noted that high-strength carbon steel bolts (actual yield strengths of at least 150 ksi) can also be susceptible to cracking; however, LRA Section B2.1.8 states that no high-strength bolting is used in pressure-retaining joints within the scope of the Bolting Integrity Program.

The staff's evaluation of the applicant's Bolting Integrity Program is documented in SER Section 3.0.3.2.2. The staff noted that the program proposes to manage the aging of submerged bolting by preventive actions, including proper torqueing of bolts and checking for uniformity of gasket compression. In addition, the insights into loss of preload are obtained by (a) monitoring of the waste water sumps during operator rounds to confirm that they are being drained, which may detect bolt loosening that would be manifested in abnormal pump performance, and (b) visual inspections of the bolts when the pumps are dewatered, but at least once every four refueling outages. The staff finds the applicant's proposal to manage aging using the Bolting Integrity Program acceptable because the preventive actions minimize the potential for loss of preload, and the pump performance monitoring and visual inspections are capable of detecting loss of preload prior to loss of intended functions.

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

3.3.2.3.28 Auxiliary Systems—Summary of Aging Management Evaluation—Miscellaneous Systems in scope ONLY for Criterion 10 CFR 54.4(a)(2)—LRA Table 3.3.2-28

The staff reviewed LRA Table 3.3.2-28, which summarizes the results of AMR evaluations for the miscellaneous systems in scope only for criterion 10 CFR 54.4(a)(2) component groups.

Elastomeric Flexible Hoses Exposed to Demineralized Water (Internal). The staff's evaluation for elastomeric flexible hoses exposed to demineralized water (internal), which will be managed for hardening and loss of strength by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program, is documented in SER Section 3.3.2.3.23.

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

3.3.2.3.29 Auxiliary Systems—Summary of Aging Management Evaluation—Circulating Water System—LRA Table 3.3.2-29

The staff reviewed LRA Table 3.3.2-29, as amended by letter dated February 14, 2014, which summarizes the results of AMR evaluations for the circulating water system component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the circulating water system component groups are consistent with the GALL Report.

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 function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4 Aging Management of Steam and Power Conversion Systems

This section of the SER documents the staff's review of the applicant's AMR results for the steam and power conversion system components and component groups of the following systems:

- main turbine system
- main steam supply system
- main feedwater system
- steam generator blowdown system
- auxiliary feedwater system
- condensate storage and transfer system

3.4.1 Summary of Technical Information in the Application

LRA Section 3.4 provides AMR results for the steam and power conversion systems components and component groups. In LRA Table 3.4-1, "Summary of Aging Management Programs 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 systems components and component groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included condition reports and discussions with appropriate site personnel to identify AERMs.

The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.4.2 Staff Evaluation

The staff reviewed LRA Section 3.4 to determine if the applicant provided sufficient information to demonstrate that the effects of aging for 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 function(s) 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 of AMPs to ensure the applicant's claim that certain AMPs were consistent with the GALL Report. The purpose of this audit was to examine the applicant's AMPs and related documentation and to confirm the applicant's claim of consistency with the corresponding GALL Report AMPs. The staff did not repeat its review of the matters described in the GALL Report. The staff's evaluations of the AMPs are documented in SER Section 3.0.3.

The staff reviewed the AMRs to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did confirm that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. Details of the staff's evaluation are discussed in SER Section 3.4.2.1.

During its review, the staff also selected AMRs consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the SRP-LR Section 3.4.2.2 acceptance criteria. The staff's evaluations are documented in SER Section 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.

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.

Table 3.4-1 Staff Evaluation for Steam and Power Conversion Systems Components in the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	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 caused by fatigue	Fatigue is a time-limited aging analysis (TLAA) to be evaluated for the period of extended operation (see SRP, Section 4.3 “Metal Fatigue,” for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1)).	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.4.2.2.1)
Stainless steel Piping, piping components, and piping elements; tanks exposed to Air – outdoor (3.4.1-2)	Cracking caused by stress corrosion cracking	Chapter XI.M36, “External Surfaces Monitoring of Mechanical Components”	Yes	External Surfaces Monitoring of Mechanical Components	Consistent with the GALL Report (see SER Section 3.4.2.2.2)
Stainless steel Piping, piping components, and piping elements; tanks exposed to Air – outdoor (3.4.1-3)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M36, “External Surfaces Monitoring of Mechanical Components”	Yes	External Surfaces Monitoring of Mechanical Components and Aboveground Metallic Tanks (for CST only)	Consistent with the GALL Report (see SER Section 3.4.2.2.3)
Steel External surfaces, Bolting exposed to Air with borated water leakage (3.4.1-4)	Loss of material caused by boric acid corrosion	Chapter XI.M10, “Boric Acid Corrosion”	No	Boric Acid Corrosion	Consistent with the GALL Report (see SER Section 3.4.2.1.1)
Steel Piping, piping components, and piping elements exposed to Steam, Treated water (3.4.1-5)	Wall thinning caused by flow-accelerated corrosion	Chapter XI.M17, “Flow-Accelerated Corrosion”	No	Flow-Accelerated Corrosion	Consistent with the GALL Report
Steel, Stainless Steel Bolting exposed to Soil (3.4.1-6)	Loss of preload	Chapter XI.M18, “Bolting Integrity “	No	Not applicable	Not applicable to Callaway(see SER Section 3.4.2.1.1)
High-strength steel Closure bolting exposed to Air with steam or water leakage (3.4.1-7)	Cracking caused by cyclic loading, stress corrosion cracking	Chapter XI.M18, “Bolting Integrity”	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel; stainless steel Bolting, Closure bolting exposed to Air – outdoor (External), Air – indoor, uncontrolled (External) (3.4.1-8)	Loss of material caused by general (steel only), pitting, and crevice corrosion	Chapter XI.M18, “Bolting Integrity”	No	Bolting Integrity	Consistent with the GALL Report
Steel Closure bolting exposed to Air with steam or water leakage (3.4.1-9)	Loss of material caused by general corrosion	Chapter XI.M18, “Bolting Integrity”	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Copper alloy, Nickel alloy, Steel; stainless steel, Steel; stainless steel Bolting, Closure bolting exposed to Any environment, Air – outdoor (External), Air – indoor, uncontrolled (External) (3.4.1-10)	Loss of preload caused by thermal effects, gasket creep, and self-loosening	Chapter XI.M18, “Bolting Integrity”	No	Bolting Integrity	Consistent with the GALL Report
Stainless steel Piping, piping components, and piping elements, Tanks, Heat exchanger components exposed to Steam, Treated water >60 °C (>140 °F) (3.4.1-11)	Cracking caused by stress corrosion cracking	Chapter XI.M2, “Water Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report
Steel; stainless steel Tanks exposed to Treated water (3.4.1-12)	Loss of material caused by general (steel only), pitting, and crevice corrosion	Chapter XI.M2, “Water Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Steel Piping, piping components, and piping elements exposed to Treated water (3.4.1-13)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M2, “Water Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report
Steel Piping, piping components, and piping elements, PWR heat exchanger components exposed to Steam, Treated water (3.4.1-14)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M2, “Water Chemistry,” and Chapter XI.M32, “One-Time Inspection”	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel Heat exchanger components exposed to Treated water (3.4.1-15)	Loss of material caused by general, pitting, crevice, and galvanic corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Copper-alloy, Stainless steel, Nickel alloy, Aluminum Piping, piping components, and piping elements, Heat exchanger components and tubes, PWR heat exchanger components exposed to Treated water, Steam (3.4.1-16)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report
Copper-alloy Heat exchanger tubes exposed to Treated water (3.4.1-17)	Reduction of heat transfer caused by fouling	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Copper alloy, Stainless steel Heat exchanger tubes exposed to Treated water (3.4.1-18)	Reduction of heat transfer caused by fouling	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report
Stainless steel, Steel Heat exchanger components exposed to Raw water (3.4.1-19)	Loss of material caused by general, pitting, crevice, galvanic, and microbiologically -influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Copper-alloy, Stainless steel Piping, piping components, and piping elements exposed to Raw water (3.4.1-20)	Loss of material caused by pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel Heat exchanger components exposed to Raw water (3.4.1-21)	Loss of material caused by pitting, crevice, and microbiologically -influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Stainless steel, Copper alloy, Steel Heat exchanger tubes, Heat exchanger components exposed to Raw water (3.4.1-22)	Reduction of heat transfer caused by fouling	Chapter XI.M20, “Open-Cycle Cooling Water System”	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Stainless steel Piping, piping components, and piping elements exposed to Closed-cycle cooling water >60 °C (>140 °F) (3.4.1-23)	Cracking caused by stress corrosion cracking	Chapter XI.M21A, “Closed Treated Water Systems”	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Steel Heat exchanger components exposed to Closed-cycle cooling water (3.4.1-24)	Loss of material caused by general, pitting, crevice, and galvanic corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Steel Heat exchanger components exposed to Closed-cycle cooling water (3.4.1-25)	Loss of material caused by general, pitting, crevice, and galvanic corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Stainless steel Heat exchanger components, Piping, piping components, and piping elements exposed to Closed-cycle cooling water (3.4.1-26)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Copper-alloy Piping, piping components, and piping elements exposed to Closed-cycle cooling water (3.4.1-27)	Loss of material caused by pitting, crevice, and galvanic corrosion	Chapter XI.M21A, “Closed Treated Water Systems”	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel, Stainless steel, Copper alloy Heat exchanger components and tubes, Heat exchanger tubes exposed to Closed-cycle cooling water (3.4.1-28)	Reduction of heat transfer caused by fouling	Chapter XI.M21A, "Closed Treated Water Systems"	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Steel Tanks exposed to Air – outdoor (External) (3.4.1-29)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M29, "Aboveground Metallic Tanks"	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Steel, Stainless Steel, Aluminum Tanks (within the scope of Chapter XI.M29, "Aboveground Metallic Tanks") exposed to Soil or Concrete, or the following external environments air-outdoor, air-indoor uncontrolled, moist air, condensation (3.4.1-30)	Loss of material due to general (steel only), pitting, and crevice corrosion; cracking due to stress corrosion cracking (stainless steel and aluminum only)	Chapter XI.M29, "Aboveground Metallic Tanks"	No	Aboveground Metallic Tanks	Consistent with the GALL Report
Stainless steel, Aluminum Tanks (within the scope of Chapter XI.M29, "Aboveground Metallic Tanks") exposed to Soil or Concrete or the following external environments air-outdoor, air-indoor uncontrolled, moist air, condensation (3.4.1-31)	Loss of material caused by pitting, and crevice corrosion; cracking due to stress corrosion cracking	Chapter XI.M29, "Aboveground Metallic Tanks"	No	Aboveground Metallic Tanks	Consistent with the GALL Report
Gray cast iron Piping, piping components, and piping elements exposed to Soil (3.4.1-32)	Loss of material caused by selective leaching	Chapter XI.M33, "Selective Leaching"	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Gray cast iron, Copper-alloy (>15% Zn or >8% Al) Piping, piping components, and piping elements exposed to Treated water, Raw water, Closed-cycle cooling water (3.4.1-33)	Loss of material caused by selective leaching	Chapter XI.M33, “Selective Leaching”	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Steel External surfaces exposed to Air – indoor, uncontrolled (External), Air – outdoor (External), Condensation (External) (3.4.1-34)	Loss of material caused by general corrosion	Chapter XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	External Surfaces Monitoring of Mechanical Components	Consistent with the GALL Report
Aluminum Piping, piping components, and piping elements exposed to Air – outdoor (3.4.1-35)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	External Surfaces Monitoring of Mechanical Components	Consistent with the GALL Report
Steel Piping, piping components, and piping elements exposed to Air – outdoor (Internal) (3.4.1-36)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M38, "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 Piping, piping components, and piping elements exposed to Condensation (Internal) (3.4.1-37)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M38, “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 Piping, piping components, and piping elements exposed to Raw water (3.4.1-38)	Loss of material caused by general, pitting, crevice, galvanic, and microbiologically -influenced corrosion; fouling that leads to corrosion	Chapter XI.M38, “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
Stainless steel Piping, piping components, and piping elements exposed to Condensation (Internal) (3.4.1-39)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M38, “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 (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel Piping, piping components, and piping elements exposed to Lubricating oil (3.4.1-40)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis and One-Time Inspection	Consistent with the GALL Report
Steel Heat exchanger components exposed to Lubricating oil (3.4.1-41)	Loss of material caused by general, pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis and One-Time Inspection	Consistent with the GALL Report
Aluminum Piping, piping components, and piping elements exposed to Lubricating oil (3.4.1-42)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Copper-alloy Piping, piping components, and piping elements exposed to Lubricating oil (3.4.1-43)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Stainless steel Piping, piping components, and piping elements, Heat exchanger components exposed to Lubricating oil (3.4.1-44)	Loss of material caused by pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis and One-Time Inspection	Consistent with the GALL Report
Aluminum Heat exchanger components and tubes exposed to Lubricating oil (3.4.1-45)	Reduction of heat transfer caused by fouling	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Stainless steel, Steel, Copper alloy Heat exchanger tubes exposed to Lubricating oil (3.4.1-46)	Reduction of heat transfer caused by fouling	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis and One-Time Inspection	Consistent with the GALL Report
Steel (with coating or wrapping), nickel alloy, Piping, piping components, and piping elements; tanks exposed to Soil or Concrete (3.4.1-47)	Loss of material caused by general, pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Buried and Underground Piping and Tanks	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless Steel, nickel alloy, Bolting exposed to Soil (3.4.1-48)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Stainless steel, nickel alloy, Piping, piping components, and piping elements exposed to Soil or Concrete (3.4.1-49)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Steel Bolting exposed to Soil (3.4.1-50)	Loss of material caused by general, pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Underground Stainless Steel, nickel alloy and Steel Piping, piping components, and piping elements (3.4.1-50a)	Loss of material caused by general (steel only), pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable	Not applicaple to Callaway (see SER Section 3.4.2.1.1)
Steel Piping, piping components, and piping elements exposed to Concrete (3.4.1-51)	None	None, provided 1) attributes of the concrete are consistent with ACI 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG-1557, and 2) plant OE indicates no degradation of the concrete	No, if conditions are met.	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Aluminum Piping, piping components, and piping elements exposed to Gas, Air – indoor, uncontrolled (Internal/External) (3.4.1-52)	None	None	NA - No AEM or AMP	None	Consistent with the GALL Report
Copper-alloy (≤15% Zn and ≤8% Al) piping, piping components, and piping elements exposed to air with borated water leakage (3.4.1-53)	None	None	NA - No AEM or AMP	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper-alloy piping, piping components, and piping elements exposed to gas, air – indoor, uncontrolled (external) (3.4.1-54)	None	None	NA - No AEM or AMP	None	Consistent with the GALL Report
Glass piping elements exposed to lubricating oil, air – outdoor, condensation (internal/external), raw water, treated water, air with borated water leakage, gas, closed-cycle cooling water, air – indoor, uncontrolled (external) (3.4.1-55)	None	None	NA - No AEM or AMP	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Nickel alloy Piping, piping components, and piping elements exposed to Air – indoor, uncontrolled (External) (3.4.1-56)	None	None	NA - No AEM or AMP	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Nickel alloy, PVC Piping, piping components, and piping elements exposed to Air with borated water leakage, Air – indoor, uncontrolled, Condensation (Internal) (3.4.1-57)	None	None	NA - No AEM or AMP	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to air – indoor, uncontrolled (external), concrete, gas, air – indoor, uncontrolled (internal) (3.4.1-58)	None	None	NA - No AEM or AMP	None	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to air – indoor controlled (external), gas (3.4.1-59)	None	None	NA - No AEM or AMP	None	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Any material, piping, piping components, and piping elements exposed to treated water (3.4.1-60)	Wall thinning due to erosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.1.1)
Metallic piping, piping components, and tanks exposed to raw water or waste water (3.4.1-61)	Loss of material due to recurring internal corrosion	A plant-specific aging management program is to be evaluated to address recurring internal corrosion	Yes, plant-specific (see subsection 3.4.2.2.6)	Not applicable	Not applicable to Callaway (see SER Section 3.4.2.2.6)
Steel, stainless steel or aluminum tanks (within the scope of Chapter XI.M29, "Aboveground Metallic Tanks") exposed to treated water (3.4.1-62)	Loss of material due to general (steel only), pitting, and crevice corrosion	Chapter XI.M29, "Aboveground Metallic Tanks"	No	Aboveground Metallic Tanks	Consistent with the GALL Report
Metallic piping, piping components, heat exchangers, tanks with Service Level III (augmented) internal coatings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, or lubricating oil (3.4.1-62a)	Loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage	Chapter XI.M42, "Service Level III (augmented) Coatings Monitoring and Maintenance Program"	No	Not applicable	Consistent with the GALL Report (see SER Section 3.4.2.1.1)
Insulated steel, stainless steel, copper alloy, aluminum, or copper alloy (>15% Zn) piping, piping components, and tanks exposed to condensation, air-outdoor (3.4.1-63)	Loss of material due to general (steel, and copper alloy), pitting, or crevice corrosion, and cracking due to stress corrosion cracking (aluminum, stainless steel and copper alloy (>15% Zn) only)	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components" or Chapter XI.M29, "Aboveground Metallic Tanks" (for tanks only)	No	External Surfaces Monitoring of Mechanical Components or Aboveground Metallic Tanks (for tanks only)	Consistent with the GALL Report
Jacketed calcium silicate or fiberglass insulation in an air-indoor uncontrolled or air-outdoor environment (3.4.1-64)	Reduced thermal insulation resistance due to moisture intrusion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring of Mechanical Components	Consistent with the GALL Report (see SER Sections 3.2.2.3.6, 3.3.2.3.10, and 3.4.2.3.2)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Jacketed Foamglas® (glass dust) insulation in an air-indoor uncontrolled or air-outdoor environment (3.4.1-65)	Reduced thermal insulation resistance due to moisture intrusion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Aboveground Metallic Tanks	Consistent with the GALL Report (see SER Section 3.4.2.1.2)

3.4.2.1 AMR Results Consistent with the GALL Report

LRA Section 3.4.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the steam and power conversion systems components:

- Aboveground Metallic Tanks
- Bolting Integrity
- Buried and Underground Piping and Tanks
- External Surfaces Monitoring of Mechanical Components
- 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 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 claimed consistency and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine if the plant-specific components in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR item. 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–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 AMR 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.

3.4.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.4-1, items 3.4.1-6, 3.4.1-7, 3.4.1-12, 3.4.1-15, 3.4.1-17, 3.4.1-19 through 3.4.1-29, 3.4.1-32, 3.4.1-33, 3.4.1-42, 3.4.1-43, 3.4.1-45, 3.4.1-48, 3.4.1-49, 3.4.1-50, 3.4.1-51, 3.4.1-56, 3.4.1-57, and 3.4.1-62a, the applicant claimed that the corresponding items in the GALL Report are not applicable because the component, material, and environment combination described in the SRP-LR does not exist for in-scope SCs at Callaway. The staff reviewed the LRA and FSAR and confirmed that the applicant's LRA does not have any AMR results applicable for these items.

For LRA Table 3.4-1 items discussed below, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable; however, the staff non-applicability verification of these items required the review of sources beyond the LRA and FSAR, and/or the issuance of RAIs.

LRA Table 3.4-1, item 3.4.1-4 addresses steel external surfaces and bolting exposed to air with borated water leakage. The GALL Report recommends GALL Report AMP XI.M10, "Boric Acid Corrosion," to manage loss of material caused by boric acid corrosion for this component group. In the original LRA, the applicant stated that this item was not applicable; however, in LRA Amendment No. 1 dated April 25, 2012, the applicant revised the LRA to state that the item was applicable and consistent with the GALL Report guidance. The applicant also added AMR items that reference LRA item 3.4.1-4. The staff reviewed the associated AMR items,

which cite generic note A, and confirmed the applicant's claim of consistency with the GALL Report.

LRA Table 3.4-1, item 3.4.1-9 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 caused by general corrosion for this component group. The applicant stated that this item is not applicable because closure bolting was evaluated using plant indoor air as the external environment and SRP-LR Table 3.4-1, item 3.4.1-8 for steel closure bolting exposed to an air-indoor uncontrolled environment instead of item 3.4.1-9. The staff evaluated the applicant's claim and finds it acceptable because the component group is being managed for the loss of material aging effect by the Bolting Integrity Program, consistent with the GALL Report recommendations.

LRA Table 3.4-1, item 3.4.1-50a addresses underground stainless steel and steel piping, piping components, and piping elements exposed to an underground environment. The GALL Report recommends GALL Report AMP XI.M41 "Buried and Underground Piping and Tanks" to manage loss of material caused by general (steel only), pitting and crevice corrosion for this component group. The applicant stated that this item is not applicable because it has no stainless steel and steel piping, piping components, and piping elements in the steam and power conversion system exposed to an underground environment. The staff noted that LRA drawing, LR-CW-AP-M-22AP01, shows piping located in a tunnel. The staff finds the applicant's statement acceptable because during the audit, the staff confirmed that this tunnel is normally accessible to plant staff, and therefore, the area is not considered an underground environment in accordance with the GALL Report Section IX.D definition of the buried and underground environment.

LRA Table 3.4-1, item 3.4.1-53 addresses copper alloy (less than or equal to 15 percent zinc and less than or equal to 8 percent aluminum) piping, piping components, and piping elements exposed to air with borated water leakage. The applicant stated that this item is not applicable because there are no in-scope components associated with this item and there are no aging effects, aging mechanisms or AMPs for this component group. SRP-LR item 3.4.1-53 recommends that there is no aging effect or aging mechanism and that no AMP is recommended for this component group exposed to this environment; therefore, the staff finds the applicant's determination acceptable.

LRA Table 3.4-1, item 3.4.1-55 addresses glass piping elements exposed to lubricating oil, outdoor air, condensation, raw water, treated water, air with borated water leakage, gas, closed-cycle cooling water, and uncontrolled indoor air. The applicant stated that the item is not applicable because there are no in-scope components associated with this item. SRP-LR item 3.4.1-55 states that there is no aging effect or aging mechanism and that no AMP is recommended for this component group exposed to these environments; therefore, the staff finds the applicant's determination acceptable.

LRA Table 3.4-1, item 3.4.1-60, addresses piping, piping components, and piping elements made from any material exposed to treated water. The GALL Report recommends GALL Report AMP XI.M17, "Flow-Accelerated Corrosion," to manage wall thinning due to erosion for this component group. The applicant stated that this item is not applicable because it has not experienced this aging effect in any ESF systems. The staff notes that item 3.4.1-60 was generated as part of LR-ISG-2012-01, "Wall Thinning Due to Erosion Mechanisms," which applies to management of erosion mechanisms that had been identified but where the underlying design issue had not been corrected. The staff evaluated the applicant's claim and

finds it acceptable because, during its independent review of the applicant's operating experience database, the staff did not identify any issues with wall thinning due to erosion in any steam and power conversion systems at Callaway Unit 1.

3.4.2.1.2 Reduced Thermal Insulation Resistance Due to Moisture Intrusion

LRA Table 3.4-1, item 3.4.1-65, addresses jacketed Foamglas® (glass dust) insulation exposed to atmosphere/weather which will be managed for reduced thermal insulation resistance due to moisture intrusion. For the AMR item that cites generic note E, the LRA credits the Aboveground Metallic Tanks Program to manage the aging effect for jacketed Foamglas® (glass dust) insulation exposed to atmosphere/weather (external) on the condensate storage tank. The GALL Report recommends GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," to ensure that this aging effect is adequately managed. GALL Report AMP XI.M36 recommends using periodic visual inspections of the external surfaces of components to ensure that there is no damage to the jacketing that would permit in-leakage of moisture.

The staff's evaluation of the applicant's Aboveground Metallic Tanks Program is documented in SER Section 3.0.3.2.8. The staff noted that Aboveground Metallic Tanks Program proposes to manage the aging of jacketed Foamglas® (glass dust) insulation through the use of periodic visual examinations conducted each refueling outage interval. In its review of components associated with item 3.4.1-65, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Aboveground Metallic Tanks Program acceptable because the periodic visual inspections are capable of identifying jacket damage that could allow moisture instruction, which is consistent with aging management approach recommended in GALL Report AMP XI.M36.

The staff concludes that for LRA item 3.4.1-65, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation is Recommended

In LRA Section 3.4.2.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the steam and power conversion systems components and provides information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- cracking due to SCC
- loss of material due to pitting and crevice corrosion
- QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluations 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 3.4.2.2. The staff's review of the applicant's further evaluation follows.

3.4.2.2.1 Cumulative Fatigue Damage

LRA Section 3.4.2.2.1, associated with LRA Table 3.4-1, item 3.4.1-1, addresses steel piping, piping components, and piping elements exposed to steam or treated water in the steam and power conversion system and being managed for cumulative fatigue damage. The applicant addressed the further evaluation criteria of the SRP-LR by stating that fatigue is a TLAA, as defined in 10 CFR 54.3, and is required to be evaluated in accordance with 10 CFR 54.21(c). The applicant stated that the TLAA identified for the steam and power conversion systems is addressed separately in LRA Section 4.3.

The staff reviewed LRA Section 3.4.2.2.1 against the criteria in SRP-LR Section 3.4.2.2.1 which states that fatigue of steam and power conversion system components is a TLAA as defined in 10 CFR 54.3, and that these TLAAs are to be evaluated in accordance with the TLAA acceptance criteria requirements in 10 CFR 54.21(c)(1). The staff reviewed the applicant's AMR items and determined that the AMR results are consistent with the recommendations of the GALL Report and SRP-LR for managing cumulative fatigue damage in steel piping, piping components, and piping elements exposed to steam or treated water, except as identified below.

In its review of the applicant's metal fatigue AMR assessment (item 3.4.1-1) in the steam and power conversion systems, the staff also identified that the applicant did not include the applicable AMR items in LRA Table 2s (Tables 3.x.2-y) for the TLAAs associated with fatigue of certain non-Class 1 piping such as those in the main feedwater system. Therefore, by letter dated September 6, 2012, as part of the RAI 4.3-10, the staff requested the applicant to justify this discrepancy. In its response dated October 11, 2012, the applicant revised LRA Section 3.4 to include an additional AMR item for those SSCs subject to an AMR in accordance with 10 CFR 54.21(a)(1), that was not identified previously. The details of RAI 4.3-10 and the staff's evaluation of the applicant's response are documented in SER Section 4.3.5.2.

Based on its review, the staff concludes that the applicant has met the SRP-LR Section 3.4.2.2.1 criteria. For those items associated with LRA Section 3.4.2.2.1, the staff determined that the LRA is consistent with the GALL Report and that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). SER Section 4.3 documents the staff's review of the applicant's evaluation of the TLAA for these components.

3.4.2.2.2. Cracking due to Stress Corrosion Cracking

LRA Section 3.4.2.2.2, associated with LRA Table 3.4-1, item 3.4.1-2, addresses stainless steel piping, piping components, piping elements, insulation fasteners, and tanks exposed to outdoor air, which will be managed for cracking due to SCC by the External Surfaces Monitoring of Mechanical Components and Aboveground Metallic Tanks Programs. The criteria in SRP-LR Section 3.4.2.2.2 states that cracking due to SCC could occur for stainless steel piping, piping components, piping elements and tanks exposed to outdoor air. The SRP-LR also states that GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," is an acceptable method to manage this aging effect. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the External Surfaces Monitoring of Mechanical Components Program manages cracking due to SCC for stainless steel external surfaces exposed to an outdoor air environment. The staff noted that the LRA also originally associated item 3.4.1-2 with the condensate storage tank, for which loss of material and cracking were being managed with the Aboveground Metallic Tanks Program. However, in a letter dated

December 20, 2013, the applicant revised the condensate storage tank AMR item to cite item 3.4.1-30, consistent with the guidance in the GALL Report, as revised by LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation."

The staff's evaluation of the applicant's External Surfaces Monitoring of Mechanical Components Program is documented in SER Section 3.0.3.1.10. In its review of components associated with item 3.4.1-2 for which the applicant credited the External Surfaces Monitoring of Mechanical Components Program to manage aging, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal is acceptable because: (a) the program includes periodic visual inspections that will occur at least every RFO, which are capable of detecting SCC; and (b) the inspection technique and frequency are consistent with the GALL Report.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.4.2.2.2 criteria. For those items associated with LRA Section 3.4.2.2.2, 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 function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.3 Loss of Material due to Pitting and Crevice Corrosion

LRA Section 3.4.2.2.3, associated with LRA Table 3.4-1, item 3.4.1-3, addresses stainless steel piping, piping components, piping elements, insulation fasteners, and tanks exposed to air outdoor, which will be managed for loss of material due to pitting and crevice corrosion by the External Surfaces Monitoring of Mechanical Components and Aboveground Metallic Tanks Programs. The criteria in SRP-LR Section 3.4.2.2.3 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 outdoor air. The SRP-LR also states that GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," is an acceptable method to manage this aging effect. The applicant addressed the further evaluation criteria of the SRP-LR by stating that, with the exception of the CST, the External Surfaces Monitoring of Mechanical Components Program manages the loss of material from pitting and crevice corrosion for stainless steel external surfaces exposed to an air outdoor environment. The applicant also stated that the CST external surfaces are managed by the Aboveground Metallic Tanks Program.

The staff's evaluation of the applicant's External Surfaces Monitoring of Mechanical Components Program is documented in SER Section 3.0.3.1.10. In its review of components associated with item 3.4.1-3, for which the applicant credited the External Surfaces Monitoring of Mechanical Components Program to manage aging, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal is acceptable because: (a) the program includes periodic visual inspections that will occur at least every RFO, which are capable of detecting loss of material; and (b) the inspection technique and frequency are consistent with the GALL Report.

The staff's evaluation of the applicant's Aboveground Metallic Tanks Program is documented in SER Section 3.0.3.2.8. The staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the Aboveground Metallic Tanks Program is acceptable because: (a) the program uses external visual inspections of the surface of the tank to manage loss of material, including at least once within the 5-year period prior to the period of

extended operation; (b) 25 one-square-foot sections of insulation will be removed to inspect the external surfaces of the tank; and (c) bottom thickness measurements will be performed. The staff finds that these inspections are capable of detecting loss of material, and the inspection technique and frequency are consistent with the GALL Report.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.4.2.2.3 criteria. For those items associated with LRA Section 3.4.2.2.3, 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 function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA Program.

3.4.2.2.5 Operating Experience

SER Section 3.0.5, "Operating Experience for Aging Management Programs," documents the staff's evaluation of the applicant's consideration of operating experience of aging management programs.

3.4.2.2.6 Loss of Material Due to Recurring Internal Corrosion

LRA Section 3.4.2.2.6, as modified through LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion under Insulation," is associated with LRA Table 3.4-1, item 3.4.1-61, and addresses loss of material due to recurring internal corrosion in metallic piping, piping components, and tanks exposed to raw water or waste water. By letter dated October 7, 2013, the staff issued RAI 3.0.3-1 requesting the applicant to address issues related to recurring internal corrosion. In its response dated December 20, 2013, the applicant stated that this item is not applicable because operating experience associated with the steam and power conversion systems does not meet the threshold for significance or frequency of occurrence of the aging effect to be considered as recurring internal corrosion.

The staff evaluated the applicant's claim and finds it acceptable because the applicant's reviews of past operating experience did not identify instances of recurring internal corrosion in the steam and power conversion systems. The staff notes that its independent search of plant-specific operating experience during the AMP audit did not identify instances that warranted augmenting any AMPs that manage components in steam and power conversion systems to address internal corrosion.

3.4.2.3 AMR Results 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 the AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.4.2-1 through 3.4.2-6, the applicant indicated, via notes F through J, that the combination of component type, material, environment, and AERM does not correspond to an AMR 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 AMR item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the AMR item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB 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 Systems—Summary of Aging Management Evaluation—Main Turbine System—LRA Table 3.4.2-1

The staff reviewed LRA Table 3.4.2-1, which summarizes the results of AMR evaluations for the main turbine system component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the main turbine system component groups are consistent with the GALL Report.

3.4.2.3.2 Steam and Power Conversion Systems—Summary of Aging Management Evaluation—Main Steam Supply System—LRA Table 3.4.2-2

The staff reviewed LRA Table 3.4.2-2, which summarizes the results of AMR evaluations for the main steam supply system component groups.

Calcium Silicate Insulation Exposed to Plant Indoor Air. In LRA Tables 3.4.2-2, 3.4.2-3, and 3.4.2-5, as amended by letter dated December 19, 2012, the applicant stated that for calcium silicate insulation exposed to plant indoor air, there is no aging effect and no AMP is proposed. The AMR items originally cited generic note J, indicating that neither the component nor the material and environment are evaluated in the GALL Report.

The staff noted that, subsequent to the applicant's December 19, 2012, LRA amendment, License Renewal Interim Staff Guidance (LR-ISG) LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," was issued, adding SRP-LR item 3.4.1-64 to manage reduced thermal insulation resistance for calcium silicate insulation exposed to plant air using GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components." In LRA Amendment 28, dated December 20, 2013, the applicant revised this item to manage reduced thermal insulation resistance with the External Surfaces Monitoring of Mechanical Components Program, consistent with LR-ISG-2012-02. Therefore, the staff finds the applicant's proposal to manage aging acceptable.

3.4.2.3.3 Steam and Power Conversion Systems—Summary of Aging Management Evaluation—Main Feedwater System—LRA Table 3.4.2-3

The staff reviewed LRA Table 3.4.2-3, which summarizes the results of AMR evaluations for the main feedwater system component groups.

Calcium Silicate Insulation Exposed to Plant Indoor Air. The staff's evaluation for calcium silicate insulation exposed to plant indoor air, for which the applicant cited no aging effect and no proposed AMP, but subsequently revised to be consistent with the GALL Report, is documented in SER Section 3.4.2.3.2.

3.4.2.3.4 Steam and Power Conversion Systems—Summary of Aging Management Evaluation—Steam Generator Blowdown System—LRA Table 3.4.2-1

The staff reviewed LRA Table 3.4.2-1, which summarizes the results of AMR evaluations for the steam generator blowdown system component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the steam generator blowdown system component groups are consistent with the GALL Report.

3.4.2.3.5 Steam and Power Conversion Systems—Summary of Aging Management Evaluation—Auxiliary Feedwater System—LRA Table 3.4.2-5

The staff reviewed LRA Table 3.4.2-5, which summarizes the results of AMR evaluations for the auxiliary feedwater system component groups.

Calcium Silicate Insulation Exposed to Plant Indoor Air. The staff's evaluation for calcium silicate insulation exposed to plant indoor air, for which the applicant cited no aging effect and no proposed AMP, but subsequently revised to be consistent with the GALL Report, is documented in SER Section 3.4.2.3.2.

Elastomeric Flexible Hoses Exposed to Condensation (Internal). In LRA Table 3.4.2-5, as amended by letter dated September 6, 2012, the applicant stated that elastomeric flexible hoses exposed to condensation (internal) 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 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 loss of material due to wear is not an applicable aging effect for elastomeric flexible hoses exposed to condensation (internal) since the presence of contaminants or hard abrasive particles is extremely unlikely as stated in the applicant response to RAI 3.3.2.28-1. The staff's evaluation of the applicant's response to RAI 3.3.2.28-1 is documented in SER Sections 3.3.2.1.7 and 3.3.2.1.10. Furthermore, the staff noted that the applicant manages other aging effects of the elastomeric flexible hoses in other AMR items in LRA Table 3.4 2-5. Based on its review of GALL Report Sections IX.E, "Selected Use of Terms for Describing and Standardizing Aging Effects," and IX.F. "Significant Aging Mechanisms," which indicate that loss of material and hardening and loss of strength are the only applicable aging effects for elastomeric components, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

Elastomeric Flexible Hoses Exposed to Condensation. In LRA Table 3.4.2-5, the applicant stated that the internal surfaces of elastomeric flexible hoses exposed to condensation 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 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 the applicant's identified aging effects and its aging management approach is consistent with GALL Report guidance for elastomers exposed to wet environments. GALL Report item VII.C2.AP-259 recommends that elastomeric components exposed to closed-cycle cooling water be managed for hardening and loss of strength with GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components." The staff also noted that another potential aging effect, loss of material due to wear, would not be expected to be applicable to the internal surfaces of the subject hoses. The internal surfaces of these components are not expected to experience relative motion contact that could lead to wear, nor would condensation include continuous flow of hard abrasive particles. Based on its review of GALL Report Sections IX.E, "Selected Use of Terms for Describing and Standardizing Aging Effects," and IX.F, "Significant Aging Mechanisms," which identify hardening, loss of strength, and loss of material as the only applicable aging effects for elastomeric components, 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 3.0.3.2.12. 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 this program includes opportunistic visual and physical manipulation inspections of elastomeric materials that are capable of detecting hardening and loss of strength.

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

3.4.2.3.6 Steam and Power Conversion Systems—Summary of Aging Management Evaluation—Condensate Storage and Transfer System—LRA Table 3.4.2-6

The staff reviewed LRA Table 3.4.2-6, which summarizes the results of AMR evaluations for the condensate storage and transfer system component groups.

Acrylic or Urethane Insulation Exposed to Atmosphere or Weather (External). In LRA Table 3.4.2-6, the applicant stated that acrylic/urethane insulation exposed to atmosphere/weather will be managed for cracking, blistering, and change in color by the Aboveground Metallic Tanks Program. The AMR item cites generic note J. The AMR item cites plant-specific note 3, which states the following:

> Acrylic/Urethane in an Atmosphere/Weather (Ext.) environment is subjected to UV radiation, moisture, and thermal exposure. The acrylic rubber sealant coating provides UV radiation protection for the urethane foam tank insulation. The dome of the stainless steel tank is prepped with a low halogen (less than 200 ppm) primer prior to the application of the foam urethane. The Aboveground Metallic Tanks Program (B2.1.15) manages cracking blistering or changes in color of the acrylic/urethane insulation. The acrylic rubber sealant is inspected for aging and damage as an indicator for the urethane foam underneath it.

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 the audit, the staff walked down the tank on

which the insulation is used. The acrylic or urethane insulation is located on the dome of the tank. The sides of the tank are insulated with foamglas insulation which, as discussed below, has no AERM and no recommended AMP if jacketed. The insulation on the sides of the tank is jacketed. Based on a review of several manufacturing supplier websites, which offer urethane insulation as a foam that can be sprayed, injected, or in sheets of cured material (i.e., rigid boards), cracking, and blistering and change in color are the only applicable aging effects. Therefore, 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 Aboveground Metallic Tanks Program is documented in SER Section 3.0.3.2.8. The staff finds the applicant's proposal to manage aging using the Aboveground Metallic Tanks Program acceptable because the periodic visual inspections conducted are capable of detecting cracking, blistering, and change in color.

Foamglas Insulation (Glass Dust) Exposed to Atmosphere or Weather (External). In LRA Table 3.4.2-6, the applicant stated that for foamglas insulation (glass dust) exposed to external atmosphere/weather, there is no aging effect and no AMP is proposed. The AMR item cites generic note J. The AMR item also cites plant specific note 2 which states, "[t]he mechanical properties FOAMGLAS (glass dust) are consistent with other glass materials and is evaluated consistent with other glass-like materials in an atmosphere/weather environment in NUREG-1801." The staff reviewed the manufacturer's website and discussed the characteristics of this material with the equipment manufacturer, Pittsburgh Corning Corporation (www.foamglas.com). Based on input from the manufacturer, if this insulation is protected by jacketing material, there are no aging effects. If the material is not jacketed, rain water or heavy dew layers can cause crazing of the surface of the material. During the audit, the staff confirmed that the applicant's insulation procedures require installation of metallic jacketing over all insulation and the procedures provide appropriate requirements for positioning and overlap of the jacketing so as to exclude water entry. The staff finds the applicant's proposal acceptable because: (a) GALL Report items EP-87, AP-167, and SP-108 state that glass exposed to outdoor air has no AERM or recommended AMP, (b) the insulation is composed of glass, and (c) the insulation is covered by metal jacketing, and therefore, moisture would not be expected to allow moisture to reach the surface of the insulation.

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

3.4.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the steam and power conversion systems components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5 Aging Management of Containments, Structures, and Component Supports

This section of the SER documents the staff's review of the applicant's AMR results for the containments, structures, and component supports groups of the following SCs:

- reactor building
- control building
- auxiliary building
- turbine building
- diesel generator building
- miscellaneous in-scope structures
- in-scope tank foundations and structures
- electrical foundations and structures
- radwaste building
- fuel building
- ESW structures
- 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 Programs in Chapters II and III of NUREG-1801 for Containments, Structures, and Component Supports," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the structures and component supports groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.5.2 Staff Evaluation

The staff reviewed LRA Section 3.5 to determine if the applicant provided sufficient information to demonstrate that the effects of aging for the structures and component supports within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will 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 of AMPs to ensure the applicant's claim that certain AMPs were consistent with the GALL Report. The purpose of this audit was to examine the applicant's AMPs and related documentation and to confirm the applicant's claim of consistency with the corresponding GALL Report AMPs. The staff did not repeat its review of the matters described in the GALL Report. The staff's evaluations of the AMPs are documented in SER Section 3.0.3.

The staff reviewed the AMRs to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did confirm that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. Details of the staff's evaluation are discussed in SER Sections 3.5.2.1.

During its review, the staff also selected AMRs consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the SRP-LR Section 3.4.2.2 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 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 3.5-1 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 Containment, Structures, and Component Supports Components in the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
PWR Concrete (Reinforced and Prestressed) and Steel Containments					
Concrete: dome; wall; basemat; ring girders; buttresses, concrete elements, all (3.5.1-1)	Cracking and distortion caused by increased stress levels from settlement	Chapter XI.S2, "ASME Section XI, Subsection IWL" or Chapter XI.S6, "Structure Monitoring" If a de-watering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes, if a de-watering system is relied upon to control settlement	ASME Section XI, Subsection IWL or Structures Monitoring	Consistent with the GALL Report (see SER Section 3.5.2.2.1.1)
Concrete: foundation; subfoundation (3.5.1-2)	Reduction of foundation strength and cracking caused by differential settlement and erosion of porous concrete subfoundation	Chapter XI.S6, "Structures Monitoring" If a de-watering system is relied upon for control of erosion, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes, if a de-watering system is relied upon to control settlement	Not applicable	Not applicable to Callaway (see SER Section 3.5.2.2.1.1)
Concrete: dome; wall; basemat; ring girders; buttresses; Concrete: containment; wall; basemat; Concrete: basemat, concrete fill-in annulus (3.5.1-3)	Reduction of strength and modulus caused by elevated temperature (>150 °F general; >200 °F local)	A plant-specific aging management program is to be evaluated.	Yes, if temperature limits are exceeded	Not applicable	Not applicable to Callaway (see SER Section 3.5.2.2.1.2)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel elements (inaccessible areas): drywell shell; drywell head; and drywell shell (3.5.1-4)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.S1, "ASME Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	Yes, if corrosion is indicated from the IWE examinations	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.2.1.3(1))
Steel elements (inaccessible areas): liner; liner anchors; integral attachments; Steel elements (inaccessible areas): suppression chamber; drywell; drywell head; embedded shell; region shielded by diaphragm floor (as applicable) (3.5.1-5)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.S1, "ASME Section XI, Subsection IWE" and Chapter XI.S4, "10 CFR Part 50, Appendix J"	Yes, if corrosion is indicated from the IWE examinations	ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J	Consistent with GALL Report (see SER Section 3.5.2.2.1.3(1))
Steel elements: torus shell (3.5.1-6)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.S1, "ASME Section XI, Subsection IWE" and Chapter XI.S4, "10 CFR Part 50, Appendix J"	Yes, if corrosion is significant; recoating of the torus is recommended	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.2.1.3 (2))
Steel elements: torus ring girders; downcomers; Steel elements: suppression chamber shell (interior surface) (3.5.1-7)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.S1, "ASME Section XI, Subsection IWE"	Yes, if corrosion is significant	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.2.1.3(3))
Pre-stressing system: tendons (3.5.1-8)	Loss of prestress caused by relaxation; shrinkage; creep; elevated temperature	Yes, TLAA	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.5.2.2.1.4)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Penetration sleeves; penetration bellows Steel elements: torus; vent line; vent header; vent line bellows; downcomers, Suppression pool shell; unbraced downcomers, Steel elements: vent header; downcomers (3.5.1-9)	Cumulative fatigue damage caused by fatigue (Only if CLB fatigue analysis exists)	Yes, TLAA	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.5.2.2.1.5)
Penetration sleeves; penetration bellows (3.5.1-10)	Cracking caused by stress corrosion cracking	Chapter XI.S1, “ASME Section XI, Subsection IWE,” and Chapter XI.S4, “10 CFR Part 50, Appendix J”	No	ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J	Consistent with the GALL Report (see SER Section 3.5.2.2.1.6)
Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, Concrete (inaccessible areas): basemat, Concrete (inaccessible areas): dome; wall; basemat (3.5.1-11)	Loss of material (spalling, scaling) and cracking caused by freeze-thaw	Further evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index >100 day-inch/yr) (NUREG-1557).	Yes	Not applicable	Not applicable to Callaway (see SER Section 3.5.2.2.1.7)
Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, concrete (inaccessible areas): basemat, concrete (inaccessible areas): containment; wall; basemat, concrete (inaccessible areas): basemat, concrete fill-in annulus (3.5.1-12)	Cracking caused by expansion from reaction with aggregates	Further evaluation is required to determine if a plant-specific aging management program is needed.	Yes	Not applicable	Not applicable to Callaway (see SER Section 3.5.2.2.1.8)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Concrete (inaccessible areas): basemat, concrete (inaccessible areas): dome; wall; basemat (3.5.1-13)	Increase in porosity and permeability; loss of strength caused by leaching of calcium hydroxide and carbonation	Further evaluation is required to determine if a plant-specific aging management program is needed.	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.2.1.9)
Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, concrete (inaccessible areas): containment; wall; basemat (3.5.1-14)	Increase in porosity and permeability; loss of strength caused by leaching of calcium hydroxide and carbonation	Further evaluation is required to determine if a plant-specific aging management program is needed.	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.2.1.9)
Concrete (accessible areas): basemat (3.5.1-15)	Increase in porosity and permeability; loss of strength caused by leaching of calcium hydroxide and carbonation	Chapter XI.S2, “ASME Section XI, Subsection IWL”	No	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.1.1)
Concrete (accessible areas): basemat, concrete: containment; wall; basemat (3.5.1-16)	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) caused by aggressive chemical attack	Chapter XI.S2, “ASME Section XI, Subsection IWL,” or Chapter XI.S6, “Structures Monitoring”	No	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.1.1)
Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses (3.5.1-17)	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) caused by aggressive chemical attack	Chapter XI.S2, “ASME Section XI, Subsection IWL”	No	ASME Section XI, Subsection IWL	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses, concrete (accessible areas): basemat (3.5.1-18)	Loss of material (spalling, scaling) and cracking caused by freeze-thaw	Chapter XI.S2, "ASME Section XI, Subsection IWL"	No	ASME Section XI, Subsection IWL	Consistent with the GALL Report
Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses, concrete (accessible areas): basemat, Concrete (accessible areas): containment; wall; basemat, concrete (accessible areas): basemat, concrete fill-in annulus (3.5.1-19)	Cracking caused by expansion from reaction with aggregates	Chapter XI.S2, "ASME Section XI, Subsection IWL"	No	ASME Section XI, Subsection IWL	Consistent with the GALL Report
Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses, concrete (accessible areas): containment; wall; basemat (3.5.1-20)	Increase in porosity and permeability; loss of strength caused by leaching of calcium hydroxide and carbonation	Chapter XI.S2, "ASME Section XI, Subsection IWL"	No	ASME Section XI, Subsection IWL	Consistent with the GALL Report
Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses; reinforcing steel, concrete (accessible areas): basemat; reinforcing steel, concrete (accessible areas): dome; wall; basemat; reinforcing steel (3.5.1-21)	Cracking; loss of bond; and loss of material (spalling, scaling) caused by corrosion of embedded steel	Chapter XI.S2, "ASME Section XI, Subsection IWL"	No	ASME Section XI, Subsection IWL	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Concrete (inaccessible areas): basemat; reinforcing steel (3.5.1-22)	Cracking; loss of bond; and loss of material (spalling, scaling) caused by corrosion of embedded steel	Chapter XI.S6, "Structures Monitoring"	No	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.1.1)
Concrete (inaccessible areas): basemat; reinforcing steel, Concrete (inaccessible areas): dome; wall; basemat; reinforcing steel (3.5.1-23)	Cracking; loss of bond; and loss of material (spalling, scaling) caused by corrosion of embedded steel	Chapter XI.S2, "ASME Section XI, Subsection IWL," or Chapter XI.S6, "Structures Monitoring"	No	Not applicable	Not applicable Callaway (see SER Section 3.5.2.1.1)
Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, Concrete (inaccessible areas): basemat, Concrete (accessible areas): dome; wall; basemat (3.5.1-24)	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) caused by aggressive chemical attack	Chapter XI.S2, "ASME Section XI, Subsection IWL," or Chapter XI.S6, "Structures Monitoring"	No	ASME Section XI, Subsection IWL or Structures Monitoring	Consistent with the GALL Report
Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses; reinforcing steel (3.5.1-25)	Cracking; loss of bond; and loss of material (spalling, scaling) caused by corrosion of embedded steel	Chapter XI.S2, "ASME Section XI, Subsection IWL," or Chapter XI.S6, "Structures Monitoring"	No	Not applicable	Consistent with the GALL Report (see SER Section 3.5.2.1.1)
Moisture barriers (caulking, flashing, and other sealants) (3.5.1-26)	Loss of sealing caused by wear, damage, erosion, tear, surface cracks, or other defects	Chapter XI.S1, "ASME Section XI, Subsection IWE"	No	ASME Section XI, Subsection IWE or Structures Monitoring	Not applicable to Callaway (see SER Section 3.0.3.2.17)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Penetration sleeves; penetration bellows, steel elements: torus; vent line; vent header; vent line bellows; downcomers, suppression pool shell (3.5.1-27)	Cracking caused by cyclic loading (CLB fatigue analysis does not exist)	Chapter XI.S1, "ASME Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	Not applicable	Not applicable to Callaway (see SER Section 3.5.2.1.1)
Personnel airlock, equipment hatch, CRD hatch (3.5.1-28)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.S1, "ASME Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J	Consistent with the GALL Report
Personnel airlock, equipment hatch, CRD hatch: locks, hinges, and closure mechanisms (3.5.1-29)	Loss of leak tightness caused by mechanical wear of locks, hinges and closure mechanisms	Chapter XI.S1, "ASME Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J	Consistent with the GALL Report
Pressure-retaining bolting (3.5.1-30)	Loss of preload caused by self-loosening	Chapter XI.S1, "ASME Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J	Consistent with the GALL Report
Pressure-retaining bolting, steel elements: downcomer pipes (3.5.1-31)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.S1, "ASME Section XI, Subsection IWE"	No	ASME Section XI, Subsection IWE	Consistent with the GALL Report
Prestressing system: tendons; anchorage components (3.5.1-32)	Loss of material caused by corrosion	Chapter XI.S2, "ASME Section XI, Subsection IWL"	No	ASME Section XI, Subsection IWL	Consistent with the GALL Report
Seals and gaskets (3.5.1-33)	Loss of sealing caused by wear, damage, erosion, tear, surface cracks, or other defects	Chapter XI.S4, "10 CFR Part 50, Appendix J "	No	10 CFR Part 50, Appendix J	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Service Level I coatings (3.5.1-34)	Loss of coating integrity caused by blistering, cracking, flaking, peeling, or physical damage	Chapter XI.S8, "Protective Coating Monitoring and Maintenance"	No	Protective Coating Monitoring and Maintenance	Consistent with the GALL Report
Steel elements (accessible areas): liner; liner anchors; integral attachments, penetration sleeves, steel elements (accessible areas): drywell shell; drywell head; drywell shell in sand pocket regions;, steel elements (accessible areas): suppression chamber; drywell; drywell head; embedded shell; region shielded by diaphragm floor (as applicable), steel elements (accessible areas): drywell shell; drywell head (3.5.1-35)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.S1, "ASME Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J	Consistent with the GALL Report
Steel elements: drywell head; downcomers (3.5.1-36)	Fretting or lockup caused by mechanical wear	Chapter XI.S1, "ASME Section XI, Subsection IWE"	No	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.1.1)
Steel elements: suppression chamber (torus) liner (interior surface) (3.5.1-37)	Loss of material caused by general (steel only), pitting, and crevice corrosion	Chapter XI.S1, "ASME Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.1.1)
Steel elements: suppression chamber shell (interior surface) (3.5.1-38)	Cracking caused by stress corrosion cracking	Chapter XI.S1, "ASME Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel elements: vent line bellows (3.5.1-39)	Cracking caused by stress corrosion cracking	Chapter XI.S1, "ASME Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.1.1)
Unbraced downcomers, Steel elements: vent header; downcomers (3.5.1-40)	Cracking caused by cyclic loading (CLB fatigue analysis does not exist)	Chapter XI.S1, "ASME Section XI, Subsection IWE"	No	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.1.1)
Steel elements: drywell support skirt, steel elements (inaccessible areas): support skirt (3.5.1-41)	None	None	NA - No AEM or AMP	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.1.1)
Safety-Related and Other Structures; and Component Supports					
Groups 1-3, 5, 7-9:concrete (inaccessible areas): foundation (3.5.1-42)	Loss of material (spalling, scaling) and cracking caused by freeze-thaw	Further evaluation is required for plants that are located in moderate to severe weathering conditions (weathering index >100 day-inch/yr) (NUREG-1557)	Yes	Not applicable	Not applicable to Callaway (see SER Section 3.5.2.2.2.1(1))
All groups except Group 6:concrete (inaccessible areas): all (3.5.1-43)	Cracking caused by expansion from reaction with aggregates	Further evaluation is required to determine if a plant-specific aging management program is needed.	Yes	Not applicable	Not applicable to Callaway (see SER Section 3.5.2.2.2.1(2))
All Groups: concrete: all (3.5.1-44)	Cracking and distortion caused by increased stress levels from settlement	Chapter XI.S6, "Structures Monitoring," if a de-watering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes	Structures Monitoring or ASME Section XI, Subsection IWL	Consistent with the GALL Report (see SER Section 3.5.2.2.2.1(3))

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Groups 1-3, 5-9: concrete: foundation; subfoundation (3.5.1-45)	Reduction in foundation strength, cracking caused by differential settlement, erosion of porous concrete subfoundation	Chapter XI.S6, "Structures Monitoring," if a de-watering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.1.1)
Groups 1-3, 5-9: concrete: foundation; subfoundation (3.5.1-46)	Reduction of foundation strength and cracking caused by differential settlement and erosion of porous concrete subfoundation	Chapter XI.S6, "Structures Monitoring," if a de-watering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes	Not applicable	Not applicable to Callaway (see SER Section 3.5.2.2.2.1(3))
Groups 1-5, 7-9: concrete (inaccessible areas): exterior above- and below-grade; foundation (3.5.1-47)	Increase in porosity and permeability; loss of strength caused by leaching of calcium hydroxide and carbonation	Further evaluation is required to determine if a plant-specific aging management program is needed.	Yes,	Not applicable	Not applicable to Callaway (see SER Section 3.5.2.2.2.1(4))
Groups 1-5: concrete: all (3.5.1-48)	Reduction of strength and modulus caused by elevated temperature (>150 °F general; >200 °F local)	A plant-specific aging management program is to be evaluated.	Yes	Not applicable	Not applicable to Callaway (see SER Section 3.5.2.2.2.2)
Groups 6 - concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab (3.5.1-49)	Loss of material (spalling, scaling) and cracking caused by freeze-thaw	Further evaluation is required for plants that are located in moderate to severe weathering conditions (weathering index >100 day-inch/yr) (NUREG-1557)	Yes	Not applicable	Not applicable to Callaway (see SER Section 3.5.2.2.2.3(1))

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Groups 6: concrete (inaccessible areas): all (3.5.1-50)	Cracking caused by expansion from reaction with aggregates	Further evaluation is required to determine if a plant-specific aging management program is needed.	Yes	Not applicable	Not applicable to Callaway (see SER Section 3.5.2.2.2.3(2))
Groups 6: concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab (3.5.1-51)	Increase in porosity and permeability; loss of strength caused by leaching of calcium hydroxide and carbonation	Further evaluation is required to determine if a plant-specific aging management program is needed.	Yes	Not applicable	Not applicable to Callaway (see SER Section 3.5.2.2.2.3(3))
Groups 7, 8 - steel components: tank liner (3.5.1-52)	Cracking caused by stress corrosion cracking; Loss of material caused by pitting and crevice corrosion	A plant-specific aging management program is to be evaluated.	Yes	Not applicable	Not applicable to Callaway (see SER Section 3.5.2.2.2.4)
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-53)	Cumulative fatigue damage caused by fatigue (Only if CLB fatigue analysis exists)	Yes, TLAA	Yes,	TLAA	Consistent with GALL Report (see SER Section 3.5.2.2.2.5)
All groups except 6: concrete (accessible areas): all (3.5.1-54)	Cracking caused by expansion from reaction with aggregates	Chapter XI.S6, “Structures Monitoring”	No	Structures Monitoring	Consistent with the GALL Report
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates (3.5.1-55)	Reduction in concrete anchor capacity caused by local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Chapter XI.S6, “Structures Monitoring”	No	Structures Monitoring	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Concrete: exterior above- and below-grade; foundation; interior slab (3.5.1-56)	Loss of material caused by abrasion; cavitation	Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	Consistent with the GALL Report
Constant and variable load spring hangers; guides; stops (3.5.1-57)	Loss of mechanical function caused by corrosion, distortion, dirt, overload, fatigue caused by vibratory and cyclic thermal loads	Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	ASME Section XI, Subsection IWF	Consistent with the GALL Report
Earthen water-control structures: dams; embankments; reservoirs; channels; canals and ponds (3.5.1-58)	Loss of material; loss of form caused by erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	Consistent with the GALL Report
Group 6: concrete (accessible areas): all (3.5.1-59)	Cracking; loss of bond; and loss of material (spalling, scaling) caused by corrosion of embedded steel	Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Group 6: concrete (accessible areas): exterior above- and below-grade; foundation (3.5.1-60)	Loss of material (spalling, scaling) and cracking caused by freeze-thaw	Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	Consistent with the GALL Report
Group 6: concrete (accessible areas): exterior above- and below-grade; foundation; interior slab (3.5.1-61)	Increase in porosity and permeability; loss of strength caused by leaching of calcium hydroxide and carbonation	Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	Consistent with the GALL Report
Group 6: wooden piles; sheeting (3.5.1-62)	Loss of material; change in material properties caused by weathering, chemical degradation, and insect infestation repeated wetting and drying, fungal decay	Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Not applicable	Not applicable to Callaway (see SER Section 3.5.2.1.1)
Groups 1-3, 5, 7-9: concrete (accessible areas): exterior above- and below-grade; foundation (3.5.1-63)	Increase in porosity and permeability; loss of strength caused by leaching of calcium hydroxide and carbonation	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Groups 1-3, 5, 7-9: concrete (accessible areas): exterior above- and below-grade; foundation (3.5.1-64)	Loss of material (spalling, scaling) and cracking caused by freeze-thaw	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring	Consistent with the GALL Report
Groups 1-3, 5, 7-9: concrete (inaccessible areas): below-grade exterior; foundation, Groups 1-3, 5, 7-9: concrete (accessible areas): below-grade exterior; foundation, Groups 6: concrete (inaccessible areas): all (3.5.1-65)	Cracking; loss of bond; and loss of material (spalling, scaling) caused by corrosion of embedded steel	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring	Consistent with the GALL Report
Groups 1-5, 7, 9: concrete (accessible areas): interior and above-grade exterior (3.5.1-66)	Cracking; loss of bond; and loss of material (spalling, scaling) caused by corrosion of embedded steel	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring	Consistent with the GALL Report
Groups 1-5, 7, 9: concrete: interior; above-grade exterior, groups 1-3, 5, 7-9 - concrete (inaccessible areas): below-grade exterior; foundation, group 6: concrete (inaccessible areas): all (3.5.1-67)	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) caused by aggressive chemical attack	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring	Consistent with the GALL Report
High-strength structural bolting (3.5.1-68)	Cracking caused by stress corrosion cracking	Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	ASME Section XI, Subsection IWF	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
High-strength structural bolting (3.5.1-69)	Cracking caused by stress corrosion cracking	Chapter XI.S6, "Structures Monitoring" Note: ASTM A 325, F 1852, and ASTM A 490 bolts used in civil structures have not shown to be prone to SCC. SCC potential need not be evaluated for these bolts.	No	Structures Monitoring	Not applicable to Callaway (see SER Section 3.5.2.1.1)
Masonry walls: all (3.5.1-70)	Cracking caused by restraint shrinkage, creep, and aggressive environment	Chapter XI.S5, "Masonry Walls"	No	Masonry Walls and Fire Protection	Consistent with the GALL Report (see SER Section 3.5.2.1.2)
Masonry walls: all (3.5.1-71)	Loss of material (spalling, scaling) and cracking caused by freeze-thaw	Chapter XI.S5, "Masonry Walls"	No	Not applicable	Not applicable to Callaway (see SER Section 3.5.2.1.1)
Seals; gasket; moisture barriers (caulking, flashing, and other sealants) (3.5.1-72)	Loss of sealing caused by deterioration of seals, gaskets, and moisture barriers (caulking, flashing, and other sealants)	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring	Consistent with the GALL Report
Service Level I coatings (3.5.1-73)	Loss of coating integrity caused by blistering, cracking, flaking, peeling, physical damage	Chapter XI.S8, "Protective Coating Monitoring and Maintenance"	No	Protective Coating Monitoring and Maintenance	Consistent with the GALL Report
Sliding support bearings; sliding support surfaces (3.5.1-74)	Loss of mechanical function caused by corrosion, distortion, dirt, debris, overload, wear	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Sliding surfaces (3.5.1-75)	Loss of mechanical function caused by corrosion, distortion, dirt, debris, overload, wear	Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	ASME Section XI, Subsection IWF	Consistent with the GALL Report
Sliding surfaces: radial beam seats in BWR drywell (3.5.1-76)	Loss of mechanical function caused by corrosion, distortion, dirt, overload, wear	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring	Not applicable to PWRs (see SER Section 3.5.2.1.1)
Steel components: all structural steel (3.5.1-77)	Loss of material caused by corrosion	Chapter XI.S6, "Structures Monitoring" 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.	No	Structures Monitoring	Consistent with the GALL Report
Steel components: fuel pool liner (3.5.1-78)	Cracking caused by stress corrosion cracking; Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Monitoring of the spent fuel pool water level in accordance with technical specifications and leakage from the leak chase channels.	No, unless leakages have been detected through the SFP liner that cannot be accounted for from the leak chase channels	Water Chemistry	Consistent with the GALL Report
Steel components: piles (3.5.1-79)	Loss of material caused by corrosion	Chapter XI.S6, "Structures Monitoring"	No	Not applicable	Not applicable to Callaway (see SER Section 3.5.2.1.1)
Structural bolting (3.5.1-80)	Loss of material caused by general, pitting and crevice corrosion	Chapter XI.S6, "Structures Monitoring"	No	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Consistent with the GALL Report (see SER Section 3.5.2.1.3)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Structural bolting (3.5.1-81)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	ASME Section XI, Subsection IWF	Consistent with the GALL Report
Structural bolting (3.5.1-82)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring	Consistent with the GALL Report
Structural bolting (3.5.1-83)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants and Structures Monitoring	Consistent with GALL Report (see SER Section 3.5.2.1.4)
Structural bolting (3.5.1-84)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	Not applicable	Not applicable to PWRs (see SER Section 3.5.2.1.1)
Structural bolting (3.5.1-85)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," for BWR water, and Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	Not applicable	Not applicable to Callaway (see SER Section 3.5.2.1.1)
Structural bolting (3.5.1-86)	Loss of material caused by pitting and crevice corrosion	Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	ASME Section XI, Subsection IWF	Consistent with the GALL Report
Structural bolting (3.5.1-87)	Loss of preload caused by self-loosening	Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	ASME Section XI, Subsection IWF	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Structural bolting (3.5.1-88)	Loss of preload caused by self-loosening	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring and Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Consistent with GALL Report (see SER Section 3.5.2.1.5)
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-89)	Loss of material caused by boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion"	No	Boric Acid Corrosion	Consistent with the GALL Report
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-90)	Loss of material caused by general (steel only), pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for BWR water, and Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	Not applicable	Not applicable to Callaway (see SER Section 3.5.2.1.1)
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-91)	Loss of material caused by general and pitting corrosion	Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	ASME Section XI, Subsection IWF	Consistent with the GALL Report
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-92)	Loss of material caused by general and pitting corrosion	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring	Consistent with the GALL Report
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-93)	Loss of material caused by pitting and crevice corrosion	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring and ASME Section XI, Subsection IWF	Consistent with GALL Report (see SER Section 3.5.2.1.6)
Vibration isolation elements (3.5.1-94)	Reduction or loss of isolation function caused by radiation hardening, temperature, humidity, sustained vibratory loading	Chapter XI.S3, "ASME Section XI, Subsection IWF"	No	Not applicable	Not applicable to Callaway (see SER Section 3.5.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Aluminum, galvanized steel and stainless steel support members; welds; bolted connections; support anchorage to building structure exposed to air – indoor, uncontrolled (3.5.1-95)	None	None	NA - No AEM or AMP	None	Consistent with GALL Report (see SER Section 3.5.2.1.7)

3.5.2.1 AMR Results Consistent with the GALL Report

LRA Section 3.5.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the containments, structures, and structural components and their commodity groups:

- 10 CFR Part 50, Appendix J
- ASME Section XI, Subsection IWE
- ASME Section XI, Subsection IWF
- ASME Section XI, Subsection IWL
- Boric Acid Corrosion
- Fire Protection
- Masonry Walls
- Regulatory Guide (RG) 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants
- Protective Coating Monitoring and Maintenance
- Structures Monitoring
- Water Chemistry

Although not identified directly in LRA Section 3.5.2.1, LRA Table 3.5-1 identifies the TLAA Program 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 3.5.2-12 summarize AMRs for the containments, structures, and component supports component groups and indicate AMRs claimed to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant claimed consistency with theGALL Report and for which it does not recommend further evaluation, the staff's audit and 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 audited those AMRs with notes A–E, indicating how the AMR is consistent with the GALL Report.

Note A indicates that the AMR item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. The staff reviewed these items to confirm consistency with the GALL Report and validity of the AMR for the site-specific conditions.

Note B indicates that the AMR item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff reviewed these items to 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, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report; however, the applicant identified in the GALL Report a different component with the same material, environment, aging effect, and AMP as the component under review. The staff reviewed these items to 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, 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's evaluation follows.

3.5.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.5-1, items 3.5.1-15, 3.5.1-16, 3.5.1-22, 3.5.1-36 through 3.5.1-41, 3.5.1-45, 3.5.1-76, and 3.5.1-84, 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 that these items are not applicable to Callaway, which is a PWR.

For LRA Table 3.5-1, items 3.5.1-23, 3.5.1-27, 3.5.1-62, 3.5.1-71, 3.5.1-79, 3.5.1-85, and 3.5.1-94, the applicant claimed that the corresponding items in the GALL Report are not applicable because the component, material, and environment combination described in the SRP-LR does not exist for in-scope SCs at Callaway. The staff reviewed the LRA and FSAR and confirmed that the applicant's LRA does not have any AMR results applicable for these items.

For LRA Table 3.5-1 items discussed below, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable; however, the staff non-applicability verification of these items required the review of sources beyond the LRA and FSAR, and/or the issuance of RAIs.

LRA Table 3.5-1, item 3.5.1-25 addresses inaccessible concrete exposed to air. The GALL Report recommends GALL Report AMP XI.S2, "ASME Section XI, Subsection IWL," or XI.S6, "Structures Monitoring," to manage cracking, loss of bond, and loss of material caused by corrosion of embedded steel for this component group. The applicant stated that this item is not applicable because there is no inaccessible containment concrete exposed to an air environment. The staff evaluated the applicant's claim and does not agree that all containment concrete exposed to air is accessible for inspection. For example, during a walkdown on May 2, 2012, the staff observed external containment concrete that appeared to be obstructed by the containment vent duct. In addition, it is not clear to the staff how inaccessible containment concrete exposed to other environments will be managed during the period of extended operation. Therefore, by letter dated August 6, 2012, the staff issued RAI 3.5.1.25-1 requesting that the applicant confirm that all containment concrete exposed to air is accessible for inspection, and to explain how containment concrete exposed to other environments will be managed for aging during the period of extended operation.

In its response dated September 6, 2012, the applicant revised Table 3.5-1, item 3.5.1-25, to be consistent with the GALL Report and noted that inspections of inaccessible areas would be conducted in accordance with the guidance in the GALL Report. The applicant further stated that normally inaccessible structural components are examined when scheduled maintenance work and planned plant modifications permit access.

The staff finds the applicant's response acceptable because the response identifies that inaccessible containment concrete does exist and it aligns the aging management of the commodity with the GALL Report recommended aging management approach. As part of its response the applicant also revised item 3.5.1-25 to be consistent with the GALL Report. The staff's concern described in RAI 3.5.1.25-1 is resolved. Additional information on inaccessible containment concrete can be found in the staff's review of the applicant's ASME Section XI, Subsection IWL Program and RAI B2.1.27-3, in SER Section 3.0.3.1.12. In its review of components associated with items 3.5.1-25, the staff finds the applicant's proposal to manage aging using the ASME Section XI, Subsection IWL Program acceptable because it is the GALL Report recommended AMP for this component, environment, and aging effect.

LRA Table 3.5-1, item 3.5.1-69, as amended by letter dated August 9, 2012, addresses high-strength structural bolting exposed to air-indoor, uncontrolled or air-outdoor. The GALL Report recommends GALL Report AMP XI.S6, "Structures Monitoring" to manage cracking caused by SCC for this component group. The applicant stated that this item is not applicable

because Callaway has no in-scope high-strength structural bolting susceptible to cracking caused by SCC. The staff evaluated the applicant's claim and finds it acceptable because in its August 9, 2012, response to RAI B2.1.28-1, the applicant stated that it reviewed drawings, plant specifications, vendor specifications, and procurement documents, and performed key word searches of plant databases and concluded that there are no structural bolts within the scope of license renewal for which augmented volumetric examinations are required. The staff's review of RAI B2.1.28-1 is documented in SER Section 3.0.3.2.16.

LRA Table 3.5.1, item 3.5.1-90 addresses steel and stainless steel Class 1 support members exposed to treated water with a temperature less than 60 °C (140 °F). The GALL Report recommends GALL Report AMP XI.M2, "Water Chemistry," for BWR water, and XI.S3, "ASME Section XI, Subsection IWF," to manage loss of material caused by general, pitting, and crevice corrosion for this component group. The applicant stated that this item is not applicable because it only applies to BWR plants. The staff reviewed the corresponding item in the SRP-LR, and the associated items in the GALL Report, and noted that the items apply to Class 1 supports, regardless of the plant design. Therefore, by letter dated August 6, 2012, the staff issued RAI 3.5.1.90-1 requesting the applicant explain why this item is not applicable, or provide an acceptable AMP to manage loss of material caused by general, pitting, and crevice corrosion of steel and stainless steel support members exposed to treated water with a temperature less than 60 °C (140 °F).

In its response dated September 6, 2012, the applicant stated that item 3.5.1-90 is not applicable because there are no steel or stainless steel ASME Code Class 1 support members submerged in treated water. As part of its response the applicant revised LRA Table 3.5.1, item 3.5.1-90 to state that the item is not applicable because Callaway has no steel or stainless steel ASME Class 1 support members submerged in treated water.

The staff reviewed the applicant's response and finds it acceptable because the applicant clearly stated that the component, material and environment combination discussed in item 3.5.1-90 does not exist at Callaway. Therefore, the not applicable determination is acceptable. The staff's concern described in RAI 3.5.1.90-1 is resolved. The staff reviewed the LRA and FSAR and confirmed that the applicant's LRA does not have any AMR results that are applicable for these items.

3.5.2.1.2 Cracking Due to Restraint Shrinkage, Creep, and Aggressive Environment

LRA Table 3.5-1, item 3.5.1-70 addresses masonry walls exposed to indoor or outdoor air which will be managed for cracking due to restraint shrinkage, creep, and aggressive environment. For the AMR items that cite generic note E, the LRA credits the Masonry Walls and Fire Protection Programs to manage this aging effect for concrete block masonry walls. In a letter dated February 14, 2014, the applicant revised one of the subject AMR items in Table 3.5.2-4 to credit only the Masonry Walls Program because the fire barrier intended function of this component was removed per the applicant's transition to a risk-informed, performance-based fire protection plan that incorporates NFPA-805. The remaining AMR items cite both the Masonry Walls and Fire Protection Programs. The GALL Report recommends GALL Report AMP XI.S5 "Masonry Walls," to ensure that these aging effects are adequately managed. GALL Report AMP XI.S5 recommends using visual inspections with a 5-year frequency to manage aging.

The staff's evaluation of the applicant's Masonry Wall and Fire Protection Programs is documented in SER Sections 3.0.3.1.14 and 3.0.3.2.6, respectively. The staff noted that the

Masonry Wall and Fire Protection Programs both propose to manage the aging of concrete block masonry walls through the use of visual inspections. The staff further noted that the GALL Report recommended program, the Masonry Wall Program, is being credited for all of the masonry walls, and the Fire Protection Program is being credited in addition to the Masonry Wall Program for walls that provide a fire barrier function. In its review of components associated with item 3.5.1-70 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Masonry Wall and Fire Protection Programs acceptable because the recommended GALL Report AMP XI.S5 "Masonry Walls," is being credited, and Fire Protection Program is also being credited in addition to the recommended GALL Report AMP XI.S5.

The staff concludes that for LRA item 3.5.1-70, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.2.1.3 Loss of Material Due to General, Pitting and Crevice Corrosion

LRA Table 3.5-1, item 3.5.1-80 addresses carbon steel structural bolting exposed to plant indoor air which will be managed for loss of material caused by general, pitting, and crevice corrosion. For the AMR items that cite generic note E, the LRA credits the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program to manage the aging effect for carbon steel structural bolting. The GALL Report recommends GALL Report AMP XI.S6, "Structures Monitoring," to ensure that these aging effects are adequately managed. GALL Report AMP XI.S6 recommends visual inspection of structural bolting, at a frequency not to exceed 5 years, to manage aging.

The staff's evaluation of the applicant's Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program is documented in SER Section 3.0.3.2.5. The staff noted that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program proposes to manage the aging of carbon steel structural bolting through the use of visual inspections. In its review of components associated with item 3.5.1-80 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program acceptable because visual inspections for cranes are performed in accordance with ASME Code B30 standards, which require inspections more frequently than the 5-year interval recommended in GALL Report AMP XI.S6.

The staff concludes that for LRA item 3.5.1-80, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.2.1.4 Loss of Material Due to General, Pitting, and Crevice Corrosion

LRA Table 3.5-1, item 3.5.1-83 addresses structural steel exposed to a submerged environment, which will be managed for loss of material due to general, pitting, and crevice corrosion. For the AMR item that cites generic note E, the LRA credits the Structures Monitoring Program to manage the aging effect for carbon steel structural steel. The GALL Report recommends GALL Report AMP XI.S7, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," or the FERC/US Army Corp of Engineers dam inspections and maintenance programs to ensure that these aging effects are adequately

managed. GALL Report AMP XI.S7 recommends using periodic visual inspections at least once every 5 years to manage aging.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.17. The staff notes that the Structures Monitoring Program proposes to manage the aging of carbon structural steel through the use of periodic visual inspections, by personnel qualified in accordance with ACI 349.3R, at a frequency not to exceed 5 years. The staff also notes that although the GALL Report does not provide a line to evaluate carbon structural steel in a submerged environment for components in Group 3 structures, the Structures Monitoring Program would be capable of managing these aging effects. In its review of components associated with item 3.5.1-83 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Structures Monitoring Program acceptable because personnel performing inspections are qualified in accordance with ACI 349.3R, and inspections are performed at a frequency not to exceed 5 years, which is consistent with the recommendations in GALL Report AMP XI.S7 for structural steel exposed to a submerged environment.

During its review of components associated with item 3.5.1-83 for which the applicant cited generic note C, the staff noted that the LRA credits the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program to manage the aging effect for carbon steel ASME Code Class 2 and 3 supports. The staff noted that ASME Code Class 2 and 3 supports should be within the scope of the ASME Section XI, Subsection IWF Program. The scope, frequency, and inspection criteria as specified in GALL Report AMP XI.S3, "ASME Section XI, Subsection IWF," for ASME Code Class 2 and 3 supports is different from that specified in GALL Report AMP XI.S7 for non-ASME steel components monitored for loss of material caused by corrosion. GALL Report AMP XI.S3 recommends that a sample of ASME Code Class 1, 2, and 3 component supports that are not exempt from examination and 100 percent of MC component supports be examined as specified in Table IWF-2500-1. The sample size examined for ASME Code Class 1, 2, and 3 component supports is as specified in Table IWF-2410-2. The detailed acceptance standards for ASME Code Class 1, 2, and 3 component supports are delineated in IWF-3400. GALL Report AMP XI.S7 recommends inspection of structures and components at a frequency of 5 years in accordance with ACI 349.3R. Therefore, by letter dated July 9, 2012, the staff issued RAI 3.5.2.12-1 requesting the applicant to explain why the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, instead of the ASME Section XI, Subsection IWF Program, is being used to monitor ASME Code Class 2 and 3 supports that are submerged in water. The staff also requested the applicant to include a discussion on how the scope, frequency, and acceptance criteria specified in ASME Code Section XI, Subsection IWF can be implemented by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program for ASME Code Class 2 and 3 carbon steel supports that are submerged in water.

In its response dated August 9, 2012, the applicant stated that the ASME Code Class 2 and 3 carbon steel supports submerged in water were included in LRA Table 3.5.2-12 as supports for the ESW discharge pipe located in the UHS cooling tower sump. The applicant further stated that as shown in FSAR-SA Figure 3.8-9, this 36-inch diameter pipe is supported within the concrete wall and does not require an additional support structure inside the sump. Therefore, as part of its response, the applicant revised the LRA to indicate the absence of submerged ASME Code Class 2 and 3 supports.

The staff reviewed the applicant's response and finds it acceptable because the staff confirmed in its review of FSAR-SA Figure 3.8-9, that there are no ASME Code Class 2 and 3 carbon steel

supports for the ESW discharge pipe located in the UHS cooling tower sump. The staff's concern described in RAI 3.5.2.12-1 is resolved.

The staff concludes that for LRA item 3.5.1-83, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.2.1.5 Loss of Preload due to Self-Loosening

LRA Table 3.5-1, item 3.5.1-88 addresses carbon steel structural bolting exposed to plant indoor air or borated water leakage which will be managed for loss of preload due to self-loosening. For the AMR items that cite generic note E, the LRA credits the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program to manage the aging effect for carbon steel structural bolting. The GALL Report recommends GALL Report AMP XI.S6, "Structures Monitoring," to ensure that these aging effects are adequately managed. GALL Report AMP XI.S6 recommends visual inspection of structural bolting, at a frequency not to exceed 5 years, to manage aging.

The staff's evaluation of the applicant's Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program is documented in SER Section 3.0.3.2.5. The staff noted that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program proposes to manage the aging of carbon steel structural bolting through the use of visual inspections. In its review of components associated with item 3.5.1-88 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program acceptable because visual inspections for cranes are performed in accordance with ASME Code B30 standards, which require inspections more frequently than the 5-year interval recommended in GALL Report AMP XI.S6.

The staff concludes that for LRA item 3.5.1-88, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.2.1.6 Loss of Material due to Pitting and Crevice Corrosion

LRA Table 3.5-1, item 3.5.1-93 addresses stainless steel and aluminum support members, welds, bolted connections, and support anchorage to building structures exposed to atmosphere/weather 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 ASME Section XI, Subsection IWF Program to manage the aging effect for stainless steel bolting and ASME Code Class 2 and 3 supports. The GALL Report recommends GALL Report AMP XI.S6, "Structures Monitoring," to ensure that these aging effects are adequately managed. However, the staff notes that SRP-LR Table 3.5-1, item 3.5.1-91 also addresses steel support members, welds, bolted connections, and support anchorage to building structures exposed to atmosphere/weather which will be managed for loss of material caused by pitting and crevice corrosion. Although the referenced GALL Report items in SRP-LR Table 3.5.1, item 3.5.1-91 do not include stainless steel as a material for the identified aging effect, the staff agrees that the ASME Section XI, Subsection IWF Program would be an acceptable program to manage this aging effect for stainless steel bolting and ASME Code Class 2 and 3 supports.

The staff's evaluation of the applicant's ASME Section XI, Subsection IWF Program is documented in SER Section 3.0.3.2.16. The staff notes that the ASME Section XI, Subsection IWF Program proposes to manage the aging of supports for Class 1, 2, and 3 piping and components through the use of periodic visual examinations. The staff also notes that the ASME Section XI, Subsection IWF Program will be enhanced to specify that whenever replacement of bolting is required, bolting material, installation torque or tension, and use of lubricants and sealants are in accordance with the applicable EPRI guidelines, ASTM standards, AISC specifications, and NUREG recommendations to prevent or mitigate degradation and failure of safety-related bolting caused by SCC.

In its review of components associated with item 3.5.1-93 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the ASME Section XI, Subsection IWF Program acceptable because, although the GALL Report doesn't list stainless steel as a material in the evaluation of components associated with item 3.5.1-93, the staff would expect ASME Code Class 2 and 3 supports to be managed by the ASME Section XI, Subsection IWF Program.

The staff concludes that for LRA item 3.5.1-93, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.2.1.7 No Aging Effects Requiring Management

LRA Table 3.5-1, item 3.5.1-95 addresses aluminum, galvanized steel and stainless steel support members, welds, bolted connections, and support anchorage to building structure exposed to air-indoor uncontrolled and states that there are no AERM and no AMP is proposed. The GALL Report states that there are no AERM and no AMP is proposed for this component group.

During its review of components associated with item 3.5.1-95, for which the applicant cited generic note A, the staff noted that the LRA cites this item for stainless steel components exposed to borated water leakage in addition to uncontrolled indoor air. The staff also noted that there are items in other sections of the GALL Report, such as items EP-19 or AP-18, which state that stainless steel components exposed to air with borated water leakage have no AERM. Although item 3.5.1-95 is for stainless steel components exposed to uncontrolled indoor air, the staff finds the applicant's use of this item for stainless steel components exposed to borated water leakage acceptable because the conclusion that there are no AERM for this component group is consistent with the GALL Report recommendations documented in other items.

The staff noted that there are stainless steel ASME Code Class 1, 2, and 3 supports and mechanical equipment supports exposed to uncontrolled indoor air or borated water leakage in LRA Table 3.5.2-12, which cite item 3.5.1-95 and state that there are no AERM and no AMP is proposed. However, GALL Report AMP XI.S3, "ASME Section XI, Subsection IWF," covers the inspection criteria for ASME Code Class 1, 2, and 3 component supports for license renewal and recommends visual inspection of a sample of supports. It was unclear to the staff why these ASME Code Class 1, 2, and 3 supports have no AERM, given that they appear to be within the scope of the ASME Section XI, Subsection IWF Program. By letter dated August 16, 2012, the staff issued RAI 3.5.1.095-1 requesting that the applicant provide justification for why the supports are not being managed using the ASME Section XI, Subsection IWF Program; or provide an appropriate program to manage the aging effects.

In its response dated September 20, 2012, the applicant stated that a single support may be constructed of more than one material and, therefore, have multiple entries in LRA Table 3.5.2-12. The applicant stated that the scope of the ASME Code Section XI, Subsection IWF Program and samples selected for inspection are based on individual component supports. The applicant also stated that even though part of a support may not require aging management, the entire support is within the program. The applicant confirmed that all ASME Code Class 1, 2, and 3 supports are within the scope of license renewal and are being managed by the ASME Section XI, Subsection IWF Program. The staff finds the applicant's response acceptable because all ASME Code Class 1, 2, and 3 supports are being managed by the ASME Section XI, Subsection IWF Program. The staff's concern described in RAI 3.5.1.095-1 is resolved.

The staff concludes that for LRA item 3.5.1-95, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation is Recommended

In LRA Section 3.5.2.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the containments, structures, and component supports components and provides information concerning how it will manage the following aging effects:

(1) PWR and BWR containments:

- cracking and distortion due to increased stress levels from settlement; reduction of foundation strength and cracking due to differential settlement and erosion of porous concrete subfoundations
- reduction of strength and modulus 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 aggregates

(2) safety-related and other structures and component supports:

- aging management of inaccessible areas
- reduction of strength and modulus due to elevated temperature
- aging management of inaccessible areas for Group 6 structures
- cracking due to SCC and loss of material due to pitting and crevice corrosion
- cumulative fatigue damage due to fatigue

(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 GALL Report and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluations to determine whether it adequately addressed the issues further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.5.2.2. The staff's review of the applicant's further evaluation follows.

3.5.2.2.1 PWR and BWR Containments

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:

Cracking and Distortion Due to Increased Stress Levels from Settlement; Reduction of Foundation Strength, and Cracking Due to Differential Settlement and Erosion of Porous Concrete Subfoundations. LRA Section 3.5.2.2.1.1, associated with LRA Table 3.5-1, items 3.5.1-1 and 3.5.1-2, addresses concrete exposed to soil or water which will be managed for cracking due to settlement or cracking and loss of foundation strength due to erosion of porous concrete subfoundations by the Structures Monitoring Program or the ASME Section XI, Subsection IWL Program. The criteria in SRP-LR Section 3.5.2.2.1.1 states that cracking and distortion and reduction of foundation strength could occur for concrete and steel containments exposed to soil or water, and if a dewatering system is used to control settlement further evaluation is necessary. The applicant addressed the further evaluation criteria of the SRP-LR by stating that there are no porous subfoundations on the site and no permanent dewatering systems are installed or planned.

The staff's evaluation of the applicant's Structures Monitoring and ASME Section XI, Subsection IWL Programs is documented in SER Sections 3.0.3.2.17 and 3.0.3.1.12, respectively. The staff reviewed FSAR-SP Section 3.4.1.2 and FSAR-SA Section 2.4.13.5 and noted that no dewatering system was installed or planned. In its review of components associated with items 3.5.1-1 and 3.5.1-2, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the Structures Monitoring and ASME Section XI, Subsection IWL Programs is acceptable because these programs are the GALL Report recommended programs, and additional further evaluation is unnecessary since no permanent dewatering system is used on site.

Based on the programs identified, the staff concludes that the applicant meets the SRP-LR Section 3.5.2.2.1.1 criteria. For those items associated with LRA Section 3.5.2.2.1.1, the staff determined that the LRA is consistent with the GALL Report and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Reduction of Strength and Modulus Due to Elevated Temperature. LRA Section 3.5.2.2.1.2, associated with LRA Table 3.5-1, item 3.5.1-3, addresses reduction of strength and modulus due to elevated temperatures in concrete exposed to indoor or outdoor air. The applicant stated that this item is not applicable because containment concrete temperatures are maintained below the GALL Report limits of 66 °C (150 °F) for general areas and 93 °C (200 °F) for local areas. The staff reviewed LRA Sections 2.4.1 and 3.5, and the FSAR and finds that no in-scope containment concrete is exposed to elevated temperatures beyond the GALL Report limits; therefore, a plant-specific aging management program is not required and further evaluation of this aging effect is not necessary.

Loss of Material Due to General, Pitting and Crevice Corrosion. LRA Section 3.5.2.2.1.3, associated with LRA Table 3.5.1, items 3.5.1-4 through 3.5.1-7, addresses the following:

(1) *Steel Elements of Inaccessible Areas for all types of PWR and BWR Containments*. LRA Section 3.5.2.2.1.3.1, associated with LRA Table 3.5-1, item 3.5.1-4, addresses loss of material due to general, pitting ,and crevice corrosion in the steel elements (inaccessible areas). The applicant stated that this item is not applicable because Callaway is a PWR. The staff evaluated the applicant's claim by reviewing the LRA, SRP-LR and FSAR and finds the applicant's claim acceptable because this item is only applicable to BWRs.

LRA Section 3.5.2.2.1.3.1 associated with LRA Table 3.5.1 items 3.5.1-5, addresses steel elements (inaccessible areas): liner, liner anchors, and integral attachments exposed to plant indoor air which will be managed for loss of material by the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J Programs. The criteria in SRP-LR Section 3.5.2.2.1.3, item 1 states that loss of material due to general, pitting, and crevice corrosion could occur for steel elements of inaccessible areas for all types of PWR and BWR containments exposed to plant indoor air. The SRP-LR recommends further evaluation of plant-specific programs to manage this aging effect if corrosion is indicated by ASME Code Section XI, Subsection IWE examinations. GALL Report item II.A1.CP-98 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:

(i) 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.

(ii) 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.

(iii) 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.

(iv) 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 of the SRP-LR by stating that reinforced concrete structures were designed, constructed, and inspected in accordance with ACI and ASTM standards, which provide for a good quality, dense, well-cured, and low permeability concrete. The applicant stated that the mix proportions were established in accordance with ACI 301 and the mix designs contain an air-entraining admixture in accordance with ASTM C260, and maximum water content was controlled by placing the concrete at specified slumps. The staff reviewed the applicant's FSAR Section 3.8.1.6.1 and confirmed the properties of the concrete mix. The staff also noted that conveying and placement of the concrete was done in accordance with ACI 318 code, which meets many of the recommendations of ACI 201.2R by providing low permeability concrete using a low water-cement ratio based on minimum slump. The ACI 318 code provides requirements for concrete placement and curing to ensure the required concrete quality, durability, and strength are attained (concrete used in the construction of the reactor building shell and dome has a compressive strength of 6,000 psi at 90 days and the structural concrete used in the construction of the reactor building base slab, reactor cavity, instrumentation tunnel, and tendon access gallery has a

compressive strength of 5,000 psi at 90 days). Therefore, the staff finds that the applicant adequately addressed condition (i) above.

The applicant stated that the ASME Section XI, Subsection IWL Program identifies and manages any cracks in the containment concrete that could potentially provide a pathway for water to reach inaccessible portions of the steel containment liner. The applicant also stated that crack control was achieved through proper sizing, spacing, and distribution of reinforcing steel in accordance with ACI 318-71. The staff confirmed the applicant's statements by reviewing FSAR Section 3.8.1.2.2 and the ASME Section XI, Subsection IWL Program and finds that the applicant adequately addressed condition (ii) above, by ensuring that the concrete is monitored to ensure that it is free of cracks that may allow water to penetrate and seep onto the steel liner.

The LRA states that the applicant manages aging of the moisture barrier at the interface between the liner and the concrete with the ASME Section XI, Subsection IWE Program. However, by letter dated August 9, 2012, in response to RAI B2.1.26-1, the applicant stated that there is no moisture barrier seal at the interface between the containment liner and the internal concrete floor. The applicant revised the LRA to remove the statement that the ASME Section XI, Subsection IWE program manages aging of the moisture barrier between the liner and the concrete.

The applicant stated that its procedural controls ensure that borated water spills are not common, and when detected are cleaned up in a timely manner. This is consistent with the criteria recommended in the GALL Report. The staff finds that the applicant adequately addressed conditions (iii) and (iv) above.

The staff reviewed the applicant's operating experience associated with the ASME Section XI, Subsection IWE Program to determine if the examinations have discovered corrosion. The staff's independent review and the applicant's internal review did not find operating experience that indicated there was a corrosion issue, therefore a plant-specific program to manage loss of material caused by general, pitting, and crevice corrosion is not necessary.

The staff's evaluation of the applicant's ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J Programs are documented in SER Sections 3.0.3.2.15 and 3.0.3.1.13, respectively. In its review of components associated with item 3.5.1-5 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 IWE and 10 CFR Part 50, Appendix J Programs is acceptable because the applicant proposes to manage the aging of inaccessible areas of steel elements using the GALL Report recommended programs, and the applicant has satisfied the four conditions identified in GALL Report item II.A1.CP-98.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.5.2.2.1.3, item 1 criteria. For those items associated with LRA Section 3.5.2.2.1.3.1, 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).

(2) *Steel Torus Shell of Mark I Containments*. LRA Section 3.5.2.2.1.3.2, associated with LRA Table 3.5-1, item 3.5.1-6, addresses loss of material due to general, pitting and crevice corrosion in the steel torus shell of Mark I BWR containments exposed to either an air-indoor uncontrolled or treated water environment. The GALL Report recommends

GALL Report AMP XI.S1, "ASME Section XI, Subsection IWE," and GALL Report AMP XI.S4, "10 CFR Part 50, Appendix J," to manage for loss of material due to general, pitting, and crevice corrosion for this component group. The applicant stated that this item is not applicable because Callaway is a PWR with a prestressed concrete containment that does not use a steel torus shell. The staff evaluated the applicant's claim by reviewing LRA Sections 2.4.1 and 3.5 and finds it acceptable because Callaway is a PWR.

(3) *Steel Torus Ring Girders and Downcomers of Mark I Containments, Downcomers of Mark II Containments, and Interior Surface of Suppression Chamber Shell of Mark III Containments*. LRA Section 3.5.2.2.1.3.3, associated with LRA Table 3.5-1, item 3.5.1-7, addresses loss of material due to general, pitting and crevice corrosion in steel elements: torus ring girders; downcomers; suppression chamber shell (inner surface) of Mark I and Mark II BWR containments exposed to either an air-indoor uncontrolled or treated water environment. The GALL Report recommends GALL Report AMP XI.S1, "ASME Section XI, Subsection IWE," and GALL Report AMP XI.S4, "10 CFR Part 50, Appendix J," to manage for loss of material caused by general, pitting, and crevice corrosion for this component group. The applicant stated that this item is not applicable because Callaway is a PWR with a prestressed concrete containment that does not use these steel components. The staff evaluated the applicant's claim by reviewing LRA Sections 2.4.1 and 3.5 and finds it acceptable because Callaway is a PWR.

Loss of Prestress Due to Relaxation, Shrinkage, Creep, and Elevated Temperature. LRA Section 3.5.2.2.1.4, associated with LRA Table 3.5-1, item 3.5.1-8, addresses steel prestressing tendons exposed to either an air-indoor uncontrolled or air-outdoor environment. LRA Section 3.5.2.2.1.4 states that loss prestress forces caused by relaxation, shrinkage, creep, and elevated temperature for prestressed concrete containments is a TLAA and that the evaluation of this TLAA is addressed in LRA Section 4.5. This is consistent with SRP-LR Section 3.5.2.2.1.4 and is, therefore, acceptable.

Based on its review, the staff concludes that the applicant has met the SRP-LR Section 3.5.2.2.1.4 criteria. For those items that apply to LRA Section 3.5.2.2.1.4, the staff determined that the LRA is consistent with the GALL Report and 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). SER Section 4.5 documents the staff's review of the applicant's evaluation of the TLAAs for these components.

Cumulative Fatigue Damage. LRA Section 3.5.2.2.1.5, associated with LRA Table 3.5-1, item 3.5.1-9, addresses the TLAAs (if CLB fatigue analyses exist) of suppression pool steel shells (including welded joints) and penetrations (including penetration sleeves, dissimilar metal welds, and penetration bellows) for all types of PWR and BWR containments and BWR vent header, vent line bellows, and downcomers exposed to either an uncontrolled indoor air, treated water, or outdoor air environment that will be managed for cumulative fatigue damage due to cyclic loading by a TLAA.

LRA Section 3.5.2.2.1.5 states that this analysis is associated with a TLAA and that the evaluation of this TLAA is addressed in Section 4.6.1 and 4.6.2. This is consistent with SRP-LR Section 3.5.2.2.1.5 and is, therefore, acceptable.

Based on its review, the staff concludes that the applicant meets SRP-LR Section 3.5.2.2.1.5 criteria. For those items that apply to LRA Section 3.5.2.2.1.5, 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 function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). SER Section 4.6 documents the staff's review of the applicant's evaluation of the TLAAs for these components.

Cracking Due to Stress Corrosion Cracking. LRA Section 3.5.2.2.1.6, associated with LRA Table 3.5-1, item 3.5.1-10, addresses steel penetration sleeves, penetration bellows, exposed to air-indoor uncontrolled which will be managed for cracking by the 10 CFR Part 50 Appendix J and ASME Section XI, Subsection IWE Programs.

The applicant stated that it does not have any stainless steel penetration bellows in scope as part of the containment pressure boundary. The applicant also stated that stainless steel high energy pipes that penetrate the containment are connected to carbon steel penetration sleeves with dissimilar metal welds. The applicant further stated that plant operating experience has not identified any SCC associated with these welds.

The criteria in SRP-LR Section 3.5.2.2.1.6 states that cracking due to SCC of stainless steel penetration bellows and dissimilar metal welds could occur in all types of PWR and BWR containments. The SRP-LR also states that the existing program relies on ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J Programs to manage this aging effect. The SRP-LR further states that the GALL Report recommends further evaluation of additional appropriate examinations/evaluations implemented to detect these aging effects for stainless steel penetration bellows and dissimilar metal welds.

The staff's review of the applicant's ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J Programs and its evaluations are documented in SER Sections 3.0.3.2.15 and 3.0.3.1.13, respectively. The staff finds that the credited programs are adequate to manage the aging effect because: (a) the applicant's use of the programs to manage the aging effect is consistent with the recommendation in the GALL Report and (b) the applicant's operating experience review results indicate that there have been no occurrences of SCC in the components which supports the applicant's claim that no augmented or additional inspections are required to manage the aging effect for the components. On the basis of its review, the staff finds that the applicant's AMR results are consistent with the GALL Report, and the applicant has met the further evaluation criteria in SRP-LR Section 3.5.2.2.1.6.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.5.2.2.1.6 criteria. For those items associated with LRA Section 3.5.2.2.1.6, 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 function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Loss of Material (Scaling, Spalling) and Cracking Due to Freeze-Thaw. LRA Section 3.5.2.2.1.7, associated with LRA Table 3.5-1, item 3.5.1-11, addresses loss of material and cracking due to freeze-thaw for inaccessible concrete exposed to outdoor-air, soil, or water. The criteria in SRP-LR Section 3.5.2.2.1.7 states that loss of material and cracking caused by freeze-thaw could occur for concrete exposed to outdoor-air, soil, or water and that evaluation is recommended for plants located in moderate to severe weathering conditions. The SRP-LR also states that a plant-specific program is not required if documented evidence confirms the

existing concrete had air content between three and eight percent, and subsequent inspection of accessible areas did not exhibit degradation related to freeze-thaw. The applicant addressed the further evaluation criteria of the SRP-LR by stating that a plant-specific AMP is not required and the aging effect is not applicable because the concrete mix designs contained an air-entraining admixture capable of entraining three to six percent air and plant operating experience has not identified any aging effects related to freeze-thaw in accessible areas.

The staff reviewed FSAR-SP Section 3.8.1.6.1.1 and confirmed that appropriate air-entrainment was used in the concrete mix design. The staff also conducted an independent review of the applicant's operating experience and did not identify any freeze-thaw related concrete degradation. In its review of components associated with item 3.5.1-11, the staff finds the applicant's determination that this aging effect is not applicable acceptable because the appropriate air content was used in the concrete and there is no site-specific operating experience with freeze-thaw degradation.

Cracking Due to Expansion from Reaction with Aggregates. LRA Section 3.5.2.2.1.8, associated with LRA Table 3.5-1, item 3.5.1-12, addresses cracking caused by expansion from reaction with aggregates for inaccessible concrete exposed to any environment. The criteria in SRP-LR Section 3.5.2.2.1.8 states that further evaluation is recommended to determine if a plant-specific AMP is required to manage this aging effect. The SRP-LR also states that a plant-specific program is not required if: (1) investigations, tests, and petrographic examinations of aggregates performed in accordance with ASTM C295 and other ASTM reactivity tests can demonstrate the aggregates do not adversely react with concrete, or (2) for potentially reactive aggregates, the structure was constructed in accordance with ACI 318. The applicant addressed the further evaluation criteria of the SRP-LR by stating that a plant-specific AMP is not required because a petrographic examination of the aggregates was conducted in accordance with ASTM C295 and the concrete was constructed in accordance with applicable ACI and ASTM standards.

The staff reviewed FSAR-SP Section 3.8.1.2.2 and Table 3.2-1 and confirmed that the aggregates were tested for reactivity in accordance with ASTM C289, a petrographic analysis was conducted per ASTM C295, and the structures were constructed in accordance with ACI 318. In its review of components associated with item 3.5.1-12, the staff finds that the applicant has met the further evaluation criteria, and the applicant's determination that a plant-specific program is not necessary is acceptable because the appropriate ASTM standards were followed and the concrete was constructed in accordance with ACI 318.

Based on its review, the staff concludes that the applicant meets SRP-LR Section 3.5.2.2.1.8 criteria. For those items associated with LRA Section 3.5.2.2.1.8, the staff determined that the LRA is consistent with the GALL Report and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Increase in Porosity and Permeability Due to Leaching of Calcium Hydroxide and Carbonation. LRA Section 3.5.2.2.1.9, associated with LRA Table 3.5-1, items 3.5.1-13 and 3.5.1-14, addresses increase in porosity and permeability caused by leaching of calcium hydroxide and carbonation of inaccessible concrete exposed to flowing water. The criteria in SRP-LR Section 3.5.2.2.1.9 states that further evaluation is recommended if leaching is observed in accessible areas. The SRP-LR also states that a plant-specific program is not required if: (1) there is evidence in the accessible areas that the flowing water has not caused leaching and carbonation, or (2) evaluation determined that the observed leaching of calcium hydroxide and

carbonation in accessible areas has no impact on the intended function of the concrete structure. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the concrete structures were designed, constructed, and inspected in accordance with ACI and ASTM standards, which provide for a good quality, dense well-cured and low permeability concrete. However, no discussion was provided about operating experience with leaching of accessible concrete. Therefore, by letter dated July 9, 2012, the staff issued RAI 3.5.2.2.1.9-1 requesting that the applicant provide a summary of any operating experience with concrete leaching and an appropriate AMP or evaluation to address any concrete leaching.

In its response dated August 9, 2012, the applicant stated that no significant leaching has occurred in structures within the scope of license renewal. The applicant stated that the only identified leaching has been minor, with any significant water in-leakage occurring through degraded elastomeric seals, which have been evaluated. The applicant also stated that an engineering evaluation was conducted on the minor leaching identified in the tendon gallery. The applicant stated that the substance was analyzed and found to be composed of sodium and potassium carbonate with no calcium or iron. In addition, the applicant stated that a visual inspection of the wall did not identify concrete cracking or any signs of rust or corrosion. The applicant further stated that the tendon gallery is included in the scope of the Structures Monitoring Program and that the program will continue to monitor structures within the scope of license renewal for leaching during the period of extended operation.

The staff reviewed the applicant's response and noted that only minor indications of leaching have been identified. The staff also noted that the Structures Monitoring Program inspects for indications of leaching. The staff finds the applicant's response acceptable because it explains that the identified tendon gallery leaching was reviewed, evaluated, and found to have no impact on the function of the structure. The response further explains that the Structures Monitoring Program, which is the GALL Report recommended program, will monitor for this aging effect during the period of extended operation. The staff's concern described in RAI 3.5.2.2.1.9-1 is resolved.

In its review of components associated with items 3.5.1-13 and 3.5.1-14, the staff finds that 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 program is the GALL Report recommended program, and because the applicant stated that it does not have any operating experience with significant leaching that would impact the intended function of a structure. The staff finds that an additional plant-specific program is unnecessary for inaccessible concrete since an evaluation determined that the observed minor leaching in accessible areas has no impact on the intended function of the concrete structure.

Based on its review, the staff concludes that the applicant meets SRP-LR Section 3.5.2.2.1.9 criteria. For those items associated with LRA Section 3.5.2.2.1.9, the staff concludes that the LRA is consistent with the GALL Report and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2.2. 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:

Aging Management of Inaccessible Areas.

(1) *Loss of Material (Spalling, Scaling) and Cracking Due to Freeze-Thawin Below-Grade*.

Inaccessible Concrete Areas of Groups 1-3, 5, and 7-9 Structures. LRA Section 3.5.2.2.2.1.1, associated with LRA Table 3.5-1, item 3.5.1-42, addresses loss of material and cracking due to freeze-thaw for inaccessible concrete exposed to outdoor-air. The criteria in SRP-LR Section 3.5.2.2.2.1, item 1 states that loss of material and cracking caused by freeze-thaw could occur in below-grade inaccessible concrete areas and that evaluation is recommended for plants located in moderate to severe weathering conditions. The SRP-LR also states that a plant-specific program is not required if documented evidence confirms the existing concrete had air content between three and eight percent, and subsequent inspection of accessible areas did not exhibit degradation related to freeze-thaw. The applicant addressed the further evaluation criteria of the SRP-LR by stating that a plant-specific AMP is not required because the concrete mix designs contained an air-entraining admixture capable of entraining three to six percent air and plant operating experience has not identified any aging effects related to freeze-thaw in accessible areas.

The staff reviewed FSAR-SP Section 3.8.1.6.1 and confirmed that appropriate air-entrainment was used in the concrete mix design. The staff also conducted an independent review of the applicant's operating experience and did not identify any freeze-thaw related concrete degradation. In its review of components associated with item 3.5.1-42, the staff finds that the applicant has met the further evaluation criteria, and the applicant's determination that a plant-specific program is not necessary is acceptable because the appropriate air content was used in the concrete and there is no site-specific operating experience with freeze-thaw degradation.

Based on its review, the staff concludes that the applicant meets SRP-LR Section 3.5.2.2.2.1, item 1 criteria. For those items associated with LRA Section 3.5.2.2.2.1.1, 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 function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(2) *Cracking Due to Expansion and Reaction with Aggregates of Groups 1-5 and 7-9 Structures*. LRA Section 3.5.2.2.2.1.2, associated with LRA Table 3.5-1, item 3.5.1-43, addresses cracking due to expansion from reaction with aggregates for inaccessible concrete exposed to any environment. The criteria in SRP-LR Section 3.5.2.2.2.1, item 2 states further evaluation is recommended to determine if a plant-specific AMP is required to manage this aging effect. The SRP-LR also states that a plant-specific program is not required if: (1) investigations, tests, and petrographic examinations of aggregates performed in accordance with ASTM C295 and other ASTM reactivity tests can demonstrate the aggregates do not adversely react with concrete, or (2) for potentially reactive aggregates, the structure was constructed in accordance with ACI 318. The applicant addressed the further evaluation criteria of the SRP-LR by stating that a plant-specific AMP is not required because a petrographic examination of the aggregates was conducted in accordance with ASTM C295 and the concrete was constructed in accordance with applicable ACI and ASTM standards.

The staff reviewed FSAR-SP Section 3.8.1.2.2 and Table 3.2-1 and confirmed that the aggregates were tested for reactivity in accordance with ASTM C289, a petrographic analysis was conducted per ASTM C295, and the structures were constructed in

accordance with ACI 318. In its review of components associated with item 3.5.1-43, the staff finds that the applicant has met the further evaluation criteria, and the applicant's determination that a plant-specific program is not necessary is acceptable because the appropriate ASTM standards were followed and the concrete was constructed in accordance with ACI 318.

Based on its review, the staff concludes that the applicant meets SRP-LR Section 3.5.2.2.2.1, item 2 criteria. For those items associated with LRA Section 3.5.2.2.2.1.2, 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 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) *Cracking and Distortion Due to Increased Stress Levels from Settlement for Below-Grade Inaccessible Concrete Areas of Structures for all Groups and Reduction in Foundation Strength and Cracking Due to Differential Settlement and Erosion of Porous Concrete Subfoundations in Below-Grade Inaccessible Concrete Areas for Groups 1-3, and 5-9 Structures.* LRA Section 3.5.2.2.2.1.3, associated with LRA Table 3.5-1, items 3.5.1-44 and 3.5.1-46, addresses concrete exposed to soil or water which will be managed for cracking caused by settlement or cracking and loss of foundation strength caused by erosion of porous concrete subfoundations by the Structures Monitoring Program. The criteria in SRP-LR Section 3.5.2.2.2.1, item 3 states that cracking and distortion and reduction of foundation strength could occur for concrete structures exposed to soil or water, and if a dewatering system is used to control settlement further evaluation is necessary. The applicant addressed the further evaluation criteria of the SRP-LR by stating that Callaway is a PWR and there are no porous subfoundations on the site and no permanent dewatering systems are installed or planned.

The staff evaluations of the applicant's Structures Monitoring is documented in SER Sections 3.0.3.2.17. The staff reviewed FSAR-SP Section 3.4.1.2 and FSAR-SA Section 2.4.13.5 and noted that no dewatering system was installed or planned. The staff also noted that Callaway is a PWR and has no porous concrete foundations; therefore, items 3.5.1-45 and 3.5.1-46 are not applicable. In its review of components associated with items 3.5.1-44 and 3.5.1-46, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the Structures Monitoring Program is acceptable because the program is the GALL Report recommended program. Additional further evaluation is unnecessary since no permanent dewatering system is used on site.

Based on the programs identified, the staff concludes that the applicant meets SRP-LR Section 3.5.2.2.2.1, item 3 criteria. For those items associated with LRA Section 3.5.2.2.2.1.3, 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 function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(4) *Increase in Porosity and Permeability, and Loss of Strength Due to Leaching of Calcium Hydroxide and Carbonation 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 3.5.1-47, addresses increase in porosity and permeability due to leaching of calcium hydroxide and carbonation of inaccessible concrete exposed to flowing water. The criteria in SRP-LR Section 3.5.2.2.2.1, item 4 states that further evaluation is recommended if leaching is observed in accessible areas. The SRP-LR also states that a plant-specific program is

not required if: (1) there is evidence in the accessible areas that the flowing water has not caused leaching and carbonation, or (2) evaluation determined that the observed leaching of calcium hydroxide and carbonation in accessible areas has no impact on the intended function of the concrete structure. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the concrete structures were designed, constructed, and inspected in accordance with ACI and ASTM standards, which provide for a good quality, dense, well-cured, and low permeability concrete. However, no discussion was provided about operating experience associated with leaching of accessible concrete. Therefore, by letter dated July 9, 2012, the staff issued RAI 3.5.2.2.1.9-1 requesting that the applicant provide a summary of any operating experience associated with concrete leaching and an appropriate AMP or evaluation to address any concrete leaching.

In its response dated August 9, 2012, the applicant stated that no significant leaching has occurred in structures within the scope of license renewal. The applicant stated that the only identified leaching has been minor, with any significant water in-leakage occurring through degraded elastomeric seals, which have been evaluated. The applicant also stated that an engineering evaluation was conducted on the minor leaching identified in the tendon gallery and the substance was analyzed and found to be composed of sodium and potassium carbonate with no calcium or iron. The applicant further stated that a visual inspection of the wall did not identify concrete cracking or any signs of rust or corrosion. The applicant also stated that the tendon gallery is included in the scope of the Structures Monitoring Program and that the program will continue to monitor structures within the scope of license renewal for leaching during the period of extended operation.

The staff reviewed the applicant's response and noted that only minor indications of leaching have been identified. The staff also noted that the Structures Monitoring Program inspects for indications of leaching. The staff finds the applicant's response acceptable because it explains that the identified tendon gallery leaching was reviewed, evaluated, and found to have no impact on the function of the structure. The response further explains that the Structures Monitoring Program, which is the GALL Report recommended program, will monitor for this aging effect during the period of extended operation. The staff's concern described in RAI 3.5.2.2.1.9-1 is resolved.

In its review of components associated with items 3.5.1-47, the staff finds that 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 program is the GALL Report recommended program, and because the applicant stated that it does not have any operating experience with significant leaching that would impact the intended function of a structure. An additional plant-specific program is unnecessary for inaccessible concrete since an evaluation determined that the observed minor leaching in accessible areas has no impact on the intended function of the concrete structure.

Based on its review, the staff concludes that the applicant meets SRP-LR Section 3.5.2.2.2.1, item 4 criteria. For those items associated with LRA Section 3.5.2.2.2.1.4, 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 function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Reduction of Strength and Modulus Due to Elevated Temperature. LRA Section 3.5.2.2.2.2, associated with LRA Table 3.5-1, item 3.5.1-48, addresses reduction of strength and modulus

caused by elevated temperatures in concrete exposed to indoor air. The criteria in SRP-LR Section 3.5.2.2.2.2 states that further evaluation is recommended for any concrete elements that exceed specified temperature limits. The GALL Report provides the temperature limits as 66 °C (150 °F) for general areas and 93 °C (200 °F) for local areas. The SRP-LR also states that higher temperatures may be allowed if tests or calculations are provided to evaluate the reduction in strength and modulus of elasticity and these reductions are applied to the design calculations. The applicant addressed the further evaluation criteria of the SRP-LR by stating that concrete structures in the plant have been designed, or provided with appropriate cooling, to keep concrete temperatures below the specified limits, except for the area directly below the seal ring support, which is limited to 300 °F. The applicant further stated that an engineering evaluation was performed to ensure that the elevated temperature in the seal ring support concrete would not be detrimental to the ability of the concrete to perform its intended functions.

The staff reviewed the FSAR and noted that the concrete was maintained below the temperature limits identified in the GALL Report except for the seal ring support concrete. The staff reviewed FSAR-SP Section 3.8.3.4.2 and noted that the concrete temperature for the seal ring support is limited to 300 °F; however, the staff did not find any discussion of the possible reduction in strength and modulus caused by the higher temperatures. Therefore, by letter dated August 6, 2012, the staff issued RAI 3.5.2.2.2.2-1 requesting that the applicant provide information on how the high temperature was accounted for in the analysis of the seal ring support concrete.

In its response dated September 6, 2012, the applicant stated that an engineering calculation was performed to address the effects of the elevated temperature. The evaluation showed that the elevated temperatures could reduce the strength of the concrete to approximately 60 percent of the original design strength. The applicant explained that this reduced strength value was used to calculate allowable stresses, which were compared to the maximum design loads, and found to be acceptable.

The staff finds the applicant's response acceptable because the applicant identified an appropriate reduction in the strength of the concrete caused by the high temperatures and designed the structures accordingly. The staff's concern described in RAI 3.5.2.2.2.2-1 is resolved.

In its review of components associated with items 3.5.1-48, the staff finds that the applicant has met the further evaluation criteria, and the applicant's analysis is acceptable because concrete structures exposed to temperatures above the GALL Report limits have been analyzed and the proper strength reductions have been applied to the design calculations.

Based on its review, the staff concludes that the applicant meets SRP-LR Section 3.5.2.2.2.2 criteria. For those items associated with LRA Section 3.5.2.2.2.2, 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 function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Aging Management of Inaccessible Areas for Group 6 Structures. SRP-LR Section 3.5.2.2.2.3 addresses aging management of inaccessible areas for Group 6 structures (below-grade inaccessible concrete areas) and recommends further evaluation for inaccessible areas of certain Group 6 structure/aging effect combinations as identified below whether they are covered by inspections in accordance with the GALL Report AMP XI.S7, "RG 1.127, Inspection

of Water-Control Structures Associated with Nuclear Power Plants," or FERC/US Army Corps of Engineers dam inspection and maintenance procedures.

(1) *Loss of Material (Spalling, Scaling) and Cracking Due to Freeze-Thaw That Could Occur in Below-Grade Inaccessible Concrete Areas of Group 6 Structures*. LRA Section 3.5.2.2.2.3.1, associated with LRA Table 3.5-1, item 3.5.1-49, addresses loss of material and cracking due to freeze-thaw for inaccessible concrete exposed to outdoor-air. The criteria in SRP-LR Section 3.5.2.2.2.3, item 1 states that loss of material and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas and that further evaluation is recommended for plants located in moderate to severe weathering conditions. The SRP-LR also states that a plant-specific program is not required if documented evidence confirms the existing concrete had air content between three and eight percent, and subsequent inspection of accessible areas did not exhibit degradation related to freeze-thaw. The applicant addressed the further evaluation criteria of the SRP-LR by stating that a plant-specific aging management program is not required because the concrete mix designs contained an air-entraining admixture capable of entraining three to six percent air and plant operating experience has not identified any aging effects related to freeze-thaw in accessible areas.

The staff reviewed FSAR-SP Section 3.8.1.6.1 and confirmed that appropriate air-entrainment was used in the concrete mix design. The staff also conducted an independent review of the applicant's operating experience and did not identify any freeze-thaw related concrete degradation. In its review of components associated with item 3.5.1-49, the staff finds that the applicant has met the further evaluation criteria, and the applicant's determination that a plant-specific program is not necessary is acceptable because the appropriate air content was used in the concrete and there is no site-specific operating experience with freeze-thaw degradation.

Based on its review, the staff concludes that the applicant meets SRP-LR Section 3.5.2.2.2.3, item 1 criteria. For those items associated with LRA Section 3.5.2.2.2.3.1, 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 function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(2) *Cracking Due to Expansion and Reaction with Aggregates That Could Occur in Below-Grade Inaccessible Concrete Areas of Group 6 Structures*. LRA Section 3.5.2.2.2.3.2, associated with LRA Table 3.5-1, item 3.5.1-50, addresses cracking due to expansion from reaction with aggregates for inaccessible concrete exposed to any environment. The criteria in SRP-LR Section 3.5.2.2.2.3, item 2 states that further evaluation is recommended to determine if a plant-specific aging management program is required to manage this aging effect. The SRP-LR also states that a plant-specific program is not required if: (1) investigations, tests, and petrographic examinations of aggregates performed in accordance with ASTM C295 and other ASTM reactivity tests can demonstrate the aggregates do not adversely react with concrete, or (2) for potentially reactive aggregates, the structure was constructed in accordance with ACI 318. The applicant addressed the further evaluation criteria of the SRP-LR by stating that a plant-specific aging management program is not required because a petrographic examination of the aggregates was conducted in accordance with ASTM C295 and the concrete was constructed in accordance with applicable ACI and ASTM standards.

The staff reviewed FSAR-SP Section 3.8.1.2.2 and Table 3.2-1 and confirmed the aggregates were tested for reactivity in accordance with ASTM C289, a petrographic analysis was conducted per ASTM C295, and the structures were constructed in accordance with ACI 318. In its review of components associated with item 3.5.1-50, the staff finds that the applicant has met the further evaluation criteria, and the applicant's determination that a plant-specific program is not necessary is acceptable because the appropriate ASTM standards were followed and the concrete was constructed in accordance with ACI 318.

Based on its review, the staff concludes that the applicant meets SRP-LR Section 3.5.2.2.2.3, item 2 criteria. For those items associated with LRA Section 3.5.2.2.2.3.2, 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 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) *Increase in Porosity and Permeability and Loss of Strength Due to Leaching of Calcium Hydroxide and Carbonation That Could Occur in Below-Grade Inaccessible Concrete Areas of Group 6 Structures*. LRA Section 3.5.2.2.2.3.3, associated with LRA Table 3.5-1, item 3.5.1-51, addresses increase in porosity and permeability due to leaching of calcium hydroxide and carbonation of inaccessible concrete elements of Group 6 structures exposed to flowing water. The criteria in SRP-LR Section 3.5.2.2.2.3, item 3 states that further evaluation is recommended if leaching is observed in accessible areas. The SRP-LR also states that a plant-specific program is not required if: (1) there is evidence in the accessible areas that the flowing water has not caused leaching and carbonation, or (2) evaluation determined that the observed leaching of calcium hydroxide and carbonation in accessible areas has no impact on the intended function of the concrete structure. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the concrete structures were designed, constructed, and inspected in accordance with ACI and ASTM standards, which provide for a good quality, dense well-cured and low permeability concrete. However, no discussion was provided about operating experience with leaching of accessible concrete. Therefore, by letter dated July 9, 2012, the staff issued RAI 3.5.2.2.1.9-1 requesting that the applicant provide a summary of any operating experience with concrete leaching and provide an appropriate AMP or evaluation to address any concrete leaching.

In its response dated August 9, 2012, the applicant stated that no significant leaching has occurred in structures within the scope of license renewal. The applicant stated that the only identified leaching has been minor, with any significant water in-leakage occurring through degraded elastomeric seals, which have been evaluated. The applicant also stated that an engineering evaluation was conducted on the minor leaching identified in the tendon gallery and the substance was analyzed and found to be composed of sodium and potassium carbonate with no calcium or iron. The applicant further stated that a visual inspection of the wall did not identify concrete cracking or any signs of rust or corrosion. The applicant also stated that the tendon gallery is included in the scope of the Structures Monitoring Program and that the program will continue to monitor structures within the scope of license renewal for leaching during the period of extended operation.

The staff reviewed the applicant's response and noted that only minor indications of leaching have been identified. The staff also noted that the Structures Monitoring Program inspects for indications of leaching. The staff finds the applicant's response

acceptable because it explains that the identified tendon gallery leaching was reviewed, evaluated, and found to have no impact on the function of the structure. The response further explains that the Structures Monitoring Program, which is the GALL Report recommended program, will monitor for this aging effect during the period of extended operation. The staff's concern described in RAI 3.5.2.2.1.9-1 is resolved.

In its review of components associated with item 3.5.1-51, the staff finds that 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 program is the GALL Report recommended program, and because the applicant stated that it does not have any operating experience with significant leaching that would impact the intended function of a structure. The staff finds that an additional plant-specific program is unnecessary since an evaluation determined that the observed minor leaching in accessible areas has no impact on the intended function of the concrete structure.

Based on its review, the staff concludes that the applicant meets SRP-LR Section 3.5.2.2.2.3, item 3 criteria. For those items associated with LRA Section 3.5.2.2.2.3.3, 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 function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Cracking Due to Stress Corrosion Cracking, and Loss of Material Due to Pitting and Crevice Corrosion. LRA Section 3.5.2.2.2.4, associated with LRA Table 3.5-1, item 3.5.1-52, addresses cracking due to SCC and loss of material caused by pitting and crevice corrosion for Group 7 and 8 steel tank liners exposed to standing water. The applicant stated that this item is not applicable because the in-scope tank liners were evaluated as tanks with their mechanical systems and assigned GALL Report lines from Chapters VII and VIII; therefore, the GALL Report lines from Chapter III were not used. In its review, the staff noted that the in-scope tank liners were evaluated as tanks with their mechanical systems and assigned GALL Report lines from Chapters VII and VIII. The staff finds the applicant's claim acceptable because the applicant evaluated those items and will manage aging for tank liners.

Cumulative Fatigue Damage Due to Fatigue. LRA Section 3.5.2.2.2.5, associated with LRA Table 3.5-1, item 3.5.1-53, addresses cumulative fatigue damage due to cyclic loading in component support members, anchor bolts, and welds for Groups B1.1, B1.2, and B1.3 component supports exposed to air-indoor uncontrolled. The applicant stated these fatigue analyses are TLAAs identified for Class 1E electrical raceway supports which are described in LRA Section 4.3.

The staff reviewed LRA Section 3.5.2.2.2.5 against the criteria in SRP-LR Section 3.5.2.2.2.5, which states that fatigue of these structural components is a TLAA as defined in 10 CFR 54.3, and that these TLAAs are to be evaluated in accordance with the acceptance criteria in 10 CFR 54.21(c)(1). The staff reviewed the applicant's AMR items and determined that the AMR results are consistent with the recommendations in the GALL Report and SRP-LR for managing cumulative fatigue damage for these structural components.

The applicant also stated that based on its reviews to identify TLAAs in the CLB, there are no other fatigue analyses for component support members for Groups B1.1, B1.2, and B1.3. The staff reviewed the applicant's FSAR and confirmed that the applicant's CLB does not contain fatigue analyses for component support members, anchor bolts, and welds for Groups B1.1,

B1.2, and B1.3 that are required to be identified as TLAAs in accordance with 10 CFR 54.21(c)(1). Therefore, the staff finds the applicant's claim acceptable.

Based on its review, the staff concludes that the applicant has met the SRP-LR Section 3.5.2.2.2.5 criteria. For those items associated with LRA Section 3.5.2.2.2.5, 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 function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). SER Section 4.3 documents the staff's review of the applicant's evaluation of the TLAA for these structural components.

3.5.2.2.3 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA Program.

3.5.2.2.4 Operating Experience

SER Section 3.0.5, "Operating Experience for Aging Management Programs," documents the staff's evaluation of the applicant's consideration of operating experience of aging management programs.

3.5.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.5.2-1 through 3.5.2-12, 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 3.5.2-12, the applicant indicated, via notes F through J, that the combination of component type, material, environment, and AERM does not correspond to an AMR 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 AMR item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the AMR item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

3.5.2.3.1 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—Reactor Building—LRA Table 3.5.2-1

The staff reviewed LRA Table 3.5.2-1, which summarizes the results of AMR evaluations for the reactor building component groups.

Cementitious and Ceramic Fiber Fire Barrier Coatings and Wraps Exposed to Plant Indoor Air. In LRA Tables 3.5.2-1, 3.5.2-2, 3.5.2-3, 3.5.2-5, and 3.5.2-10, the applicant stated that cementitious and ceramic fiber fire barrier coatings and wraps exposed to plant indoor air will be managed for cracking and loss of material by the Fire Protection Program. 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. Although the GALL Report does not have any AMR items for non-metallic fire barriers, the staff noted that GALL Report AMP XI.M26, "Fire Protection," does include aging management of fire resistant materials, including fire wrapping and spray-on fireproofing, within the scope of the AMP. GALL Report AMP XI.M26 recommends that these materials be managed for cracking and loss of material. 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 3.0.3.2.6. The staff finds the applicant's proposal to manage aging using the Fire Protection Program acceptable because the program includes visual inspections of fire barriers of various material types which are capable of detecting degradation of the fire barrier prior to loss of intended function.

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

3.5.2.3.2 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—Control Building—LRA Table 3.5.2-2

The staff reviewed LRA Table 3.5.2-2, which summarizes the results of AMR evaluations for the control building component groups.

Cementitious and Ceramic Fiber Fire Barrier Coatings and Wraps Exposed to Plant Indoor Air. The staff's evaluation for cementitious and ceramic fiber fire barrier coatings and wraps exposed to plant indoor air which will be managed for cracking and loss of material by the Fire Protection Program and cite generic note J, is documented in SER Section 3.5.2.3.1.

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

3.5.2.3.3 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—Auxiliary Building—LRA Table 3.5.2-3

The staff reviewed LRA Table 3.5.2-3, which summarizes the results of AMR evaluations for the auxiliary building component groups.

Cementitious and Ceramic Fiber Fire Barrier Coatings and Wraps Exposed to Plant Indoor Air. The staff's evaluation for cementitious and ceramic fiber fire barrier coatings and wraps exposed to plant indoor air which will be managed for cracking and loss of material by the Fire Protection Program and cite generic note J, is documented in SER Section 3.5.2.3.1.

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

3.5.2.3.4 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—Turbine Building—LRA Table 3.5.2-4

The staff reviewed LRA Table 3.5.2-4, which summarizes the results of AMR evaluations for the turbine building component groups.

Cementitious Fire Barrier Coatings and Wraps Exposed to Plant Indoor Air. In LRA Table 3.5.2-4, the applicant stated that, for cementitious fire barrier coatings exposed to plant indoor air, there is no aging effect and no AMP is proposed. However, in a letter dated February 14, 2014, the applicant removed this AMR item from the LRA because it no longer has a fire barrier intended function, per the applicant's transition to a risk-informed, performance-based fire protection plan that incorporates NFPA-805. As a result, the staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the turbine building component groups are consistent with the GALL Report.

3.5.2.3.5 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—Diesel Generator Building—LRA Table 3.5.2-5

The staff reviewed LRA Table 3.5.2-5, which summarizes the results of AMR evaluations for the diesel generator building component groups.

Cementitious and Ceramic Fiber Fire Barrier Coatings and Wraps Exposed to Plant Indoor Air. The staff's evaluation for cementitious and ceramic fiber fire barrier coatings and wraps exposed to plant indoor air which will be managed for cracking and loss of material by the Fire Protection Program and cite generic note J, is documented in SER Section 3.5.2.3.1.

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

3.5.2.3.6 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—Miscellaneous In-Scope Structures—LRA Table 3.5.2-6

The staff reviewed LRA Table 3.5.2-6, which summarizes the results of AMR evaluations for the miscellaneous in-scope structures component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the miscellaneous in-scope structures component groups are consistent with the GALL Report.

3.5.2.3.7 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—In-Scope Tank Foundations and Structures—LRA Table 3.5.2-7

The staff reviewed LRA Table 3.5.2-7, which summarizes the results of AMR evaluations for the in-scope tank foundations and structures component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the in-scope tank foundations and structures component groups are consistent with the GALL Report.

3.5.2.3.8 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—Electrical Foundations and Structures—LRA Table 3.5.2-8

The staff reviewed LRA Table 3.5.2-8, which summarizes the results of AMR evaluations for the electrical foundations and structures component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the electrical foundations and structures component groups are consistent with the GALL Report.

3.5.2.3.9 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—Radwaste Building—LRA Table 3.5.2-9

The staff reviewed LRA Table 3.5.2-9, which summarizes the results of AMR evaluations for the radwaste building component groups.

Cementitious Fire Barrier Coatings and Wraps Exposed to Plant Indoor Air. In LRA Table 3.5.2-9, the applicant stated that, for cementitious fire barrier coatings exposed to plant indoor air, there is no aging effect and no AMP is proposed. However, in a letter dated February 14, 2014, the applicant removed this AMR item from the LRA because it no longer has a fire barrier intended function, per the applicant's transition to a risk-informed, performance-based fire protection plan that incorporates NFPA-805. As a result, the staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the radwaste building component groups are consistent with the GALL Report.

3.5.2.3.10 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—Fuel Building—LRA Table 3.5.2-10

The staff reviewed LRA Table 3.5.2-10, which summarizes the results of AMR evaluations for the fuel building component groups.

Cementitious and Ceramic Fiber Fire Barrier Coatings and Wraps Exposed to Plant Indoor Air. The staff's evaluation for cementitious and ceramic fiber fire barrier coatings and wraps exposed to plant indoor air which will be managed for cracking and loss of material by the Fire Protection Program and cite generic note J, is documented in SER Section 3.5.2.3.1.

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

3.5.2.3.11 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—Essential Service Water Structures—LRA Table 3.5.2-11

The staff reviewed LRA Table 3.5.2-11, which summarizes the results of AMR evaluations for the ESW structures component groups.

Fiber Glass Reinforced Plastic Fan Stack Exposed to Atmosphere or Weather. In LRA Table 3.5.2-11, the applicant stated that fiberglass reinforced plastic fan stack exposed to atmosphere/weather will be managed for cracking, blistering, and change in color by the Structures Monitoring 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. The staff notes that the GALL Report does not identify any applicable aging effects for glass; however, the polymers that are used to bind the glass material into the fiberglass matrix may be susceptible to aging. Based on its review of the Polymer Blends Handbook, Section 14.5, "Weathering of Polymer Blends," which states that the standard methods of assessing the performance of polymers exposed to UV radiation are gloss loss, chalking, color retention, cracking and crazing, and dirt retention, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination. However, the applicant's Structures Monitoring Program does not include specific guidance for monitoring or acceptance criteria of fiberglass reinforced plastic material. Therefore, by letter dated July 9, 2012, the staff issued RAI 3.5.2.11-2 requesting that the applicant explain what parameters will be monitored, and acceptance criteria will be used, for the aging management of fiberglass reinforced plastic components exposed to atmosphere/weather.

In its response dated August 9, 2012, the applicant stated that LRA Appendices A1.31 and B2.1.31 list cracking, blistering, and change in color as aging effects that are managed by the Structures Monitoring Program. The applicant further stated that plant procedures have been revised to specify that fiberglass reinforced plastic will be inspected, and any indication of cracking, blistering, or change in color will be evaluated for inclusion into Callaway's CAP.

Based on its review, the staff finds the applicant's response acceptable because the applicant has identified all applicable aging effects for the component, material, and environment combination, and has revised plant procedures to specify that any indication of cracking, blistering, or change in color be evaluated for inclusion into Callaway's CAP. The staff's concern described in RAI 3.5.2.11-2 is resolved.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.17. The staff finds the applicant's proposal to manage aging using the Structures Monitoring Program acceptable because: (a) the program description lists cracking, blistering, and change in color as aging effects that will be managed; (b) visual inspections will be completed at a period not to exceed 5 years; and (c) any indication of these listed aging effects will be evaluated for inclusion into Callaway's CAP.

Stainless Steel Structural Steel Exposed to a Submerged Environment. In LRA Table 3.5.2-11, the applicant stated that stainless steel structural steel exposed to a submerged environment will be managed for loss of material by the Structures 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 definition in GALL Report Chapter IX, which states that stainless steel is susceptible to loss of material and cracking, the staff determined the need for additional information. Therefore, by letter dated July 9, 2012, the staff issued RAI 3.5.2.11-1 requesting that the applicant describe the type, condition, and temperature of the water in which the stainless steel supports are submerged, explain why cracking is not an applicable aging effect, and explain how the Structures Monitoring Program will manage aging effects caused by loss of material. If it is determined that cracking needs to be managed, the staff also requested that the applicant identify an AMP and provide the technical justification for that AMP (i.e., inspection method, frequency, and acceptance criteria).

In its response dated August 9, 2012, the applicant stated that the submerged stainless steel components are embedded in the surface of the concrete in the ESW structures, and are exposed to raw water that passes through the pumphouse from the retention pond at ambient temperatures. The applicant also stated that the water in which these components are submerged is not heated above atmospheric temperatures, and it is refreshed on a regular basis; therefore, cracking is not an aging effect requiring management for these components. The applicant further stated that these components are monitored by the Structures Monitoring Program. In addition, the applicant stated that the pumphouse bays are dewatered on a frequency of approximately every 5 years, timed to coincide with plant outages, at which time a visual examination of the structural components is performed.

Based on its review, the staff finds the applicant's response acceptable because the submerged environment, for which these stainless steel structural steel components are exposed, would not be conducive to cracking of stainless steel components, and the applicant has identified all credible aging effects for this component, material, and environment combination. The staff also finds the applicants response acceptable because visual examination of the structural components is performed in a dewatered state, at a frequency consistent with the recommendations in GALL Report AMP XI.S6. The staff's concern described in RAI 3.5.2.11-1 is resolved.

The staff's evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.17. The staff finds the applicant's proposal to manage aging using the Structures Monitoring Program acceptable because the pumphouse bays are dewatered every 5 years and visually examined at a frequency consistent with recommendations in the GALL Report.

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

3.5.2.3.12 Containments, Structures, and Component Supports—Summary of Aging Management Evaluation—Supports—LRA Table 3.5.2-12

The staff reviewed LRA Table 3.5.2-12, which summarizes the results of AMR evaluations for the supports component groups. The staff's review did not identify any AMR items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for the supports component groups are consistent with the GALL Report.

3.5.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the structures and component supports within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6 Aging Management of Electrical and Instrumentation and Controls

This section of the SER documents the staff's review of the applicant's AMR results for the electrical and instrumentation and control (I&C) components of:

- cable connections (metallic parts)
- connectors
- high voltage insulators
- insulated cable and connections
- switchyard bus and connections
- terminal blocks
- transmission conductors
- transmission connections
- electrical equipment subject to 10 CFR 50.49 EQ requirements
- metal enclosed bus

3.6.1 Summary of Technical Information in the Application

LRA Section 3.6 provides AMR results for the electrical and I&C components. LRA Table 3.6-1, "Summary of Aging Management Programs 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 and I&C components.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.6.2 Staff Evaluation

The staff reviewed LRA Section 3.6 to determine if the applicant provided sufficient information to demonstrate that the effects of aging for the electrical and I&C components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will 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 of AMPs to ensure the applicant's claim that certain AMPs were consistent with the GALL Report. The purpose of this audit was to examine the applicant's AMPs and related documentation and to confirm the applicant's claim of consistency with the corresponding GALL Report AMPs. The staff did not repeat its review of the matters described in the GALL Report. The staff's evaluations of the AMPs are documented in SER Section 3.0.3.

The staff reviewed the AMRs to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did confirm that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. Details of the staff's evaluation are discussed in SER Section 3.6.2.1.

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

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 3.6.2.3.

For SSCs that the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR items and the plant's operating experience to confirm the applicant's claims.

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.

The staff's review of the electrical and I&C component groups followed any one of several approaches. One approach, documented in SER Section 3.6.2.1, reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.6.2.2, reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.6.2.3, reviewed AMR results for components that the applicant indicated are not consistent with or not addressed in the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the electrical and I&C components is documented in SER Section 3.0.3.

Table 3.6-1 Staff Evaluation for Electrical and I&C in the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Electrical equipment subject to 10 CFR 50.49 EQ requirements composed of Various polymeric and metallic materials exposed to Adverse localized environment caused by heat, radiation, oxygen, moisture, or voltage (3.6.1-1)	Various aging effects caused by various mechanisms in accordance with 10 CFR 50.49	EQ is a time-limited aging analysis (TLAA) to be evaluated for the period of extended operation. See the Standard Review Plan, Section 4.4, "Environmental Qualification (EQ) of Electrical Equipment," for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1)(i) and (ii). See Chapter X.E1, "Environmental Qualification (EQ) of Electric Components," of this report for meeting the requirements of 10 CFR 54.21(c)(1)(iii).	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.6.2.2.1)
High-voltage insulators composed of Porcelain; malleable iron; aluminum; galvanized steel; cement exposed to Air – outdoor (3.6.1-2)	Loss of material caused by mechanical wear caused by wind blowing on transmission conductors	A plant-specific aging management program is to be evaluated	Yes	Not applicable	Not applicable to Callaway (see SER Section 3.6.2.2.2)
High-voltage insulators composed of Porcelain; malleable iron; aluminum; galvanized steel; cement exposed to Air – outdoor (3.6.1-3)	Reduced insulation resistance caused by presence of salt deposits or surface contamination	A plant-specific aging management program is to be evaluated for plants located such that the potential exists for salt deposits or surface contamination (e.g., in the vicinity of salt water bodies or industrial pollution)	Yes	Not applicable	Not applicable to Callaway (see SER Section 3.6.2.2.2)
Transmission conductors composed of Aluminum; steel exposed to Air – outdoor (3.6.1-4)	Loss of conductor strength caused by corrosion	A plant-specific aging management program is to be evaluated for ACSR	Yes	Not applicable	Not applicable to Callaway (see SER Section 3.6.2.2.3)
Transmission connectors composed of Aluminum; steel exposed to Air – outdoor (3.6.1-5)	Increased resistance of connection caused by oxidation or loss of pre-load	A plant-specific aging management program is to be evaluated	Yes	Not applicable	Not applicable to Callaway (see SER Section 3.6.2.2.3)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Switchyard bus and connections composed of Aluminum; copper; bronze; stainless steel; galvanized steel exposed to Air – outdoor (3.6.1-6)	Loss of material caused by wind-induced abrasion; Increased resistance of connection caused by oxidation or loss of pre-load	A plant-specific aging management program is to be evaluated	Yes	Not applicable	Not applicable to Callaway (see SER Section 3.6.2.2.3)
Transmission conductors composed of Aluminum; Steel exposed to Air – outdoor (3.6.1-7)	Loss of material caused by wind-induced abrasion	A plant-specific aging management program is to be evaluated for ACAR and ACSR	Yes	Not applicable	Not applicable to Callaway (see SER Section 3.6.2.2.3)
Insulation material for electrical cables and connections (including terminal blocks, fuse holders, etc.) composed of Various organic polymers (e.g., EPR, SR, EPDM, XLPE) exposed to Adverse localized environment caused by heat, radiation, or moisture (3.6.1-8)	Reduced insulation resistance caused by thermal/ thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	Chapter XI.E1, “Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements”	No	Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Consistent with the GALL Report
Insulation material for electrical cables and connections used in instrumentation circuits that are sensitive to reduction in conductor insulation resistance (IR) composed of Various organic polymers (e.g., EPR, SR, EPDM, XLPE) exposed to Adverse localized environment caused by heat, radiation, or moisture (3.6.1-9)	Reduced insulation resistance caused by thermal/thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	Chapter XI.E2, “Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits”	No	Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Conductor insulation for inaccessible power cables greater than or equal to 400 volts (e.g., installed in conduit or direct buried) composed of Various organic polymers (e.g., EPR, SR, EPDM, XLPE) exposed to Adverse localized environment caused by significant moisture (3.6.1-10)	Reduced insulation resistance caused by moisture	Chapter XI.E3, "Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	No	Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Consistent with the GALL Report
Metal enclosed bus: enclosure assemblies composed of Elastomers exposed to Air – indoor, controlled or uncontrolled or Air – outdoor (3.6.1-11)	Surface cracking, crazing, scuffing, dimensional change (e.g., "ballooning" and "necking"), shrinkage, discoloration, hardening and loss of strength caused by elastomer degradation	Chapter XI.E4, "Metal Enclosed Bus," or Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Metal Enclosed Bus	Consistent with the GALL Report
Metal enclosed bus: bus/connections composed of Various metals used for electrical bus and connections exposed to Air – indoor, controlled or uncontrolled or Air – outdoor (3.6.1-12)	Increased resistance of connection caused by the loosening of bolts caused by thermal cycling and ohmic heating	Chapter XI.E4, "Metal Enclosed Bus"	No	Metal Enclosed Bus	Consistent with the GALL Report
Metal enclosed bus: insulation; insulators composed of Porcelain; xenoy; thermo-plastic organic polymers exposed to Air – indoor, controlled or uncontrolled or Air – outdoor (3.6.1-13)	Reduced insulation resistance caused by thermal/thermoxidative degradation of organics/thermoplastics, radiation-induced oxidation, moisture/debris intrusion, and ohmic heating	Chapter XI.E4, "Metal Enclosed Bus"	No	Metal Enclosed Bus	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Metal enclosed bus: external surface of enclosure assemblies composed of Steel exposed to Air – indoor, uncontrolled or Air – outdoor (3.6.1-14)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.E4, "Metal Enclosed Bus," or Chapter XI.S6, "Structures Monitoring"	No	Metal Enclosed Bus	Consistent with the GALL Report
Metal enclosed bus: external surface of enclosure assemblies composed of Galvanized steel; aluminum exposed to Air – outdoor (3.6.1-15)	Loss of material caused by pitting and crevice corrosion	Chapter XI.E4, "Metal Enclosed Bus," or Chapter XI.S6, "Structures Monitoring"	No	Metal Enclosed Bus	Consistent with the GALL Report
Fuse holders (not part of active equipment): metallic clamps composed of Various metals used for electrical connections exposed to Air – indoor, uncontrolled (3.6.1-16)	Increased resistance of connection caused by chemical contamination, corrosion, and oxidation (in an air, indoor controlled environment, increased resistance of connection caused by chemical contamination, corrosion and oxidation do not apply); fatigue caused by ohmic heating, thermal cycling, electrical transients	Chapter XI.E5, "Fuse Holders"	No	Not applicable	Not applicable to Callaway (see SER Section 3.6.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Fuse holders (not part of active equipment): metallic clamps composed of Various metals used for electrical connections exposed to Air – indoor, controlled or uncontrolled (3.6.1-17)	Increased resistance of connection caused by fatigue caused by frequent manipulation or vibration	Chapter XI.E5, "Fuse Holders" No aging management program is required for those applicants who can demonstrate these fuse holders are located in an environment that does not subject them to environmental aging mechanisms or fatigue caused by frequent manipulation or vibration	No	Not applicable	Not applicable tp Callaway (see SER Section 3.6.2.1.1)
Cable connections (metallic parts) composed of Various metals used for electrical contacts exposed to Air – indoor, controlled or uncontrolled or Air – outdoor (3.6.1-18)	Increased resistance of connection caused by thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation	Chapter XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	No	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Consistent with the GALL Report
Connector contacts for electrical connectors exposed to borated water leakage composed of Various metals used for electrical contacts exposed to Air with borated water leakage (3.6.1-19)	Increased resistance of connection caused by corrosion of connector contact surfaces caused by intrusion of borated water	Chapter XI.M10, "Boric Acid Corrosion"	No	Boric Acid Corrosion	Consistent with the GALL Report
Transmission conductors composed of Aluminum exposed to Air – outdoor (3.6.1-20)	Loss of conductor strength caused by corrosion	None - for Aluminum Conductor Aluminum Alloy Reinforced (ACAR)	None	Not applicable	Not applicable to Callaway (see SER Section 3.6.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Fuse holders (not part of active equipment): insulation material, Metal enclosed bus: external surface of enclosure assemblies composed of Insulation material: bakelite; phenolic melamine or ceramic; molded polycarbonate; other, Galvanized steel; aluminum, Steel exposed to Air – indoor, controlled or uncontrolled (3.6.1-21)	None	None	NA - No AEM or AMP	Not applicable	Not applicable to Callaway (see SER Section 3.6.2.1.1)

3.6.2.1 AMR Results Consistent with the GALL Report

LRA Section 3.6.2.1 identifies the materials, environments, and AERMs, and the following programs that manage aging effects for the electrical and I&C components:

- Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
- Boric Acid Corrosion
- Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
- Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
- Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
- Metal Enclosed Bus
- Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits That Are Sensitive to Reduction in Conductor Insulation Resistance

LRA Table 3.6.2-1 summarizes AMRs for the electrical and I&C components and indicates AMRs claimed to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report and for which it does not recommend further evaluation, the

staff's audit and 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 audited those AMRs with notes A–E, indicating how the AMR is consistent with the GALL Report.

Note A indicates that the AMR item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. The staff reviewed these items to confirm consistency with the GALL Report and validity of the AMR for the site-specific conditions.

Note B indicates that the AMR item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff reviewed these items to 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, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report; however, the applicant identified in the GALL Report a different component with the same material, environment, aging effect, and AMP as the component under review. The staff reviewed these items to 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, 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's evaluation follows.

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. The

staff noted that LRA Section 3.6.1 lists the following electrical component types subject to an AMR under "insulated cable and connections."

- electrical cables and connections not subject to 10 CFR 50.49 EQ requirements
- electrical cables and connections not subject to 10 CFR 50.49 EQ requirements used in instrumentation circuits that are sensitive to reduction in conductor insulation resistance
- inaccessible power cables not subject to 10 CFR 50.49 EQ requirements

However, LRA Section 3.6.2.1.4, "Insulated Cable and Connections," only lists the following AMPs:

- Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
- Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

By letter dated August 23, 2012, the staff issued RAI 3.6.2.1.4-1 to ask the applicant to explain why the Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits that are Sensitive to Reduction in Conductor Insulation Resistance AMP is not listed in LRA Section 3.6.2.1.4.

In its response dated September 20, 2012, the applicant stated that LRA Section 3.6.2.1.4 inadvertently omitted the Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits That Are Sensitive to Reduction in Conductor Insulation Resistance AMP. The applicant also amended the LRA to add LRA Section 3.6.2.1.4.3, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits That Are Sensitive to Reduction in Conductor Insulation Resistance" and credit the AMP.

The staff finds the applicant response acceptable because the applicant clarified that the omission of the AMP in LRA Section 3.6.2.1.4 was an error and the applicant also amended the LRA to credit the AMP under LRA Section 3.6.2.1.4. The staff finds the addition of LRA Section 3.6.2.1.4.3, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrumentation Circuits That Are Sensitive To Reduction In Conductor Insulation Resistance" is consistent with LRA Table 3.6-1, the GALL Report, and SRP-LR Table 3.6-1. The staff's concern related to RAI 3.6.2.1.4-1 is resolved.

3.6.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.6-1, items 3.6.1-20 and 3.6.1-21, the applicant claimed that the corresponding items in the GALL Report are not applicable because the component, material, and environment combination described in the SRP-LR does not exist for in-scope SCs at Callaway. The staff reviewed the LRA and FSAR and confirmed that the applicant's LRA does not have any AMR results applicable for these items.

For LRA Table 3.6-1 items discussed below, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable; however, the staff non-applicability verification of these items required the review of sources beyond the LRA and FSAR, and/or the issuance of RAIs.

In LRA Table 3.6-1, items 3.6.1-16 and 3.6.1-17, the applicant stated that for fuse holders (not part of a larger assembly): metallic clamps exposed to air – indoor controlled and uncontrolled, increased resistance of connection because of chemical contamination, corrosion, and oxidation; fatigue caused by ohmic heating, thermal cycling, electrical transients and frequent manipulation or vibration are not applicable to Callaway and no AMP is proposed. LRA Table 3.6.2-1 does not include fuse holder metallic clamps as a component type or identified fuse holder metallic clamps as generic note I (i.e., aging effect in the GALL Report for this component, material and environment combination is not applicable). The applicant stated, in Table 3.6-1, that no AMP is required because "[a]ll fuse holders including the fuses installed for electrical penetration protection are part of larger assemblies. GALL Report, item VI.A.LP-23 and VI.A.LP-31, "Fuse holders (not part of active equipment): metallic clamp," identifies the aging/effect mechanism as increased resistance of connection due to chemical contamination, corrosion, oxidation; fatigue due to ohmic heating, thermal cycling, electrical transients; and increased resistance of connection due to fatigue caused by frequent manipulation or vibration.

The associated GALL Report AMP XI.E5, "Fuse Holders," states that fuse holders within the scope of license renewal should be tested to provide an indication of the condition of the fuse holder metallic clamps. The GALL Report states that GALL Report AMP XI.E5 manages fuse holders (metallic clamps) located outside of active devices; however, fuse holders inside active devices are not within the scope of GALL Report AMP XI.E5. The applicant stated that GALL Report AMP XI.E5 is not applicable based on fuse holders (metallic clamps) being located in larger assemblies, which is inconsistent with GALL Report AMP XI.E5, "scope of program" program element. However, the staff noted that the applicant did not provide technical justifications as to why these in-scope fuse holders do not require aging management. By letter dated August 23, 2012, the staff issued RAI 3.6.2.1-1 requesting the applicant to provide an evaluation that addresses each aging effect or mechanism identified in GALL Report, items VI.A.LP-23 and VI.A.LP-31.

In its response dated September 20, 2012, and as supplemented by letter dated November 20, 2012, the applicant stated that GALL Report items VI.A.LP-23 and VI.A.LP-31, apply only to fuse holders and metallic clamps which are not part of active equipment. The applicant also stated that the GALL Report AMP XI.E5, "scope of program" program element, states that fuse holders inside an active device are not within the scope of GALL Report AMP XI.E5. The applicant further stated that LRA Table 3.6-1, items 3.6.1-16 and 3.6.1-17 have been revised to state that all fuse holders including fuse holders for electrical penetrations that use metallic clamps are within the scope of license renewal as part of an active device and do not require aging management.

The staff finds the applicant response acceptable because the applicant clarified that all in-scope fuse holders using metallic clamps do not require aging management because they are located in active equipment. Therefore, the staff finds the applicants claim that the corresponding GALL AMR items are not applicable acceptable. The staff's concern described in RAI 3.6.2.1-1 is resolved.

3.6.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation is Recommended

In LRA Section 3.6.2.2, the applicant further evaluated aging management, as recommended by the GALL Report, for the electrical and I&C components and provides information concerning how it will manage the following aging effects:

- electrical equipment subject to EQ
- reduced insulation resistance due to presence of any salt deposits and surface contamination, and loss of material due to mechanical wear caused by wind blowing on transmission conductors
- loss of material due to wind-induced abrasion, loss of conductor strength due to corrosion, and increased resistance of connection due to oxidation or loss of pre-load
- QA for aging management of nonsafety-related components

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 it adequately addressed the issues further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.2.2.2. The staff's review of the applicant's further evaluation follows.

3.6.2.2.1 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. The applicant stated that environmental qualification is a TLAA. Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(c)(1). The applicant also stated that the EQ of Electric Components Program meets the requirements of 10 CFR 50.49. The applicant further stated that evaluation of this TLAA is addressed separately in LRA Section 4.4. The staff's review of the applicant's evaluation of this TLAA and the EQ of Electrical Components Program is documented in SER Sections 4.4 and 3.0.3.1.19, respectively. The applicant's program also includes environmental qualification of mechanical components qualified in accordance with Criterion 4, "Environmental and Dynamic Effects Design Basis" of Appendix A to 10 CFR Part 50. LRA Section 4.7.10 addresses the TLAA for mechanical EQ equipment. The staff's evaluation of the TLAA for mechanical EQ equipment is documented in SER Section 4.7.10.

3.6.2.2.2 Reduced Insulation Resistance Due to Presence of Any Salt Deposits and Surface Contamination, and Loss of Material Due to Mechanical Wear Caused by Wind Blowing on Transmission Conductors

LRA Section 3.6.2.2.2, associated with LRA Table 3.6-1, items 3.6.1-2 and 3.6.1-3, addresses reduced insulation resistance due to presence of salt deposits and surface contamination, and loss of material caused by mechanical wear. The applicant stated that Callaway is located in an area with moderate rain fall and is not subject to air pollution or salt spray. The applicant also stated that contamination of high-voltage insulators is not a problem because of sufficient rainfall periodically washing the high-voltage insulators. The applicant noted that Callaway has no operating experience indicating instances of flashover because of pollution or salt deposits. The applicant therefore concluded that degradation of insulator quality in the absence of salt deposits and surface contamination is not an aging effect requiring aging management.

The applicant stated that industry experience has shown that transmission conductors are designed and installed not to swing significantly and cause wear because of wind-induced abrasion and fatigue. The applicant also stated that Callaway transmission conductors are designed and installed not to swing significantly. The applicant noted that Callaway has no operating experience indicating loss of material on high-voltage connectors because of mechanical wear from wind-induced abrasion or fatigue. The applicant further stated that

therefore, loss of material caused by wind-induced abrasion and fatigue is not an applicable aging effect requiring management.

The staff reviewed LRA Section 3.6.2.2.2 against the criteria in SRP-LR Section 3.6.2.2.2, which states that reduced insulation resistance caused by salt deposits and 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 caused by 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 SRP-LR Section 3.6.2.2.2 states that further evaluation of a plant specific AMP is recommended for management of reduced insulation resistance caused by presence of salt deposits and surface contamination for plants located such that potential exists for salt deposits or surface contamination (e.g., in the vicinity of salt water bodies or industrial pollution).

The staff finds that Callaway is not located in vicinity of either salt water bodies or industrial pollution; therefore, surface contamination of high-voltage insulator is not a concern. In addition, rainfall and snow periodically wash away contamination and the glazed insulator surface also aids with this contamination removal. The staff also finds that the plant-specific operating experience at Callaway supports the applicant's conclusion that contamination is not significant because there has been no occurrence of insulator flashover caused by salt or pollution surface contamination or experience with loss of material because of mechanical wear from wind-induced movement of transmission conductors.

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. 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 are designed not to normally swing but when they do, (e.g., because of a substantial wind), transmission conductors do not continue to swing for a long period of time once the wind has subsided. The applicant has not identified loss of material on high-voltage insulators caused by mechanical wear based on plant specific operating experience. Based on its review, the staff finds the mechanical wear aging effect of high-voltage insulators is not an aging effect requiring management at Callaway.

Based on the programs identified above, the staff concludes that the applicant has met the SRP-LR Section 3.6.2.2.2 criteria. For those items associated with LRA Section 3.6.2.2.2, 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 function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.2.3 Loss of Material Due to Wind-Induced Abrasion, Loss of Conductor Strength Due to Corrosion, and Increased Resistance of Connection due to Oxidation or Loss of Pre-Load

LRA Section 3.6.2.2.3, associated with LRA Table 3.6-1, items 3.6.1-4, 5, 6, and 7 address loss of material due to wind-induced abrasion and fatigue, loss of conductor strength because of

corrosion, and increased resistance of connections caused by oxidation or loss of pre-load of transmission conductors and connections, and switchyard bus and connections.

The applicant stated that industry experience has shown that transmission conductors are designed and installed not to sway significantly and cause wear due to wind-induced abrasion and fatigue. The applicant stated that loss of material due to wind-induced abrasion is not an applicable aging effect requiring management for the period of extended operation. The applicant did not include plant specific operating experience for Callaway to support the applicant's claim that wind-induced abrasion and fatigue is not a significant aging effect for transmission conductors. The applicant did not address whether a review of plant specific operating experience indicated additional aging effects exist beyond those addressed in the GALL Report. By letter dated August 23, 2012, the staff issued RAI 3.6.2.2.3-1 requesting the applicant confirm that there has been no plant-specific occurrence of transmission conductor wind-induced abrasion and fatigue, and if they have occurred, the staff requested the applicant to describe the corrective actions performed to prevent reoccurrence.

In its response dated September 20, 2012, the applicant stated that based on a review of Callaway corrective action documents there has been no plant-specific operating experience of loss of material due to wind-induced abrasion or fatigue, loss of conductor strength due to corrosion, or increased resistance of connection due to oxidation or loss of preload in transmission conductors and connections, or in switchyard bus and connections. The applicant also stated that there are no additional aging effects beyond those identified by the GALL Report and SRP-LR Section 3.6.2.2.3.

The staff finds the applicant response acceptable because the applicant has provided plant-specific operating experience to further justify its claim that 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 are not significant aging effects for transmission conductors and connections consistent with SRP-LR Section 3.6.2.2.3 and Appendix A.1, including plant-specific operating experience. The staff's concern described in RAI 3.6.2.2.3-1 is resolved.

The applicant stated that the most prevalent aging mechanism contributing to the loss of transmission conductor strength is corrosion. The applicant also stated that corrosion rates depend largely on air quality (e.g., air particulates), SO_2 concentration, rain, fog chemistry, and other weather conditions. The applicant further stated that Callaway is not subject to industrial or salt pollution. The applicant noted that Callaway FSAR Section 2.3.1.2.10-SA shows that there is a low frequency and duration (22 days in 5 years) of high air pollution potential caused by low mixing depth and low wind speed at Callaway.

The applicant stated that transmission conductors within the switchyard are 91 strand 2,500-kilo-circular-mils (kcmil) stranded aluminum conductors (SAC) to the first tower leaving the switchyard. The applicant also stated that SAC corrosion is not a credible aging effect that requires management for the period of extended operation. Transmission conductors from the switchyard tower to startup transformer XMRO1 are 795 kcmil aluminum conductors, steel reinforced (ACSR). The applicant also stated that Callaway ACSR conductors have adequate design margin to offset the loss of strength because of corrosion and will continue to meet National Electrical Safety Code (NESC) requirements of not exceeding 60 percent of the rated breaking strength for the period of extended operation.

The applicant referenced a study performed by Ontario Hydroelectric. The report was issued in two parts; part one of the report described field and laboratory tests to determine the condition

of ACSR conductors while part 2 of the report analyzed the test results to determine the useful life of ACSR conductors. Ontario Hydroelectric undertook the study based on realization that one-third of Ontario Hydroelectric's transmission lines would soon exceed their stated design life. The report indicated that the consequences of transmission lines exceeding their design life are decreased reliability seen as a reduction in system operability and maintainability, supply reliability, and public safety.

The Ontario Hydroelectric study presented three life estimation techniques; the first was based on zinc losses using a corrosion detector developed for the study and assumed a constant degradation rate. The report considered this test qualitative based on variations in zinc thickness and uncertainty as to the thickness of the original zinc coating and was not effective if the zinc coating is pierced or removed.

The second method estimated life based on torsion ductility based on the number of turns to failure. This test method was applied to overhead ground wires, its application to ACSR conductors was considered conservative by the report since the steel core of ACSR cable does not carry the full load of the conductors.

The third test employed in the study was a tensile test of ACSR conductors. This tensile test along with the torsional ductility test provided the most precise information. In all cases the average value for the tests was greater than 60 years with the tensile test indicating an average greater than 80 years for ASCR conductors.

The tests performed by Ontario Hydroelectric found that the steel wire components showed reductions in tensile strength and that the reduction in conductor strength was primarily with the steel wire. The aluminum conductors were found to be in good condition. The Ontario Hydroelectric study also noted that environmental factors affected the corrosion of transmission line conductors. The study developed averages based on areas with industrial pollution and commercial development to regions with largely underdeveloped land. The regional averages for tensile tests were all greater than 70 years with regions containing little industry greater than 80 years. The report also indicated that the aggregate breaking strength was found to be 30 percent below the rated breaking strength for an 80-year-old ACSR cable because of corrosion.

The ACSR transmission conductors tested in the Ontario Hydroelectric report are documented in paper, "Aged ACSR Conductors, Part I – Testing Procedures for Conductors and Line Items" and "Aged ACSR Conductors Part 2 – Prediction of Remaining Life." The applicant stated that ACSR conductor construction was included in the Ontario Hydroelectric test, and therefore the results of Ontario Hydroelectric test are representative of the ACSR transmission conductors installed at Callaway.

The applicant referenced the NESC which requires that tension on installed conductors be less than 60 percent of the rated breaking strength. The applicant stated that the NESC also sets the maximum tension a conductor must be designed to withstand under heavy load requirements, which includes consideration of ice, wind, and temperature. The applicant also stated that the ACSR transmission conductors with seven steel strands have a rated breaking strength of 22,100 lbs. The applicant further stated that the ACSR transmission conductors within the scope of license renewal are installed so that conductor final tension is 4,337 lbs at 60 °F and does not exceed the NESC heavy loading condition of 5,525 lbs.

The Ontario Hydroelectric Study found that 80-year-old ACSR transmission conductors with a seven strand core had a breaking strength 30 percent below the rated breaking strength. The

applicant stated that, assuming a 30 percent loss of rated breaking strength of 6,630 lbs because of corrosion over 60 years, the in-scope ACSR transmission conductors installed at Callaway have adequate design margin to offset the loss of strength because of corrosion. The applicant also stated that the ACSR transmission conductors will still meet the NESC requirement of not exceeding 60 percent of the rated breaking strength ((22,100–6,630) x 60 percent = 9,282 lbs). The applicant further stated that the Ontario Hydroelectric test envelopes the conductors at Callaway and based on margin, demonstrates that material loss on the Callaway transmission conductors is acceptable for the period of extended operation. Based on the above, the applicant concluded that corrosion is not a credible aging effect that requires management for the period of extended operation.

The applicant stated that the outdoor environment is not subject to industry air pollution or saline environment. The applicant also stated that aluminum bus material, galvanized steel support structures and aluminum connection material do not experience appreciable aging effects in this environment. The applicant further stated that Callaway includes stainless steel Belleville washers in connection configurations that are torqued to prevent loss of preload. Finally the applicant stated that these connections are periodically evaluated via thermography as part of preventive maintenance activities. The applicant concluded that increased resistance of connections because of oxidation or loss of preload are not AERM for the period of extended operation.

The staff noted that the applicant did not include plant-specific operating experience at Callaway to support the its claim that loss of ACSR conductor strength caused by corrosion, or increased resistance of connection because of oxidation or loss of preload are not significant aging effects requiring aging management, In addition, the applicant did not address whether a review of plant-specific operating experience indicated additional aging effects exist beyond those addressed in the GALL Report. By letter dated August 23, 2012, the staff issued RAI 3.6.2.2.3-1 requesting the applicant confirm that there has been no plant-specific operating experience of loss of conductor strength caused by corrosion, or increased resistance of connection caused by oxidation or loss of preload.

In its response dated September 20, 2012, the applicant stated that based on a review of Callaway corrective action documents there has been no plant-specific operating experience of loss of material caused by wind-induced abrasion or fatigue, loss of conductor strength because of corrosion, or increased resistance of connection caused by oxidation or loss of preload in transmission conductors and connections, or in switchyard bus and connections. The applicant also stated that there are no additional aging effects beyond those identified by the GALL Report and SRP-LR Section 3.6.2.2.3.

The staff finds the applicant response acceptable because the applicant has provided plant-specific operating experience to further justify its claim that loss of material due to wind-induced abrasion and fatigue, loss of transmission conductor strength from corrosion, increased resistance of connection because of oxidation or loss of preload are not significant aging effects for transmission conductors and connections consistent with the GALL Report, SRP-LR Section 3.6.2.2.3 and SRP-LR Appendix A.1, including plant specific operating experience. The staff's concern described in RAI 3.6.2.2.3-1 is resolved.

The staff reviewed LRA Section 3.6.2.2.3 against the criteria in SRP-LR Section 3.6.2.2.3, which states that loss of material due to wind-induced abrasion and fatigue, loss of conductor strength because of corrosion, and increased resistance of connection caused by 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 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 is not an applicable aging mechanism for switchyard bus and connections at Callaway.

The staff noted that wind born particulates have not been shown to be a contributor to loss of material at Callaway. Therefore, the staff finds that wind-induced abrasion and fatigue is not a significant aging effect requiring management for transmission conductors and connections at Callaway.

The staff noted that design of switchyard bolted connections precludes torque relaxation. The use of stainless steel Belleville washers is the industry standard to preclude torque relaxation. Callaway design incorporates the use of stainless steel Belleville washers on bolted electrical connections to compensate for temperature changes, maintain the proper torque, and prevent loss of preload. This method of assembly is consistent with the good bolting practices recommended by EPRI TR-104213, "Bolted Joint Maintenance & Application Guide." The applicant's preventive maintenance activities include periodically inspecting the connections through the use of thermography. The staff finds that increased resistance of connection caused by oxidation or loss of pre-load are not significant AERM for transmission conductor and switchyard bus connections at Callaway.

The Ontario Hydroelectric study showed a 30 percent loss of conductor strength of an 80-year-old ACSR conductor due to corrosion. In addition, the NESC requires that tension on installed conductors be a maximum of 60 percent of the rated conductor breaking strength. The NESC also sets the maximum tension a conductor must be designed to withstand under heavy load requirements, which include consideration of ½ inch of radial ice and 4 pounds per square feet wind. Based on Callaway data the ACSR transmission conductors have a rated breaking strength of 22,100 lbs and calculated heavy load tension of 5,525 lbs with an actual installed tension of 4,337 lbs. For a new conductor, NESC criteria would allow an installed tension of 13,260 lbs (22100 x 0.6) which results in a margin of 8,840 lbs (40 percent margin). The actual installed margin for Callaway is 17,763 lbs (22,100 lbs – 4,337) or 80 percent. Based on the Ontario Hydroelectric study, a loss of conductor strength of 30 percent on ACSR conductors would mean that the 60-year conductor strength for Callaway would be 15,470 lbs. (22,100 lbs x 0.7) lbs). The NESC-installed tension for a 60-year conductor at Callaway would be 9,282 lbs (15,470 x 0.6) resulting in an installed margin of 6,188 lbs (15,470 lbs – 9,282 lbs). The margin between the NESC calculated heavy load and the calculated Callaway transmission conductor 60-year breaking strength is 9,945 lbs (15,470 lbs – 5,525). The actual margin between the conductor installed tension and Callaway transmission conductor 60-year breaking strength is 11,133 lbs (15,470 lbs – 4,337 lbs) resulting in a 72 percent margin to the 60-year transmission conductor breaking strength. The ratio between the NESC calculated heavy load tension and the 60-year conductor breaking strength would be approximately 35 percent (5,525 lbs/15,470 lbs). The NESC requires that tension on installed conductor be a maximum of 60 percent of the ultimate conductor strength. The staff determined that the example provided by the applicant bounds the in-scope Callaway transmission conductors. With a 30 percent loss of conductor strength, there remains ample margin between the NESC requirements and the actual conductor strength.

The applicant also stated that corrosion of SAC transmission conductors within the switchyard to the first tower leaving the switchyard is not a credible aging effect that requires management for the period of extended operation. This is consistent with item VI.A LP-46 of the GALL Report and therefore the staff finds that loss of conductor strength due to corrosion for SAC transmission conductors is not a significant aging effect at Callaway. In addition, the staff finds that loss of conductor strength due to corrosion is not a significant aging effect requiring management for ACSR transmission conductors at Callaway.

Based on the programs identified above, the staff concludes that the applicant has met the SRP-LR Section 3.6.2.2.3 criteria. For those items associated with LRA Section 3.6.2.2.3, 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 function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA Program.

3.6.2.2.5 Operating Experience

SER Section 3.0.5, "Operating Experience for Aging Management Programs," documents the staff's evaluation of the applicant's consideration of operating experience of aging management programs.

3.6.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

In LRA Table 3.6.2-1, the staff reviewed additional details of the AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Table 3.6.2-1, the applicant indicated, via notes F through J, that the combination of component type, material, environment, and AERM does not correspond to an AMR 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 AMR item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the AMR item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

3.6.2.3.1 Electrical and Instrumentation and Controls—Summary of Aging Management Evaluation—Electrical Components—LRA Table 3.6.2-1

The staff reviewed LRA Table 3.6.2-1, which summarizes the results of AMR evaluations for the electrical components component groups.

Carbon Steel (Galvanized), Cement (Electrical Insulators), and Porcelain High Voltage Insulators Exposed to Atmosphere or Weather (External). In LRA Table 3.6.2-1, the applicant stated that for high voltage insulators made of carbon steel (galvanized), cement (electrical insulators), and porcelain, and exposed to atmosphere or weather (external), there are no aging effects and no AMPs are proposed. The AMR items cite generic note I and are associated with LRA Table 3.6-1, items 3.6.1-2 and 3.6.1-3. The AMR items also cite plant specific note 1, which state that the discussion of these items is documented in LRA Section 3.6.2.2.2. The staff's evaluation of LRA Section 3.6.2.2.2 and items 3.6.1-2 and 3.6.1-3 is documented in SER Sections 3.6.2.2.2.

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

Aluminum, Carbon Steel (Galvanized), and Stainless Steel Switchyard Bus and Connections Exposed to Atmosphere or Weather (External). In LRA Table 3.6.2-1, the applicant stated that for switchyard bus and connections made of aluminum, carbon steel (galvanized), and stainless steel, and exposed to atmosphere or weather (external), there are no aging effects and no AMPs are proposed. The AMR items cite generic note I and are associated with LRA Table 3.6-1, item 3.6.1-6. The AMR items also cite plant specific note 2, which state that the discussion of these items is documented in LRA Section 3.6.2.2.3. The staff's evaluation of LRA Section 3.6.2.2.3 and item 3.6.1-6 is documented in SER Section 3.6.2.2.3.

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

Aluminum, Aluminum Conductor Steel Reinforced, and Stainless Steel Transmission Conductors and Connections Exposed to Atmosphere or Weather (External). In LRA Table 3.6.2-1, the applicant stated that for transmission conductors and connections made of aluminum, aluminum conductor steel reinforced, and exposed to atmosphere or weather external there are no aging effects and no AMPs are proposed. The AMR items cite generic note I and are associated with LRA Table 3.6-1, items 3.6.1-2, 4, 5, and 7. The AMR items also cite plant specific note 2, which state that the discussion of these items is documented in LRA Section 3.6.2.2.3. The staff's evaluation of LRA Section 3.6.2.2.3 and items 3.6.1-4, 5, and 7, is documented in SER Section 3.6.2.2.3. The staff's evaluation of item 3.6.1-2 is documented in SER Section 3.6.2.2.2.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be

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

3.6.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the electrical and I&C components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.7 Conclusion for Aging Management Review Results

The staff reviewed the information in LRA Section 3, “Aging Management Review,” and LRA Appendix B, “Aging Management Programs.” On the basis of its review of the AMR results and AMPs, the staff concludes that the applicant has demonstrated that the aging effects will be adequately managed so that the intended 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 applicable FSAR supplement program summaries and concludes that the FSAR supplement adequately describes the AMPs credited for managing aging, as required by 10 CFR 54.21(d).

With regard to these matters, the staff concludes that there is reasonable assurance that the applicant will continue to conduct the activities authorized by the renewed license in accordance with the CLB, and any changes made to the CLB, in order to comply with 10 CFR 54.21(a)(3), are in accordance with the Atomic Energy Act of 1954, as amended, 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 evaluation performed by the United States (U.S.) Nuclear Regulatory Commission (NRC) staff (the staff) of the basis provided by Union Electric Company (doing business as Ameren Missouri) (the applicant) 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 SER section also provides the staff's evaluation of the applicant's basis for identifying those exemptions that need to be identified in the LRA.

In accordance with 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, "Definitions." Regulations in 10 CFR 54.3 state that a plant-specific or generic evaluation, analysis, or calculation is a TLAA if it meets all six of the following identification criteria:

(1) involves a system, structure, or component (SSC) 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 SSCs 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, "Specific Exemptions," and that are based on a TLAA. For any such exemptions, the applicant must evaluate and justify the continuation of the exemptions for the period of extended operation.

NUREG-1800, Revision 2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR), Section 4.1, "Identification of Time-Limited Aging Analyses," dated December 2010, provides the staff's guidance for reviewing LRA Section 4.1. 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 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 4.1.1 states that a list of potential TLAAs was assembled from regulatory guidance and industry experience, which included the SRP-LR; NUREG-1801, Revision 2, "Generic Aging Lessons Learned (GALL) Report," December 2010 (the GALL Report); Nuclear Energy Institute 95-10, Revision 6, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – the License Renewal Rule," June 2005 (NEI 95-10); 10 CFR 54; prior license renewal applications and plant-specific document reviews; and interviews with plant personnel.

The LRA also states that the applicant performed keyword searches for its CLB to determine whether each of these potential TLAAs exists in the licensing basis. This keyword search was also used to identify additional potential plant-specific TLAAs. This search of the CLB included the final safety analysis report (FSAR) – Standard Plant (SP), the FSAR – Site Addendum (SA), technical specifications and bases, SERs for the original operating license, subsequent SERs, and Ameren Missouri and the staff docketed licensing correspondences.

Next, the applicant stated that the list of potential TLAAs was reviewed with respect to the criteria for a TLAA specified in 10 CFR 54.3(a). This review was based on the information in the CLB source documents and from source documents for the potential TLAAs, such as vendor, staff-sponsored, and licensee topical reports, design calculations, code stress reports or code design reports, drawings, and specifications. The LRA states that these source documents provided the information and the basis for the dispositions in LRA Section 4.

Based on this review, LRA Table 4.1-1, "List of TLAAs," provides a list of the TLAAs applicable for the Callaway Plant:

- Neutron Embrittlement of the Reactor Vessel (LRA Section 4.2)
- Metal Fatigue of Vessels, Piping, and Components (LRA Section 4.3)
- Environmental Qualification (EQ) of Electric Equipment (LRA Section 4.4)
- Loss of Prestress in Concrete Containment Tendons (LRA Section 4.5)
- Fatigue of the Containment Liner and Penetrations (LRA Section 4.6)
- Other Plant-Specific TLAAs (LRA Section 4.7)

4.1.1.2 Identification of Exemptions

The LRA states that docketed correspondence, the operating license, and the FSAR were searched to identify exemptions in effect. Furthermore, there are only two exemptions "currently in effect," that are based in part on a TLAA. These two analyses are the use of the leak-before-break (LBB) evaluation of reactor coolant system piping and the use of American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Case N-514. The LRA states that the LBB analysis is described in LRA Section 4.7.7 and the use of ASME Code Case N-514, which supports the implementation of the low-temperature overpressure protection (LTOP) limits, is described in LRA Section 4.2.5.

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 reviewed for applicability to the Callaway 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 that Conform to the Definition of a TLAA, as defined in 10 CFR 54.3

The staff confirmed that the applicant included those TLAAs that SRP-LR Table 4.1-2 identifies as potentially being generically applicable to license renewal applicants. These TLAAs applicable to the applicant are provided below:

- Neutron Embrittlement of the Reactor Vessel (LRA Section 4.2)
- Metal Fatigue of Vessels, Piping, and Components (LRA Section 4.3)
- EQ of Electric Equipment (LRA Section 4.4)
- Loss of Prestress in Concrete Containment Tendons (LRA Section 4.5)
- Fatigue of the Containment Liner and Penetrations (LRA Section 4.6)

The staff determined that the applicant's identification of these TLAAs is consistent with the staff recommendations for identifying applicable TLAAs in SRP-LR Sections 4.2 and 4.6. Based on this review, the staff finds that the identification of these TLAAs is acceptable and is in accordance with 10 CFR 54.21(c)(1). The staff's evaluation of the applicant's dispositions for these TLAAs in accordance with 10 CFR 54.21(c)(1)(i), (ii), or (iii) is documented in the corresponding SER Sections 4.2, 4.3, 4.4, 4.5, and 4.6 and their subsections.

The staff confirmed that the applicant reviewed the list of potential plant-specific TLAAs identified in SRP-LR Table 4.1-3 and, of these, identified the potential plant-specific TLAAs that the applicant either included as plant-specific TLAAs in LRA Section 4 or justified that they were not applicable TLAAs in LRA Section 4, as amended by letter dated May 3, 2012. Those potential plant-specific TLAAs identified in SRP-LR Table 4.1-3 that the applicant determined were not applicable to its LRA are evaluated in SER Section 4.1.2.1.2.

In addition, LRA Section 4.7 contains those plant-specific TLAAs that were identified as part of the applicant's review of its CLB that are not correlated to SRP-LR Table 4.1-3. The staff's evaluation of the applicant's dispositions for these TLAAs, in accordance with 10 CFR 54.21(c)(1)(i), (ii), or (iii), is documented in the corresponding SER Section 4.7 and its subsections.

4.1.2.1.2 Evaluation of Applicant's List of Evaluations, Analyses, and Calculations that Do Not Conform to the Definition of a TLAA, as defined in 10 CFR 54.3

Absence of a TLAA for Reactor Vessel Underclad Cracking Analyses. LRA Table 4.1-1 identifies that the applicant's CLB does not include an analysis for reactor vessel underclad cracking that meets the definition of a TLAA. LRA Section 4.7.4 contains additional information related to the applicant's determination that there is no TLAA for reactor vessel underclad cracking.

By letter dated May 3, 2012, the applicant revised LRA Table 4.1-1 and LRA Section 4.7.4 to identify that its CLB contains a TLAA for reactor vessel underclad cracking. Specifically, the revised LRA Section 4.7.4 states that Westinghouse Commercial Atomic Power (WCAP)-15338-A has demonstrated that the vessel integrity is maintained in the presence of underclad cracks and addresses the aging mechanism of underclad cracking. WCAP-15338-A is, therefore, a TLAA for the Callaway Plant and is dispositioned in accordance with 10 CFR 54.21(c)(1)(i). The staff's evaluation of LRA Section 4.7.4, as amended by letter dated May 3, 2012, is documented in SER Section 4.7.4.2.

Absence of a TLAA for Inservice Local Metal Containment Corrosion Analyses. LRA Table 4.1-2 identifies that an inservice local metal containment corrosion analysis is applicable to its CLB and is evaluated in LRA Section 4.7.3, "Corrosion Analysis of the Reactor Vessel Cladding Indications." By letter dated May 3, 2012, the applicant revised LRA Table 4.1-2 to indicate that the CLB does not include any inservice local metal containment corrosion analyses for its plant.

The staff reviewed FSAR Section 3.8 and noted that the containment structure is designed to house the reactor coolant system (RCS) and is referred to as the reactor building. The reactor building is part of the containment system designed to control the release of airborne radioactivity following postulated design basis accidents and to provide shielding for the reactor core and the RCS. FSAR Section 3.8.1.1.1 further describes the reactor building as consisting of a prestressed, reinforced concrete, cylindrical structure with a hemispherical dome and a conventionally reinforced concrete base slab with a central cavity and instrumentation tunnel to house the reactor vessel.

The staff confirmed that FSAR Section 3.8 does not reference any localized metal corrosion analyses for the containment structure, other Seismic Category 1 structures, or their subcomponents. Therefore, the staff finds that the LRA does not need to include any localized metal containment corrosion TLAAs because the applicant's CLB does not include or reference metal corrosion analyses for the concrete containment structure, other Seismic Category 1 structures, or their subcomponents.

Absence of a TLAA for Intergranular Separations in the Heat-Affected Zone (HAZ) of Reactor Vessel Low-Alloy Steel under Austenitic SS Cladding. LRA Table 4.1-2 identifies that the Westinghouse technical report analysis of intergranular separations in the heat-affected zones of the reactor vessel low-alloy steel forging to cladding welds is not applicable to its CLB and is evaluated in LRA Section 4.7.4. By letter dated May 3, 2012, the applicant revised LRA Table 4.1-2 to indicate that this analysis is applicable to its CLB and is a TLAA, which is evaluated in LRA Section 4.7.4. The staff's evaluation of LRA Section 4.7.4, as amended by letter dated May 3, 2012, is documented in SER Section 4.7.4.2.

Absence of a TLAA for Flow-Induced Vibration Endurance Limit for the Reactor Vessel Internals. LRA Table 4.1-2 identifies that an analysis for flow-induced vibration endurance limit for the reactor vessel internal (RVI) components is not applicable to its CLB and that the basis for claiming an absence of a TLAA on this topic is evaluated in LRA Section 4.3.3. LRA Section 4.3.3 states that protection from flow-induced vibration for the RVI components is ensured by satisfying the regulatory position in Regulatory Guide (RG) 1.20, "Comprehensive Vibration Assessment Program for Reactor Internals during Preoperational and Initial Startup Testing." The applicant also stated that the basis for meeting RG 1.20 is discussed in FSAR Sections 3.9(N).2.3, 3.9(N).2.4, and 3.9(N).2.6 SP. The applicant stated that its review of the

supporting references in these FSAR sections did not identify any analyses that were based on time-limited assumptions defined by the current operating term.

The staff noted that RG 1.20 provides an acceptable position that can be used by an applicant to demonstrate compliance with the technical information requirements for flow-induced vibrations in 10 CFR 50.34, "Design Objectives for Equipment to Control Releases of Radioactive Material in Effluents — Nuclear Power Reactors." It also permits applicants to assess flow-induced vibrations of their RVI components using prototypical data and tests results from other U.S. pressurized-water reactors (PWRs) whose RVI components were well analyzed for their responses to flow-induced vibrations. The staff reviewed FSAR Sections 3.9(N).2.3, 3.9(N).2.4, and 3.9(N).2.6 SP and confirmed that there is no discussion or reference to analyses associated with a dependence on time for flow-induced vibration endurance limits for the RVIs. Based on its review of the FSAR, the staff determined that the evaluation of high cycle vibrational loads does not depend on the licensed period and is therefore not a TLAA in accordance with 10 CFR 54.3(a).

Absence of a Fatigue Analysis TLAA for the Metal Containment Liner. LRA Section 4.6 states that the applicant's review of the CLB did not identify any fatigue analyses for the containment liner plate. Furthermore, the LRA states that the prestressed concrete containment vessel was poured against a steel membrane liner designed to the standards in Bechtel Topical Report BC-TOP-1, Revision 1, "Containment Building Liner Plate Design Report," (BC-TOP-1). The applicant clarified that the containment liner and other metal containment components were designed to stress limit criteria of BC-TOP-1, independent of the number of load cycles, and require no fatigue analyses with the exception of the main steam and feedwater penetrations, the containment access hatches, and the leak chases.

The staff reviewed FSAR-SP Section 3.8.1.4.6, "Steel Liner Plate and Anchors," which identifies the governing design documents for the containment liner plate to be Bechtel Report BC-TOP-1, and BC-TOP-5-A Sections 6.8, 7.5, and Appendix C. The staff searched the design calculations (BC-TOP-1) in the CLB for the liner and noted that, for design calculations, it "was subjected to the effects of prestress, concrete creep and shrinkage, deadload, maximum hypothetical earthquake, accident thermal gradients, and accident pressure." BC-TOP-1 does not contain an entry for fatigue or loading cycles related to fatigue design of the liner plate. The staff also reviewed BC-TOP-5-A Sections 6.8, "Liner Plate System," 7.5, "Liner Plate System," and Appendix C, "Design Criteria," and noted the only relevant entry regarding fatigue is in Appendix C of BC-TOP-5-A, which incorporates verbatim Section CC-3760, "Fatigue," of the Proposed Standard for Concrete Reactor Vessels and Containments (Proposed Section III, Division 2) ASME B&PV Code.

The staff searched both the FSAR-SP and FSAR-SA using the keywords "cycles" and "fatigue." There were no entries related to loading cycles for the steel liner, but there were entries related to fatigue. Key elements of Section CC-3760, "Fatigue," are replicated in FSAR-SP Section 3.7(B).3.2, "Determination of Number of Earthquake Cycles," which states that "[f]atigue was not considered in the design of seismic Category I structures, because the occurrence of full design earthquake loads is too infrequent to warrant consideration of fatigue design, and the calculated stresses and strains are below yield." FSAR-SP Table 3.8-3, "Stress Limits for Steel Portions of Concrete Containments Designed in Accordance with Subsection NE of the ASME Code," contains three loading combinations that consider fatigue in the analysis when peak stresses are involved. These, however, are considered for Section 3.8.2, "Containment System Steel Items," which describes the major penetrations and portions of penetrations intended to resist pressure, which are not backed by structural concrete. The fatigue analyses for the main

steam and feedwater penetrations are discussed in LRA Section 4.6.1, the fatigue analyses for the containment access hatches and the leak chases are discussed in LRA Section 4.6.2, and the staff's reviews of these LRA sections are documented in SER Sections 4.6.1 and 4.6.2, respectively.

Based on its review, the staff confirmed that the analysis and design procedures used for the liner plate system are in accordance with BC-TOP-1. Furthermore, FSAR Table 1.6-1 indicates that BC-TOP-1 was submitted to the staff for review in January 1973 and was later approved by the staff. The staff reviewed BC-TOP-1 and confirmed that it does not include an analysis that is dependent on time-limited assumptions defined by the current operating term for the metal containment liner; thus, the staff finds the design of containment liner plate does not include a TLAA.

Absence of a TLAA for Ductility Reduction of Fracture Toughness for the Reactor Vessel Internals. LRA Section 4.3.3 states that a review of the CLB did not identify a 40-year ductility reduction analysis for RVI components.

The staff noted that SRP-LR Section 3.1.2.2.3.3 states that the evaluation of ductility reduction may be a plant-specific TLAA for the RVI components in Babcock and Wilcox (B&W) reactor designs and is to be evaluated for the period of extended operation in accordance with the staff's safety evaluation on B&W Owners Group Technical Report No. BAW-2248, "Demonstration of the Management of Aging Effects for the Reactor Vessel Internals," dated December 9, 1999, (Agencywide Documents Access and Management System (ADAMS) Accession No. ML993490303). The staff reviewed the FSAR and confirmed that the applicant's CLB does not contain or reference a 40-year embrittlement analysis for RVI components. In addition, the staff determined that Technical Report No. BAW-2248 is not applicable because the applicant's plant is a Westinghouse-designed PWR. Instead, the staff confirmed that the applicant manages loss of fracture toughness and reduced material ductility in the RVI components during the period of extended operation with its PWR Vessel Internal Program. The staff's evaluation of the PWR Vessel Internal Program is documented in SER Section 3.0.3.1.5. Based on its review of the FSAR, the staff determined that an analysis of ductility reduction for RVI components does not exist in the applicant's CLB and, therefore, is not a TLAA in accordance with 10 CFR 54.3(a).

Absence of a TLAA for Metal Corrosion Allowance. LRA Table 4.1-2 identifies that metal corrosion allowance analyses are not applicable to the applicant's CLB because no explicit metal corrosion allowance analysis basis that is based on plant life applies to the CLB. By letter dated May 3, 2012, the applicant revised LRA Table 4.1-2 to indicate that the CLB does include a metal corrosion analysis that is TLAA for the LRA. The applicant stated that the TLAA is evaluated in LRA Section 4.7.3, as amended for in the letter of May 3, 2012.

The staff's evaluation of the revised LRA Section 4.7.3 is documented in SER Section 4.7.3.2.

Absence of a TLAA for Minimum Required Value for Concrete Containment Tendon Prestress. LRA Section 4.5 states that to ensure the integrity of the containment pressure boundary under design basis accident loads, tendon surveillances are performed under the Inservice Inspection Program in accordance with ASME Code Section XI, Subsection IWL. Furthermore, the minimum required value is the average tendon prestress force used in the prestressed concrete containment design analysis. The design prestress must account for the loss of prestressing force after the initial tensioning, in accordance with RG 1.35.1, "Determining Prestressing Forces for Inspection of Prestressed Concrete Containments." The LRA also states that the minimum required value is the acceptance criterion for the average tendon prestressing force

over the entire plant life and does not vary with the plant life; therefore, the MRV is not a TLAA, in accordance with 10 CFR 54.3(a).

The staff's review of the applicant's claim that the minimum required value for concrete containment tendon prestress is not a TLAA is documented in SER Section 4.5.

Absence of a TLAA for Design Cycles for the Feedwater Penetrations. LRA Section 4.6.1 states that the analyses in BC-TOP-1 do not qualify the components on a generic basis. The staff noted that analyses must be performed, or at least the analyses in BC-TOP-1 must be confirmed to be conservative, on a plant-specific basis. The applicant stated that, for its plant, the specific analyses were performed for the main steam line penetrations and the feedwater penetrations. Furthermore, BC-TOP-1, Part II, analyzed "Loading Condition V," which compared the allowed value of the alternating stress range from the ASME Code Section III, I-9-1 diagram for 100 cycles to the maximum calculated alternating stress intensity for the load combination. The applicant stated that its plant-specific analysis determined that the feedwater penetrations would not exceed the primary plus secondary stress intensity ($3S_M$) requirement of ASME Code Section III, Subsection NB-3222.2 for "Loading Condition V" and does not require an elastic-plastic analysis for the feedwater penetrations. Thus, the analysis of the feedwater penetrations for "Loading Condition V" does not include a cyclic loading aging effect and is not a TLAA in accordance with 10 CFR 54.3(a).

The staff's review of the applicant's claim that the design cycles for the feedwater penetrations is not a TLAA is documented in SER Section 4.6.1.

Absence of a TLAA for Fracture Mechanics Analyses for Cold Leg Elbow-to-Safe End Weld Flaw Indications. LRA Section 4.7.2 states that operation with a crack is acceptable with respect to unstable ductile tearing mechanism if the applied J-integral remains below the J_{Ic} fracture toughness and the only aging mechanism that affects these criteria is thermal aging. It further states that the forged safe end material is not subject to thermal aging; the gas tungsten arc welds (GTAWs) are subject to thermal aging, but the effects are considered negligible. The applicant stated that the fracture mechanics analysis for these flaw indications do not consider aging effects and is not a TLAA, by 10 CFR 54.3(a), Criterion 2.

The staff noted that LRA Section 4.7.2 did not justify why the GTAWs are subject to thermal aging, but the effect is considered negligible. In addition, the LRA did not indicate if the statically cast stainless steel elbow is susceptible to thermal aging and why such fracture mechanics analysis is not a TLAA. By letter dated August 6, 2012, the staff issued request for additional information (RAI) 4.7.2-2 requesting the applicant justify that thermal aging on the GTAWs is considered negligible and justify why the fracture mechanics analysis did not consider thermal aging. The staff's evaluation of the applicant's response to RAI 4.7.2-2 and the applicant's claim that the fracture mechanics analysis for cold leg elbow-to-safe end weld flaw indications is not a TLAA is documented in SER Section 4.7.2.2. In addition, the staff's evaluation of the fatigue crack growth TLAA for cold leg elbow-to-safe end weld flaw indications is also documented in SER Section 4.7.2.2.

Absence of a TLAA for the Fracture Mechanics of the Reactor Coolant Loops Leak-Before-Break Analysis. LRA Section 4.7.7 states that the reactor coolant loop LBB analysis included a fracture mechanics analysis, which accounts for reduction in fracture toughness of the cast austenitic stainless steel (CASS) in the primary loops from thermal aging. The LRA further states that the fracture mechanics analysis was performed for a reference material with fully aged fracture toughness material properties. Therefore, the applicant

determined that since the fracture toughness material properties used in the analysis are not time-dependent, this analysis is not a TLAA because it does not conform to 10 CFR 54.3(a).

The staff noted that the evaluation of the fracture toughness property for CASS reactor coolant loop components in the LBB would not be time-dependent if the applicant's analysis assumed a lower-bound fracture toughness for the CASS components under assumed saturated thermal aging conditions. However, the staff also noted that the applicant's basis may be predicated on thermal aging data that are not up-to-date or conservative when compared to the most recent data for the industry. By letter dated August 6, 2012, the staff issued RAI 4.7.7-2 requesting the applicant to justify why the fracture toughness material properties used in the LBB analysis are not time dependent and whether the thermal aging data used in the analysis are up-to-date or conservative when compared to the most recent data for the state of the industry. The staff's evaluation of the applicant's response to RAI 4.7.7-2 and the applicant's claim that the fracture mechanics analysis of the reactor coolant loops LBB analysis is not a TLAA is documented in SER Section 4.7.7.2. In addition, the staff's evaluation of the fatigue crack growth TLAA of the reactor coolant loops LBB analysis also is documented in SER Section 4.7.7.2.

Absence of a TLAA for the Fracture Mechanics of the Leak Before Break Analyses for the Accumulator Injection and Residual Heat Removal Lines. LRA Section 4.7.7 states that Westinghouse performed LBB analyses of the 10 in. accumulator lines and the 12 in. residual heat removal (RHR) lines to minimize pipe breaks and reduce pipe whip restraints and jet shield, which would mitigate the dynamic consequences of the postulated breaks. It further states that the LBB analyses consist of fracture mechanics and fatigue crack growth analyses. The applicant stated that since the components in these lines and associated fittings are made from forged materials, they are not subject to thermal aging embrittlement. Therefore, the applicant stated that the fracture mechanics analyses in the LBB assessment are not TLAAs because they do not conform to 10 CFR 54.3(a), criterion 2.

The staff noted that, as described in the GALL Report, at operating temperatures of 250 to 343 degrees Celsius (°C) [500 to 650 degrees Fahrenheit (°F)], cast austenitic stainless steels exhibit a spinodal decomposition of the ferrite phase into ferrite-rich and chromium-rich phases. Furthermore, the phenomena may give rise to significant embrittlement (reduction in fracture toughness) caused by thermal aging, depending on the amount, morphology, and distribution of the ferrite phase and the alloying composition of the steel. The staff noted that since the accumulator injection and RHR lines, including associated fittings, at the applicant's site are forged components and do not contain a sufficient amount of the ferrite phase, thermal aging and spinodal decomposition, as described above, are not a concern for these reactor coolant pressure boundary (RCPB) piping lines. The staff finds that spinodal decomposition and thermal aging embrittlement are not applicable to these lines that only include forging materials. It also finds that the Westinghouse fracture mechanics analysis is not applicable to these lines and does not need to be identified as a TLAA. The staff's evaluation of the fatigue crack growth TLAA of the LBB analyses for the accumulator injection and RHR lines is documented in SER Section 4.7.7.2.

4.1.2.2 Identification of Exemptions in the LRA

LRA Section 4.1.2 states that 10 CFR 54.21(c)(2) requires a list of plant-specific exemptions granted in accordance with 10 CFR 50.12 and in effect that are based on TLAAs as defined in 10 CFR 54.3. It further states that an evaluation that justifies the continuation of these exemptions for the period of extended operation shall be provided. The staff noted that docketed correspondence, the operating license, and the FSAR were searched by the applicant

to identify exemptions in effect, and each exemption in effect was then evaluated to determine if it involved a TLAA as defined in 10 CFR 54.3.

The applicant stated that only two exemptions “currently in effect” are based, in part, on a TLAA, which include the use of the LBB evaluation of RCS piping and the use of ASME Code Case N-514. The staff noted that the first exemption based on a TLAA relates to the staff’s permission to use the LBB evaluation as the basis for being exempt to the dynamic effect protection requirements in 10 CFR Part 50, Appendix A, “General Design Criteria for Nuclear Power Plants,” Criterion 4, “Environmental and Dynamic Effects Design Bases.” The applicant’s evaluation of the LBB TLAA for the main coolant loops, accumulator line, and RHR line in the RCPB is described in LRA Section 4.7.7. The staff’s evaluation of the leak before break TLAA is documented in SER Section 4.7.7.2. In addition, it was noted that in the second exemption that ASME Code Case N-514 supports the implementation of the LTOP limits. The applicant’s evaluation of the methodology, consistent with WCAP-14040-NP-A and ASME Code Case N-514, to determine the cold overpressure mitigation system pressurizer power operated relief valve (PORV) setpoints is described in LRA Section 4.2.5. The staff’s evaluation of the low temperature overpressure protection TLAA is documented in SER Section 4.2.5.2.

The staff reviewed the applicant’s FSAR and, in addition to the two above-mentioned exemptions, the staff identified other exemptions discussed in FSAR Section 16.6.1.1.2. This FSAR Section states the following exemptions have been granted to the requirements of Appendix J of 10 CFR Part 50:

- Section III.A.1(a) — an exemption to the requirement to stop the Type A test if excessive leakage is determined. This exemption allows the satisfactory completion of the Type A test if the leakage can be isolated and appropriately factored into the results.
- Section III.A.5(b) — an exemption for the acceptance criteria, in lieu of the present single criterion of the total measured containment leakage rate being less than 0.75 of the maximum allowable leakage rate (L_a), the "as found" allowable leakage rate will be La and the "as left" allowable leakage rate will be less than 0.75 L_a.
- Section III.D.1(a) — an exemption that removes the requirement that the third test of each set of three Type A tests be conducted when the plant is shut down for the 10-year plant inservice inspection.

The staff reviewed FSAR Section 16.6.1.1.2 and the applicable sections of Appendix J of 10 CFR Part 50, and it determined that these exemptions are not based on an aging effect or any analysis that is a TLAA for the LRA. Thus, these exemptions do not meet the criteria of a TLAA, as defined in 10 CFR 54.3(a), and do not need to be identified in accordance with 10 CFR 54.21(c)(2).

4.1.3 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable list of TLAAs, as required by 10 CFR 54.21(c)(1). The staff concludes 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 reactor vessel beltline region, as defined in 10 CFR Part 50, Appendix G, "Fracture Toughness Requirements," for light-water nuclear power reactors. In addition to the ASME Code Section III requirements, the reactor vessel materials must maintain adequate fracture toughness during both normal and off-normal operating conditions (e.g., upset, emergency, and faulted conditions) to ensure the structural integrity of the reactor vessel during the period of extended operation.

LRA Section 4.2 provides the applicant's analyses of the following areas related to reactor vessel neutron embrittlement:

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

10 CFR Part 50, Appendix G, specifies fracture toughness requirements for ferritic pressure-retaining components that make up the RCPB of light-water nuclear reactors, including requirements for Charpy upper-shelf energy (USE) and P-T limits. The rule states that reactor vessel beltline material properties, including the nil-ductility reference temperature (RT_{NDT}) values and Charpy USE values, must account for the effects of neutron irradiation. The staff's guidelines for neutron embrittlement calculations are established in RG 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," dated May 1988. RG 1.99 specifies the methods for calculating the projected adjustment to the RT_{NDT} values (adjusted RT_{NDT}) and the projected decrease in the Charpy USE values for reactor vessel beltline materials caused by neutron irradiation during the operating life of the plant.

Regulations in 10 CFR 50.61, "Fracture Toughness Requirements for Protection against Pressurized Thermal Shock Events," provide requirements for ensuring the resistance of reactor vessel beltline materials against pressurized thermal shock (PTS) events, as applicable only to PWR plants. The PTS rule characterizes the toughness of reactor vessel beltline materials by the reference temperature for PTS (RT_{PTS}) which is defined as the RT_{NDT} value evaluated for the projected end-of-life (EOL) fluence or, for license renewal, the projected end-of-life-extended (EOLE) neutron fluence, at the reactor vessel stainless steel clad-to-low-alloy steel (clad/base metal) interface. Procedures in 10 CFR 50.61 for calculating RT_{PTS} are the same as those established in RG 1.99 for calculating the adjusted RT_{NDT}.

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 the neutron fluence values. The applicant stated that neutron fluence projections are made to analyze neutron embrittlement effects on Charpy USE and RT_{PTS}. The applicant also stated that fluence projections were calculated based on a conservatively assumed plant lifetime capacity factor of 90 percent, which corresponds to 54 effective full power years (EFPYs) of facility operation for 60 calendar years of operation, also referred to as EOLE.

According to the applicant, the fluence values for EOLE were projected based on the results of the analysis for reactor vessel surveillance Capsule X (Capsule X), as documented in WCAP-15400-NP, "Analysis of Capsule X from the Ameren UE Callaway Unit 1 Reactor Vessel Surveillance Program," June 2000. The applicant stated that the 54 EFPY fluence projections were determined based on neutron transport calculations using the discrete ordinates code, DORT, with the BUGLE-96 cross-section library, which is derived from ENDF/B-VI scattering cross-section data set. The applicant further stated that these neutron transport and dosimetry evaluation methodologies follow the guidance of RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," dated March 2001, and are consistent with the fluence methodology described in WCAP-14040-A, "Methodology Used To Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves," Revision 4, dated May 2004. The applicant provided peak neutron fluence values, projected to 54 EFPY, for the reactor vessel beltline and extended beltline materials in LRA Tables 4.2-1 and 4.2-2.

The applicant dispositioned the TLAA for the neutron fluence values in accordance with 10 CFR 54.21(c)(1)(ii), that the neutron fluence analysis has been projected to the end of the period of extended operation.

4.2.1.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the neutron fluence values and the corresponding disposition of 10 CFR 54.21(c)(1)(ii), consistent with the review procedures in SRP-LR Section 4.7.3.1.2, which state that the documented results of the revised analyses are reviewed to verify that their period of evaluation is extended, such that they are valid for the period of extended operation (e.g., 60 years). The SRP-LR also states that the applicable analysis technique can be the one that is in effect in the plant's CLB at the time of filing of the LRA.

The analysis technique for determining the 54 EFPY fluence values is the same as the one that is currently in effect in the Callaway CLB. Specifically, the staff confirmed that the 54 EFPY neutron fluence values for the Callaway reactor vessel beltline and extended beltline materials were calculated using the same staff-approved neutron fluence methodology that is currently approved in the CLB for calculating beltline material adjusted RT_{NDT} values for P-T limit curves. The neutron transport and dosimetry evaluation methodologies follow the guidance of RG 1.190 and are consistent with the neutron fluence calculation methods established in the staff-approved P-T limits report (PTLR) methodology for Westinghouse plants, WCAP-14040-A, Revision 4.

The WCAP-14040-A, Revision 4 PTLR methodology for Westinghouse plants discusses the methods for plant-specific neutron transport calculations and the validity of the calculations. For the neutron transport calculations, the WCAP-14040-A, Revision 4 PTLR methodology implements the two-dimensional discrete ordinates code, DORT, with the BUGLE-96 cross section library, which is derived from ENDF/B-VI scattering cross-section data set. As discussed in its February 27, 2004, Final Safety Evaluation (SE) for WCAP-14040-A, Revision 4, the staff determined that the above neutron fluence calculation methodology adheres to the guidance of RG 1.190 and is acceptable for implementation without conditions by Westinghouse plants implementing the WCAP-14040-A methodology for calculating P-T limit curves.

LRA Tables 4.2-1 and 4.2-2 provide peak neutron fluence projections for EOLE (54 EFPY) at the reactor vessel clad/base metal interface for the reactor vessel beltline and extended beltline regions, respectively. The staff noted that the applicant applied a neutron fluence threshold of

1×10^{17} n/cm^2 (E greater than 1.0 MeV) to define the reactor vessel beltline and extended beltline materials subject to neutron embrittlement analysis in LRA Section 4.2. The staff finds that the applicant's definition of the RV beltline region includes those materials previously analyzed for neutron embrittlement for the CLB through 35 EFPY. The applicant's definition of the extended beltline region includes materials outside the CLB beltline region that have projected neutron fluence exposure greater than 1×10^{17} n/cm^2 (E greater than 1.0 MeV) for the period of extended operation.

The fluence threshold for identifying the reactor vessel beltline materials is defined in the GALL Report as 1×10^{17} n/cm^2 (E greater than 1.0 MeV) at the end of the period of extended operation. This fluence threshold is based on the Reactor Vessel Material Surveillance Program requirements of 10 CFR Part 50, Appendix H, "Reactor Vessel Material Surveillance Program Requirements," which requires monitoring the changes in fracture toughness parameters caused by neutron embrittlement for all reactor vessel materials projected to experience neutron fluence greater than 1×10^{17} n/cm^2 (E greater than 1.0 MeV) at the expiration of the facility operating license. Therefore, the staff finds the applicant's definition of the reactor vessel beltline and extended beltline regions acceptable because it is consistent with guidance provided in the GALL Report.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(ii), that the analysis for determining the reactor vessel neutron fluence values and defining the reactor vessel beltline and extended beltline regions has been adequately projected to the end of the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.7.2.1 because the applicant's analysis for determining the neutron fluence values and defining the beltline and extended beltline regions of the reactor vessel has been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

4.2.1.3 FSAR Supplement

LRA Section A3.1.1 provides the FSAR supplement summarizing the neutron fluence TLAA. The staff reviewed LRA Section A3.1.1 consistent with the review procedures in SRP-LR Section 4.7.3.2, which state that the FSAR supplement is reviewed to verify that the applicant has provided an appropriate summary description of the evaluation of the TLAA, including the applicant's disposition of the TLAA for the period of extended operation.

Based on its review of the FSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.7.2.2, and is therefore acceptable. Additionally, the staff finds that the applicant provided an adequate summary description of its actions to address neutron fluence for the period of extended operation, as required by 10 CFR 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, in accordance with 10 CFR 54.21(c)(1)(ii), that the analysis for determining the reactor vessel neutron fluence values and defining the reactor vessel beltline and extended beltline regions has been adequately projected to the end of the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.2 Charpy Upper-Shelf Energy

4.2.2.1 Summary of Technical Information in the Application

LRA Section 4.2.2 describes the applicant's TLAA for Charpy USE. The applicant stated that the USE results from Capsule X are reported in WCAP-15400-NP. According to the applicant, the Charpy test results were deemed to be credible and show that the decline in USE for the surveillance plate and weld materials are less than originally predicted by RG 1.99, demonstrating that the reactor vessel materials age consistently with RG 1.99 predictions and provide assurance of reactor vessel integrity.

The applicant stated that the USE values for the reactor vessel beltline and extended beltline materials were projected to the end of the period of extended operation in WCAP-17168-NP, "Callaway Unit 1 Time-Limited Aging Analysis on Reactor Vessel Integrity," September 2010. These USE calculations are summarized in LRA Table 4.2-3. According to the applicant, the most limiting value of EOLE USE for any of these materials is 61 ft-lbs for Intermediate Shell Plate R2707-1. The applicant stated that this satisfies the 10 CFR Part 50, Appendix G EOL (or EOLE) USE acceptance criterion of 50 ft-lbs.

The applicant dispositioned the TLAA for the Charpy USE in accordance with 10 CFR 54.21(c)(1)(ii), that the USE analysis has been projected to the end of the period of extended operation.

4.2.2.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the Charpy USE and the corresponding disposition of 10 CFR 54.21(c)(1)(ii), 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. The SRP-LR also states that the applicant may use RG 1.99 to project USE to the end of the period of extended operation, or the applicant also may use the ASME Code Section XI, Appendix K, for the purpose of performing an equivalent margins analysis (EMA) to demonstrate that adequate protection against ductile failure is maintained to the end of the period of extended operation.

10 CFR Part 50, Appendix G specifies that reactor vessel beltline materials must maintain Charpy USE values of no less than 50 ft-lbs throughout the operating life of the facility, unless it is demonstrated through an EMA that adequate protection against ductile failure is maintained to the end of the period of extended operation. Therefore, for the reactor vessel beltline materials, EMAs are required only if the projected USE values at EOLE cannot be shown to be greater than or equal to 50 ft-lbs.

In LRA Table 4.2-3, the applicant provided 54 EFPY USE values for all RV beltline and extended beltline materials. All 54 EFPY USE values are projected to remain greater than 50 ft-lbs, as required by 10 CFR Part 50, Appendix G. The limiting (lowest) 54 EFPY USE value is 61 ft-lbs for Intermediate Shell Plate R2707-1. The staff independently confirmed that all projected USE values were accurately calculated using the procedures in RG 1.99, Position 1.2, which is used for materials without credible surveillance data. For those reactor vessel beltline materials represented in the Reactor Vessel Materials Surveillance Program, (Lower Shell Plate R2708-1 and all beltline shell welds), LRA Table 4.2-3 also lists 54 EFPY values that were calculated using the procedures in RG 1.99, Position 2.2. The staff also confirmed the accuracy of these calculations and noted that the 54 EFPY USE values for the surveillance materials,

based on Position 2.2 of RG 1.99, exceed those calculated using Position 1.2, thereby demonstrating additional conservatism in the RG 1.99, Position 1.2 calculation.

The following inputs are required to project EOLE USE using the methods specified in RG 1.99, Position 1.2: neutron fluence at a location corresponding to one-quarter of the RV wall thickness from the RV clad/base metal interface (heretofore referred to as the 1/4T location); the material's percentage copper (Cu) content by weight; and the unirradiated (initial) USE value for the material. The staff confirmed that 54 EFPY fluence values at the 1/4T location were appropriately used for the EOLE USE calculations. The staff confirmed that the initial USE values and the weight percentage Cu content listed in LRA Table 4.2-3 for the RV beltline materials are consistent with those listed in the staff's reactor vessel integrity database (RVID) and in previously docketed correspondence. For the extended beltline materials [i.e., those materials projected to exceed the 1×10^{17} n/cm^2 (E greater than 1.0 MeV) neutron fluence threshold during the period of extended operation] the staff found no documentation of the initial USE values and Cu contents in the RVID or in previously docketed correspondence. Furthermore, the LRA did not include any information regarding the heat (defined as a production run of homogeneous metal from a period of continuous melting in a cupola or furnace), nor the material specification or weld type, for any of the extended beltline components. Therefore, to obtain reasonable assurance concerning the identification of the extended beltline components and their associated material properties, by letter dated June 22, 2012, the staff issued RAIs 4.2.2-1 requesting that the applicant provide this information for the extended beltline materials.

In RAI 4.2.2-1, Part (a), the staff requested that the applicant identify the material specifications for the reactor vessel nozzle shell plates and the inlet and outlet nozzle forgings, based on the ASME Code Section II standards. In its RAI response, dated July 20, 2012, the applicant stated that the nozzle shell plates are SA-533B, Class 1 plate material, and the inlet and outlet nozzle forgings are SA-508 Class 2 forging material. The staff found the applicant's response to RAI 4.2.2-1, Part (a), acceptable because the applicant identified the appropriate ASME Code Section II, material specification for the reactor vessel nozzle shell plates and inlet/outlet nozzle forgings. Therefore, the staff's concern described in RAI 4.2.2-1, Part (a), is resolved.

In RAI 4.2.2-1, Part (b), the staff requested that the applicant identify the weld fabrication method and flux type for the nozzle-shell-to-intermediate-shell weld and the inlet and outlet nozzle-to-shell welds. In its RAI response, dated July 20, 2012, the applicant provided a table identifying the weld fabrication method and flux type for all extended beltline welds, which includes the nozzle shell-to-intermediate-shell welds, the inlet and outlet nozzle-to-shell welds, as well as the nozzle shell longitudinal welds. According to the applicant, all extended beltline welds were fabricated by either the shielded metal arc welding (SMAW) or the submerged arc welding (SAW) process. Flux types (Linde 0091 or Linde 124) were listed for all SAW-fabricated welds. For the SMAW-fabricated welds, a welding flux is not used because this process uses a coated electrode to create an inert environment to protect the weld from impurities during fabrication. The staff found the applicant's response to RAI 4.2.2-1, Part (b) acceptable because the applicant appropriately identified the weld fabrication method and flux type for all extended beltline welds. Therefore, the staff's concern described in RAI 4.2.2-1, Part (b), is resolved.

In RAI 4.2.2-1, Part (c), the staff requested that the applicant identify: (i) the heat numbers for all extended beltline plates and forgings, and the weld wire heat number and flux lot number for all extended beltline welds; and (ii) the source of the initial USE and Cu content data listed in LRA Table 4.2-3. If the initial USE and Cu content data are not based on measured

heat-specific values from certified material test reports (CMTRs), the staff requested that the applicant provide justification for using these values. In its RAI response, dated July 20, 2012, the applicant provided a table identifying the heat numbers for all extended beltline materials, including plates, forgings, and weld wires. For the SAW-fabricated welds, the applicant included the welding flux lot numbers. The applicant noted that each individual extended beltline weld component identified in the LRA is fabricated from multiple heat numbers of weld wire with differing USE values and Cu contents. The applicant stated that for each extended beltline weld, the most limiting values for the initial USE and Cu content are chosen for the EOLE USE calculation in LRA Table 4.2-3. Regarding the source of the initial USE values, the applicant stated that, with the exception of the Linde 0091 welds of Heat No. 4P7656 (Flux Lot No. 1054), the initial USE values listed in LRA Table 4.2-3 for all reactor vessel extended beltline materials are based on heat-specific CMTRs. The applicant stated that the Linde 0091 welds of Heat No. 4P7656 (Flux Lot No. 1054) used a generic initial USE value of 101 ft-lbs that is based on CEN-622-A Final Report, "Generic Upper Shelf Values for Linde 1092, 124, and 0091 Reactor Vessel Welds, CEOG Task 839," June 30, 1995 (ADAMS Legacy Library Accession No. 9508020111). The staff confirmed that the NRC-approved CEN-622-A report provides a conservative statistical basis for the generic initial USE value of 101 ft-lbs for the Linde 0091 welds of heat No. 4P7656 (Flux Lot No. 1054), and therefore 101 ft-lbs is an acceptable generic initial USE for these particular welds. Accordingly, the staff determined that the applicant adequately identified the basis for the extended beltline material initial USE values listed in LRA Table 4.2-3. The staff's concern described in RAI 4.2.2-1, Part (c), is resolved.

Regarding the source of the Cu content data, the applicant stated that, with the exception of the inlet and outlet nozzle forgings, the Cu content values listed in LRA Table 4.2-3 for all extended beltline materials are based on heat-specific CMTRs. The applicant stated that the CMTRs for the inlet and outlet nozzles did not contain measurements of Cu content because it was not required. Instead, the applicant invoked a generic Cu content of 0.16 percent for all inlet and outlet nozzle forgings — eight nozzle forgings total. The applicant stated that the 0.16 percent Cu content was taken from the analysis of chemistry measurements made for archived PWR surveillance capsule materials. The applicant indicated that the chemistry measurements for SA-508, Class 2, forgings are provided in Oak Ridge National Laboratory (ORNL) Report ORNL/TM-2006/530, "A Physically Based Correlation of Irradiation-Induced Transition Temperature Shifts for RPV Steels," dated November 30, 2007.

To determine if these chemistry measurements were analyzed properly to arrive at the generic Cu content of 0.16 percent, by letter dated September 12, 2012, the staff issued RAI 4.2.2-1a, requesting that the applicant provide additional justification based on statistical analysis for the selection of a 0.16 percent Cu content for the SA-508, Class 2, inlet and outlet nozzles. By letter dated October 15, 2012, the applicant provided its response to RAI 4.2.2-1a. In its RAI response, the applicant stated that ORNL Report ORNL/TM-2006/530 provides the mean, standard deviation (σ), minimum, and maximum Cu values for the SA-508, Class 2, forging data analyzed in the report. The applicant noted that the mean value for the Cu content is 0.1220 percent, with a σ of 0.0313 percent, resulting in a mean + 2σ upper bound value of 0.1846 percent. The applicant stated that the USE and PTS calculations for the reactor vessel inlet and outlet nozzles are revised to incorporate the 0.1846 percent Cu content for these nozzle forgings. The staff finds the applicant's response to RAI 4.2.2-1a acceptable because the applicant invoked the mean + 2σ upper bound value for establishing the 0.1846 percent generic Cu content for its inlet and outlet nozzles forgings. The staff noted that the generic Cu content of 0.1846 percent is a statistically conservative value that is consistent with statistical analyses performed on industry-wide data. The applicant's response also included LRA Amendment 12, which revised LRA Tables 4.2-3 and 4.2-4 to include revised USE and RT_{PTS}

calculations for the reactor vessel inlet and outlet nozzles based on the revised generic Cu content value of 0.1846 percent for SA-508, Class 2 nozzle forgings. The staff noted that the EOLE USE values for these nozzles, based on the revised Cu content, remain significantly greater than the EOLE 50 ft-lb threshold specified in 10 CFR Part 50, Appendix G. Therefore, the staff's concern described in RAI 4.2.2-1a is resolved.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(ii), that the analysis of Charpy USE for the reactor vessel beltline and extended beltline components has been projected to the end of the period of extended operation. Additionally, the staff finds that the applicant's analysis of Charpy USE meets the acceptance criteria in SRP-LR Section 4.2.2.1.1.2 because the Charpy USE values for the reactor vessel beltline and extended beltline components have been appropriately evaluated for the period of extended operation and found to remain in compliance with 10 CFR Part 50, Appendix G.

4.2.2.3 FSAR Supplement

LRA Section A3.1.2 provides the FSAR supplement summarizing the Charpy USE 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 FSAR supplement is reviewed to verify that the applicant has provided an appropriate summary description of the evaluation of the reactor vessel neutron embrittlement TLAA.

Based on its review of the FSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.2.2.2 and is therefore acceptable. Additionally, the staff finds that the applicant provided an adequate summary description of its actions to address Charpy USE for the period of extended operation, as required by 10 CFR 54.21(d).

4.2.2.4 Conclusion

On the basis of its review, the staff concludes that, the applicant has provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(ii), that the analysis of Charpy USE for the reactor vessel beltline and extended beltline components has been projected to the end of the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.3 Pressurized Thermal Shock

4.2.3.1 Summary of Technical Information in the Application

LRA Section 4.2.3 describes the applicant's TLAA for PTS. The applicant stated that the CLB RT_{PTS} assessment is based on a 35 EFPY operating life and is documented in FSAR Table 5.3-9 and the Callaway PTLR. The applicant stated that the surveillance specimen examination results are credible and show that the RT_{PTS} values for the surveillance plate and weld materials are in good agreement with or less than the RG 1.99, Position 1.1 predictions, thereby demonstrating conservatism in the Position 1.1 predictions.

The applicant stated that the reactor vessel beltline and extended beltline materials were evaluated for PTS in WCAP-17168-NP. These RT_{PTS} calculations are summarized in LRA Table 4.2-4. According to the applicant, the most limiting predicted RT_{PTS} value for the period of extended operation is 49 °C (120 °F) for Lower Shell Plate R2708-3, based on the methods of RG 1.99, Position 1.1. The applicant stated that the RT_{PTS} values for all beltline and extended beltline materials meet the PTS screening criteria of 10 CFR 50.61.

The applicant dispositioned the TLAA for PTS in accordance with 10 CFR 54.21(c)(1)(ii), that the PTS analysis has been projected to the end of the period of extended operation.

4.2.3.2 Staff Evaluation

The staff reviewed the applicant's TLAA for PTS and the corresponding disposition of 10 CFR 54.21(c)(1)(ii), 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.

10 CFR 50.61 requires that PWR facilities have projected values of RT_{PTS} that are accepted by the staff for each reactor vessel beltline material. The RT_{PTS} assessment shall follow the calculation procedures specified in 10 CFR 50.61(c), which are the same as the methods described in RG 1.99 for calculating the adjusted RT_{NDT}. RT_{PTS} calculations account for the effects of neutron embrittlement; to verify that the calculations provide values that are bounding for each reactor vessel material, applicant's shall consider plant-specific information that could affect the level of embrittlement, such as the reactor vessel operating temperature and any related reactor vessel surveillance capsule data, including data from the applicant's implementation of its Reactor Vessel Materials Surveillance Program. Regulations in 10 CFR 50.61 define the RT_{PTS} as the RT_{NDT} evaluated for the EOL (or EOLE) neutron fluence at the clad/base metal interface for the reactor vessel beltline materials. RT_{PTS} values for reactor vessel beltline materials shall not exceed the screening criteria specified in 10 CFR 50.61(b)(2), except as provided in 10 CFR 50.61(b)(3) – (b)(7). The PTS screening criteria are 132 °C (270 °F) for reactor vessel plates, forgings, and axial welds, and 149 °C (300 °F) for circumferential welds.

The staff reviewed the applicant's RT_{PTS} calculations for the period of extended operation against the screening criteria in 10 CFR 50.61(b)(2). The staff used the applicant's 60-year projected neutron fluence values for the reactor vessel beltline and extended beltline materials from LRA Tables 4.2-1 and 4.2-2 as the basis for determining if the reactor vessel beltline materials would have acceptable RT_{PTS} values for the period of extended operation.

LRA Table 4.2-4 lists 54 EFPY RT_{PTS} values for all reactor vessel beltline and extended beltline materials, including the input data used in the calculations. All 54 EFPY RT_{PTS} values are projected to remain less than the applicable screening criteria of 10 CFR 50.61(b)(2). The limiting (highest) 54 EFPY RT_{PTS} value listed in LRA Table 4.2-4 is 49 °C (120 °F) for Lower Shell Plate R2708-3, based on the methods specified in 10 CFR 50.61(c)(1) (equivalent to the procedures in RG 1.99, Position 1.1), which is used for materials without credible surveillance data. The staff confirmed that all 54 EFPY RT_{PTS} values are correctly calculated using the methods specified in 10 CFR 50.61(c)(1). For those reactor vessel beltline materials represented in the Reactor Vessel Materials Surveillance Program, (Lower Shell Plate R2708-1 and all beltline shell welds), LRA Table 4.2-4 also lists 54 EFPY values that are calculated using the procedures in 50.61(c)(2) (equivalent to the procedures in RG 1.99, Position 2.1). The staff also confirmed the accuracy of these calculations and noted that the 54 EFPY RT_{PTS} value for Lower Shell Plate R2708-1 of 38 °C (100 °F), based on Position 2.1 of RG 1.99, is significantly less than that calculated using Position 1.1, thereby demonstrating conservatism in the Position 1.1 calculation.

The following inputs are required to project RT_{PTS} using the methods specified in RG 1.99, Position 1.1: EOLE (54 EFPY) neutron fluence at the reactor vessel clad/base metal interface, the material's weight percentage Cu and Ni content, the unirradiated (initial) RT_{NDT} value for the

material, and the margin term. The staff confirmed that 54 EFPY fluence values at the clad/base metal interface of the RV wall were appropriately used for the RT_{PTS} calculations. The staff confirmed that the initial RT_{NDT} values and the Cu and Ni contents listed in LRA Table 4.2-4 for the RV beltline materials are consistent with those listed in the staff's RVID and in previously docketed correspondence regarding P-T limit curves. Calculated margin term values for the RV beltline materials also were found to be consistent with previously docketed correspondence and RG 1.99. For the extended beltline materials (i.e., those materials projected to exceed the 1×10^{17} n/cm^2 (E greater than 1.0 MeV) neutron fluence threshold during the period of extended operation), the staff found no documentation of the initial RT_{NDT} values and Cu and Ni contents. Therefore, by letter dated June 22, 2012, the staff issued RAI 4.2.3-1 requesting that the applicant identify the source of the initial RT_{NDT} and Nickel (Ni) content data for all extended beltline materials. The issue of the Cu content data for the extended beltline materials was previously addressed in RAIs 4.2.2-1 and.4.2.2-1a which are discussed in SER Section 4.2.2.2. In the RAI, the staff noted that, if the initial RT_{NDT} and Ni content data are not based on measured heat-specific values from CMTRs, then the applicant should provide justification for using these values.

In its RAI response, dated July 20, 2012, the applicant stated that the initial RT_{NDT} and Ni content for all extended beltline materials are based on heat-specific CMTRs. The applicant noted that each individual extended beltline weld component identified in the LRA is fabricated from multiple heat numbers of weld wire with differing initial RT_{NDT} values and Cu and Ni contents. The applicant stated that for each extended beltline weld, the most limiting value for the initial RT_{NDT} is chosen for the RT_{PTS} calculation in LRA Table 4.2-4. To account for varying chemical content of the weld heats, the applicant stated that for each extended beltline weld, a chemistry factor (CF) is calculated for each heat based on the measured Cu and Ni content using the procedures in RG 1.99, Position 1.1, and the most limiting CF of all the weld's heats is used for the RT_{PTS} calculation for the weld in LRA Table 4.2-4.

The staff found the applicant's RAI response acceptable because the applicant confirmed that the initial RT_{NDT} and Ni content for all extended beltline materials are based on heat-specific CMTRs. Furthermore, based on its review of the RAI response, the staff determined that the extended beltline weld RT_{PTS} values listed in LRA Table 4.2-4 were calculated using the most limiting initial RT_{NDT} and CF values for the various weld wire heads from which the welds were fabricated. Therefore, the staff's concern described in RAI 4.2.3-1 is resolved.

As discussed in SER Section 4.2.2.2, the applicant has revised the generic Cu content for the inlet and outlet nozzle forgings from 0.16 percent to the statistically determined value of 0.184 percent. LRA Amendment 12 revised LRA Tables 4.2-3 and 4.2-4 to include revised USE and RT_{PTS} calculations for the RV inlet and outlet nozzles based on this revised Cu content. The staff noted that the 54 EFPY RT_{PTS} values for these nozzles, based on the revised Cu content, remain significantly less than the RT_{PTS} screening criterion of 132 °C (270 °F) specified in 10 CFR 50.61(b).

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(ii), that the analysis of RT_{PTS} for the reactor vessel beltline and extended beltline components has been projected to the end of the period of extended operation. Additionally, the staff finds that the applicant's PTS analysis meets the acceptance criteria in SRP-LR Section 4.2.2.1.2.2 because the RT_{PTS} values for the RV beltline and extended beltline components have been evaluated for the period of extended operation and found to remain in compliance with 10 CFR 50.61.

4.2.3.3 FSAR Supplement

LRA Section A3.1.3 provides the FSAR supplement summarizing the PTS 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 FSAR supplement is reviewed to verify that the applicant has provided an appropriate summary description of the evaluation of the reactor vessel neutron embrittlement TLAA.

Based on its review of the FSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.2.2.2 and is therefore acceptable. Additionally, the staff finds that the applicant provided an adequate summary description of its actions to address PTS for the period of extended operation, as required by 10 CFR 54.21(d).

4.2.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(ii), that the analysis of PTS for the reactor vessel beltline and extended beltline components has been projected to the end of the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.4 Pressure-Temperature (P-T) Limits

4.2.4.1 Summary of Technical Information in the Application

LRA Section 4.2.4 describes the applicant's TLAA for the P-T limits. The applicant stated that the methods used to develop the Callaway P-T limit curves are based on the adjusted RT_{NDT} value for the limiting reactor vessel beltline material. The applicant also stated that withdrawal and testing of the surveillance specimens verifies that the limiting adjusted RT_{NDT} value used for calculating the P-T limit curves bounds the aging of the reactor vessel beltline materials. Adjusted RT_{NDT} values for the reactor vessel beltline materials are listed in the Callaway PTLR.

The applicant stated that the current P-T limit curves and adjusted RT_{NDT} values are valid up to 28 EFPY, based on a peak clad/base metal interface neutron fluence of 1.625×10^{19} n/cm^2 (E greater than 1.0 MeV), as determined from the analysis of Capsule X in WCAP-15400-NP. The applicant also stated that the current P-T limit curves are calculated based on adjusted RT_{NDT} values of 53 °C (128 °F) at the 1/4T location and 44 °C (112 °F) at three-quarters of the RV wall thickness from the RV clad/base metal interface (heretofore referred to as the 3/4T location) for the limiting beltline material, Lower Shell Plate R2708-1. According to the applicant, the current P-T limit curves were generated based on the methodologies of the ASME Code Section XI, Appendix G and WCAP-14040-A, Revision 4. The applicant further stated that the P-T limit curves are required to be maintained and updated as necessary by the administrative controls in Callaway Technical Specifications (TS), Section 5.6.6, and that it will revise the P-T limit curves before reaching 28 EFPY.

The applicant dispositioned the TLAA for the P-T limits in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of neutron embrittlement on the P-T limits will be adequately managed by the TS 5.6.6 administrative controls for the period of extended operation.

4.2.4.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the P-T limits and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with the review procedures in SRP-LR Section 4.2.3.1.3.3, which state that updated P-T limits for the period of extended operation must be available before entering the period of extended operation. SRP-LR Section 4.2.3.1.3.3 also states that either the 10 CFR 50.90 process for P-T limits located in the TS limiting conditions of operation (LCOs) or the TS administrative controls process for P-T limits contained in PTLRs can be considered adequate aging management programs (AMPs) within the scope of 10 CFR 54.21(c)(1)(iii), such that P-T limits will be appropriately maintained through the period of extended operation.

10 CFR Part 50, Appendix G, provides fracture toughness requirements for ferritic materials in the RCPB, including requirements for calculating the RCS P-T limits. Section IV.A.2 of 10 CFR Part 50, Appendix G, requires that P-T limits be at least as conservative as those determined in accordance with the ASME Code Section XI, Appendix G. The P-T limits shall also incorporate a 22 °C (40 °F) temperature adjustment above the ASME Code Section XI, Appendix G, limits for core criticality and incorporate the minimum temperature requirements, as specified in 10 CFR Part 50, Appendix G, Table 1. Additionally, 10 CFR Part 50, Appendix G, requires that the P-T limit calculations account for the effects of neutron irradiation on the properties of the reactor vessel beltline materials and that these calculations incorporate relevant reactor vessel surveillance capsule data. Since the adjusted RT_{NDT} values for reactor vessel beltline beltline materials increase as a function of neutron fluence, which changes with time, the P-T limits must be periodically updated to ensure that they bound the plant's operating conditions.

The current Callaway P-T limits, valid through 28 EFPY, are established in Revision 5 of the Callaway PTLR, which was submitted to the staff by letter dated January 5, 2007. The content of the Callaway PTLR is administratively controlled in accordance with Callaway TS 5.6.6. TS 5.6.6a specifies that P-T limits, including heatup and cooldown rates, shall be established and documented in the PTLR for heatup and cooldown operations, low-temperature conditions, core criticality, and hydrostatic testing, for operation of the RCS in accordance with TS LCO 3.4.3. LCO 3.4.3 specifies that RCS pressure, temperature, and heatup and cooldown rates shall be maintained within the limits specified in the PTLR at all times. TS 5.6.6b specifies the analytical methods used to calculate the P-T limits and the LTOP system setpoints contained in the PTLR — specifically the staff-approved methods of WCAP-14040-A, Revision 4. TS 5.6.6c requires that the PTLR be provided to the staff upon issuance for each reactor vessel neutron fluence period and for any revision or supplement thereto, thereby meeting the acceptance criterion from SRP-LR Section 4.2.2.1.3.3. SRP-LR Section 4.2.2.1.3.3 allows the P-T limits to be managed by the TS administrative controls process for P-T limits contained in PTLRs. The applicant will update the PTLR for new neutron fluence limits before operating beyond the current period.

Table 5.0-5 of the Callaway PTLR lists 28 EFPY adjusted RT_{NDT} values at the 1/4T and 3/4T locations for all reactor vessel materials that were established as beltline materials for the current licensing basis. This list does not include those components designated in the LRA as extended beltline materials. The staff found that the 28 EFPY P-T limits are calculated based on the adjusted RT_{NDT} values for the limiting reactor vessel beltline material. Table 5.0-6 of the Callaway PTLR shows the detailed adjusted RT_{NDT} calculations for the limiting beltline material, based on the methods of RG 1.99, Position 1.1. For the current PTLR, the staff noted that the

applicant conservatively selected Position 1.1 for calculating the limiting adjusted RT_{NDT} values even though the RG 1.99, Position 2 values for this material are significantly less.

The staff noted that the current Callaway PTLR (Revision 5) documents CF calculations based on the application of surveillance data from capsules "U," "Y," "V," and "X" using the methods in RG 1.99, Position 2.1. Section 4.0 of the Callaway PTLR states that all of the measured shifts in the RT_{NDT} for the surveillance plate and weld materials are deemed credible based on the RG 1.99 surveillance data credibility assessment.

By letter dated July 9, 2012, the staff issued RAI 4.2.4-1, requests (a), (b), (c), and (d). The applicant responded to RAI 4.2.4-1 by letter dated August 9, 2012. A discussion of each RAI 4.2.4-1 request and the applicant's response follows.

In RAI 4.2.4-1, Part (a), the staff requested that the applicant confirm whether surveillance Capsule "X" was the last capsule pulled from the Callaway reactor vessel. In its response, the applicant stated that Capsule X was the last surveillance capsule removed from the reactor vessel and tested. The staff found the applicant's response acceptable because the applicant confirmed that Capsule X was the last capsule tested. Therefore, the staff's concern described in RAI 4.2.4-1, Part (a), is resolved.

The staff noted that Table 5.0-2 of the Callaway PTLR lists the RG 1.99, Position 2.1 CF for the surveillance plate as 13.9 °C (25 °F) and the adjusted CF for the surveillance weld as 22.2 °C (39.9 °F). However, LRA Table 4.2-4 of the Callaway LRA lists a Position 2.1 CF of 14.2 °C (25.6 °F) for the surveillance plate and 22.7 °C (40.8 °F) for the surveillance weld. Therefore, in RAI 4.2.4-1, Part (b), the staff requested that the applicant explain this discrepancy. In its response the applicant stated that the PTLR CFs for the surveillance materials were calculated using the results of the Capsule X analysis, which is documented in WCAP-15400-NP, whereas the LRA CFs were calculated in WCAP-17168-NP. The WCAP-17168 analysis was performed in support of the 54 EFPY USE and RT_{PTS} calculations listed in LRA Table 4.2-3 and 4.2-4. According to the applicant, WCAP-17168 developed a new neutron fluence model, which incorporates operational information for the period after Capsule X was pulled. The applicant also stated that the source of the discrepancy between the LRA and PTLR CFs is the calculated fluence values that support the Position 2.1 CFs. The small difference in surveillance material CF values documented in the PTLR and the LRA can be attributed to the difference between the neutron fluence models used for each CF calculation. The applicant further stated that both neutron fluence models meet the criteria of RG 1.190 with uncertainty falling within the 20 percent limit specified in the RG. The applicant stated that both neutron fluence models are DORT calculations using the BUGLE 96 cross section library, which is consistent with neutron fluence methodology described in WCAP-14040-A, Revision 4.

The applicant's response to RAI 4.2.4-1, Part (b), also included a table comparing the calculated surveillance capsule fluence values, as determined from the two models. The staff noted that the difference between the two sets of calculated fluence values and the resulting CF values is minor and has no impact on the P-T limit curves for the beltline shell region of the reactor vessel because other materials have higher RT_{NDT} values and thus control the P-T limit curves. The staff found the applicant's response acceptable because the applicant provided an adequate explanation for the discrepancy between the surveillance material CF values listed in the PTLR and the LRA, and the staff agreed with the applicant's explanation that this discrepancy is attributable to minor differences in the fluence inputs used for the CF calculations. The staff found that credible surveillance data was correctly applied for determining the CF values and 28 EFPY adjusted RT_{NDT} values for the reactor vessel plate and weld materials represented in

the Reactor Vessel Materials Surveillance Program. In addition, the staff finds that, since the surveillance material CFs listed in LRA Table 4.2-4 were calculated using neutron fluence valves that incorporate more recent core operating conditions and the values are (slightly) conservative relative to those from the PTLR, the CFs listed in LRA Table 4.2-4 are acceptable. The staff's concern described in RAI 4.2.4-2, Part (b), is resolved.

In RAI 4.2.4-1, Part (c), the staff requested that the applicant identify the calendar year when the current 28 EFPY P-T limit curves are projected to expire. In its response the applicant stated that, as of October 2011, Callaway has experienced 23 EFPY of facility operation. The applicant also stated that Callaway will reach 28 EFPY in April 2017, assuming a plant capacity factor of 90 percent. The staff found the applicant's response acceptable because the applicant identified the calendar year (2017) when the 28 EFPY P-T limits are projected to expire. The staff notes that the TS 5.6.6 require that new P-T limits be established in the PTLR and submitted to the staff before operating beyond this neutron fluence period. Therefore, the staff's concern described in RAI 4.2.4-1, Part (c), is resolved.

10 CFR Part 50, Appendix G, Paragraph IV.A states that:

> [T]he pressure-retaining components of the reactor coolant pressure boundary [RCPB] that are made of ferritic materials must meet the requirements of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code [ASME Code, Section III], supplemented by the additional requirements set forth in [paragraph IV.A.2, "Pressure-Temperature (P-T) Limits and Minimum Temperature Requirements"]…"

Wording provided prior to RAI 4.2.4-1, Part (d), states the following:

> […] 10 CFR Part 50, Appendix G, requires that P-T limits be developed for the ferritic materials in the RV beltline (neutron fluence greater than or equal to 1×10^{17} n/cm^2, E greater than 1 MeV), as well as ferritic materials not in the reactor vessel beltline (neutron fluence less than 1×10^{17} n/cm^2, E greater than 1 MeV). Further, 10 CFR Part 50, Appendix G, requires that all RCPB components must meet the ASME Code Section III, requirements. The relevant ASME Code Section III requirement that will affect the P-T limits is the lowest service temperature requirement for all RCPB components specified in Section III, NB-2332(b).
>
> The current Callaway PTLR and the PTLR methodology described in WCAP-14040-A, Revision 4, address P-T limit curve calculations for only the reactor vessel beltline shell region. P-T limit calculations for ferritic RCPB components that are not reactor vessel beltline shell materials may define P-T curves that are more limiting than those calculated for the reactor vessel beltline shell materials. This may be because of the following factors:
>
> i. Reactor vessel nozzles, penetrations, and other discontinuities have complex geometries that may exhibit significantly higher stresses than those for the RV beltline shell region. These higher stresses can potentially result in more restrictive P-T limits, even if the RT_{NDT} for these components is not as high as that of RV beltline shell materials that have a simpler cylindrical geometry.
> ii. Ferritic RCPB components that are not part of the reactor vessel may have initial RT_{NDT} values, which may define a more restrictive lowest

operating temperature in the P -T limits than those for the reactor vessel beltline shell materials.

Therefore, in RAI 4.2.4-1, Part (d), the staff requested that the applicant describe how the P-T limit curves to be developed for use in the period of extended operation, and the methodology used to develop these curves, will consider all reactor vessel materials (beltline and non-beltline) and the lowest service temperature of all ferritic RCPB materials, consistent with the requirements of 10 CFR Part 50, Appendix G.

In its RAI response, the applicant stated that when the current P-T limits expire at 28 EFPY, new limits will be developed and submitted to the staff in accordance with TS 5.6.6 and 10 CFR Part 50, Appendix G, requirements. The applicant also stated that future P-T limit curves will consider the effects of neutron embrittlement on the adjusted RT_{NDT} for beltline and extended beltline components and the higher stresses in the inlet/outlet nozzle corner region. In addition, the applicant stated that the future P-T limit curves will also consider the effects of the ferritic RCPB components outside the reactor vessel beltline and extended-beltline regions when determining the lowest service temperature. In its response the applicant included LRA Amendment 6, which revised LRA Section 4.2.4 and the corresponding FSAR supplement section provided in LRA Section A3.1.4 to describe how future P-T limit curves will be developed in accordance with the requirements of 10 CFR Part 50, Appendix G, considering all ferritic RCPB components during the period of extended operation.

The staff reviewed the applicant's response to RAI 4.2.4-1, Part (d), including the relevant portions of LRA Amendment 6, and found the response acceptable because the applicant appropriately described how the P-T limit curves to be developed for use in the period of extended operation will consider all reactor vessel materials and the lowest service temperature of all ferritic RCPB materials, consistent with the requirements of 10 CFR Part 50, Appendix G. Specifically, the staff noted that LRA Amendment 6 revisions to LRA Sections 4.2.4 and A3.1.4 ensure that future changes to the P-T limit curves beyond 28 EFPY will consider the following:

- the effects of neutron embrittlement on the adjusted RT_{NDT} values for all reactor vessel locations projected to receive a neutron fluence greater than 1×10^{17} n/cm^2 (E greater than 1.0 MeV)
- the higher stresses in the inside corner region of the reactor vessel inlet and outlet nozzles
- the ferritic RCPB components, which receive a neutron fluence of less than 1×10^{17} n/cm^2 (E greater than 1.0 MeV) when determining the lowest service temperature

Based on a review of the applicant's FSAR, the staff determined that, other than the reactor vessel closure flange region, which is bounded by the minimum temperature requirements specified in Table 1 of 10 CFR Part 50, Appendix G, the reactor vessel inlet/outlet nozzles are the reactor vessel locations for which stress concentration effects are the most significant. Therefore, for the calculation of future P-T limit curves, the staff found that the above LRA revisions provide adequate assurance that future P-T limit curves will be developed such that they are bounding for all ferritic reactor vessel materials and the lowest service temperature of all ferritic RCPB materials, consistent with the requirements of 10 CFR Part 50, Appendix G. The staff's concern described in RAI 4.2.4-1, Part (d) is resolved.

For the reasons discussed above that staff's concern described in RAI 4.2.4-1 is resolved.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of neutron embrittlement on the P-T limits will be adequately managed for the period of extended operation. Additionally, the staff finds that that the applicant's P-T limits analysis meets the acceptance criteria in SRP-LR Section 4.2.2.1.3.3 because the applicant's TS 5.6.6 administrative controls for the PTLR ensure that updated P-T limits for the period of extended operation will be available before entering the period of extended operation.

4.2.4.3 FSAR Supplement

LRA Section A3.1.4 provides the FSAR supplement summarizing the P-T limits TLAA, as revised in LRA Amendment 6. The staff reviewed amended LRA Section A3.1.4 consistent with the review procedures in SRP-LR Section 4.2.3.2, which state that the FSAR supplement is reviewed to verify that the applicant has provided an appropriate summary description of the evaluation of the reactor vessel neutron embrittlement TLAA.

Based on its review of the amended FSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.2.2.2 and is therefore acceptable. Additionally, the staff finds that the applicant provided an adequate summary description of its actions to address the P-T limits for the period of extended operation, 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 provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of neutron embrittlement on the P-T limits will be adequately managed by the TS 5.6.6 PTLR administrative controls for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.5 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 LTOP. The applicant stated that LTOP at Callaway is required by TS 3.4.12 and TS 5.6.6, and is provided by the cold overpressure mitigation system (COMS), which opens the pressurizer PORVs at a setpoint calculated to prevent violation of the P-T limits. COMS setpoints are established in the PTLR.

The applicant stated that, since the COMS setpoints are based on the P-T limits, which are a TLAA, the COMS setpoints are also a TLAA, and these LTOP analyses do not depend on any other time-dependent values beyond the P-T limits and the adjusted RT_{NDT} values at the critical locations. The applicant stated that changes to the RCS P-T limit curves also require an evaluation of the COMS enable temperature and PORV pressure setpoints, and supporting safety analyses, based on the methodology used to determine the COMS PORV setpoints, WCAP-14040-NP-A and ASME Code Case (CC) N-514, "Low Temperature Overpressure Protection, Section XI, Division 1." The applicant also stated that the COMS setpoints are established in the PTLR and are managed consistent with the P-T limits.

The applicant dispositioned the TLAA for LTOP in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of neutron embrittlement on the COMS enable temperature and pressure setpoints will be adequately managed by the PTLR process (as established in TS 5.6.6 administrative controls) for the period of extended operation.

4.2.5.2 Staff Evaluation

The staff reviewed the applicant's TLAA for LTOP and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with the review procedures in SRP-LR Section 4.2.3.1.3.3, which state that updated P-T limits for the period of extended operation must be available before entering the period of extended operation. SRP-LR Section 4.2.3.1.3.3 also states that either the 10 CFR 50.90 process for P-T limits located in the TS LCOs or the TS administrative controls process for P-T limits contained in PTLRs can be considered adequate AMPs within the scope of 10 CFR 54.21(c)(1)(iii), such that P-T limits will be appropriately maintained through the period of extended operation. The staff noted that, although SRP-LR Section 4.2.3.1.3.3 explicitly addresses P-T limit TLAA reviews, this SRP-LR section is also the appropriate review standard for the LTOP TLAA, as discussed below.

LTOP at Callaway is provided by the COMS. The COMS opens the pressurizer PORVs at a setpoint calculated to prevent violation of the P-T limits. At Callaway, P-T limits and COMS setpoints are established in the PTLR, and the COMS setpoints are based on the P-T limits. In LRA Section 4.2.5, the applicant proposed to manage the COMS setpoints using the PTLR process, which is administratively controlled in accordance with Callaway TS 5.6.6 requirements. Therefore SRP-LR Section 4.2.3.1.3.3 is the appropriate review standard for the applicant's LTOP TLAA because the applicant has proposed to manage the COMS setpoints for the period of extended operation in the same manner as the P-T limits.

The PTLR process for Callaway, as established in TS 5.6.6, requires that the COMS setpoints be developed using the staff-approved methodology of WCAP-14040-A, Revision 4.
TS LCO 3.4.12 specifies that the COMS shall be operable for the following modes of reactor operation:

- MODE 4 – hot shutdown, with any RCS loop cold leg temperature less than or equal to than 135 °C (275 °F)
- MODE 5 – cold shutdown
- MODE 6 – refueling, with the reactor vessel head installed

LCO 3.4.12 requires that pressure relief capabilities be provided by the PORVs, within the COMS pressure setpoints, as established in the PTLR or alternatively, by two RHR system suction relief valves with lift setpoints greater than or equal to 436.5 psig and less than or equal to 463.5 psig. The RHR suction relief valve lift setpoints are established directly in LCO 3.4.12. The staff confirmed that the COMS PORV setpoints established in the current Callaway PTLR and the RHR suction relief valve lift setpoints in the LCO limit the pressure in the reactor vessel to less than the maximum pressure allowed by the current P-T limit curves. Future COMS setpoints will be developed using the methodologies of WCAP-14040-A, Revision 4, and ASME Code Case N-514 as stated in LRA Section 4.2.5.

ASME Code Section XI Article G-2215, specifies pressure and temperature conditions for LTOP systems to ensure protection against RCPB failure during reactor startup and shutdown operations. Article G-2215 states that LTOP systems shall be effective at RCS temperatures less than 93 °C (200 °F) or at RCS temperatures corresponding to a reactor vessel metal temperature less than the limiting RT_{NDT} value + [27.8 °C] 50 °F, whichever is greater. Based on the 54 EFPY adjusted RT_{NDT} value for the limiting reactor vessel beltline material (49 °C or 120 °F at the clad/base metal interface), the staff confirmed that the current COMS enable

temperature of 135 °C (275 °F) is bounded by the ASME Code Section XI requirements for LTOP enable temperatures.

The staff noted that implementation of the WCAP-14040-A, Revision 4 methodology, as specified in TS 5.6.6, requires that changes to RCS P-T limits include an evaluation of the COMS enable temperature, PORV pressure setpoints, and supporting safety analyses. The staff noted that the methodology used to determine the COMS PORV setpoints conforms to WCAP-14040-A, Revision 4.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of neutron embrittlement on the plant's LTOP capability will be adequately managed for the period of extended operation. Additionally, the staff finds that the applicant's LTOP analysis meets the acceptance criteria in SRP-LR Section 4.2.2.1.3.3 because the applicant's TS 5.6.6 administrative controls for the PTLR ensure that updated COMS setpoints for the period of extended operation will be available before entering the period of extended operation.

4.2.5.3 FSAR Supplement

LRA Section A3.1.5 provides the FSAR 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 FSAR supplement is reviewed to verify that the applicant has provided an appropriate summary description of the evaluation of the reactor vessel neutron embrittlement TLAA.

Based on its review of the FSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.2.2.2 and is therefore acceptable. Additionally, the staff finds that the applicant provided an adequate summary description of its actions to address the LTOP system for the period of extended operation, 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 provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of neutron embrittlement on the LTOP capability will be adequately managed by the TS 5.6.6 PTLR administrative controls for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3 Metal Fatigue

4.3.1 Fatigue Monitoring Program

LRA Section 4.3.1 states that ASME III Class 1 design specifications define a set of static and transient load conditions for which components are to be designed. The fatigue analyses are based on a specified number of occurrences of each transient rather than the design or licensed life.

The Fatigue Monitoring Program manages crack initiation caused by the specified transient conditions by periodically counting and evaluating transients consistent with GALL Report AMP X.M1 and is required by Callaway TS 5.5.5, "Component Cyclic or Transient Limit." The program will require periodic reviews of the plant instrumentation and operator logs to ensure that the critical thermal and pressure transients have not exceeded the design transient severity

or analyzed number and to ensure that usage factors will not exceed the allowable value of 1.0 without corrective actions.

LRA Table 4.3-2, “Transient Accumulations and Projections,” lists the transients monitored by the Fatigue Monitoring Program, which were identified through a review of the design and licensing analyses. These identified transients will be reconciled with the transients identified in FSAR Table 3.9(N)-1 SP in accordance with 10 CFR 54.29.

4.3.1.1 Fatigue Monitoring Methods

4.3.1.1.1 Summary of Technical Information in the Application

LRA Section 4.3.1.1 states the Fatigue Monitoring Program will include both manual cycle counting of certain transients along with automatic cycle counting of selected transients using monitoring software. In addition, the program monitors transient pressure and thermal conditions to calculate the actual fatigue usage for specified fatigue critical locations. Monitored locations will include locations identified by the evaluation of ASME Code Section III fatigue analyses; the sample locations for a newer vintage Westinghouse plant listed in NUREG/CR-6260, “Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components,” February 1995; and plant-specific bounding environmentally-assisted fatigue (EAF) locations. The program also accounts for the effects of the reactor coolant environment on fatigue usage where applicable.

The program will track the occurrences of plant transients listed in LRA Table 4.3-2 using cycle counting, and monitors the cumulative usage factors (CUFs) at the components listed in LRA Table 4.3-1 using either cycle-based fatigue (CBF) or stress-based fatigue (SBF). The LRA provides the details of the CBF and SBF monitoring methods.

The LRA also describes the charging nozzle SBF benchmarking evaluation performed to address Regulatory Issue Summary (RIS) 2008-30. RIS 2008-30 discusses the staff concerns about the use of a single-stress term used in SBF algorithms and only recommends that it be demonstrated that the simplification of the use of less than the six-stress tensors produces a conservative result. Thus, the applicant performed a benchmark evaluation to demonstrate that the charging nozzle SBF algorithm produces a conservative CUF as compared to an independent ASME Code Section III, Division 1, Subsection NB, Subarticle NB- 3200 fatigue calculation of the same component. The LRA provided the details of the benchmarking performed for the charging nozzle SBF algorithm, which indicates that the bulk of the difference is due to the use of Green’s Functions (influence functions, based on constant material properties) and is not attributable to the use of a single stress term. Furthermore, the applicant determined that the concerns expressed by the staff in RIS 2008-30 are addressed and eliminated for the charging nozzles.

4.3.1.1.2 Staff Evaluation

LRA Section 4.3.1.1 discusses the monitoring methods of the Fatigue Monitoring Program that will be used to manage metal fatigue of various components discussed in LRA Section 4.3. The staff noted that the monitoring methods of the Fatigue Monitoring Program include cycle counting, cycle-based fatigue monitoring and stress-based fatigue monitoring. The staff’s evaluation of the acceptability of these monitoring methods to manage metal fatigue is documented in SER Section 3.0.3.2.22.

LRA Section 4.3.1.1 states that a benchmark was performed to demonstrate that the charging nozzle SBF algorithm produces a conservative CUF when compared to an ASME Code Section III, Subarticle NB-3200 fatigue calculation of the same component. The benchmarking consisted of inputting the temperature, pressure, and flow rate time histories for the most severe transient pairs into the SBF algorithms. These time histories, which are the same as those assumed in the NB-3200 fatigue calculation, constitute about 88 percent of the NB-3200 CUF. The LRA states that a comparison demonstrated that the CUF for those transient pairs as computed by the SBF algorithms is more conservative than the CUF calculated with all transient pairs as computed using the detailed NB-3200 methodology.

The staff noted that the LRA did not provide sufficient detail to support its statement that the single-stress component SBF is more conservative than the NB-3200 calculation. Since the LRA did not identify or compare the results between the single stress component SBF and NB-3200 calculations, the staff was not able to verify the adequacy of the applicant's calculation to support the use of single stress component SBF for the charging nozzle.

By letter dated September 6, 2012, the staff issued RAI 4.3-8 requesting the applicant to identify those most severe transient pairs that "constitute about 88% of the NB-3200 CUF" and provide the associated CUF contribution for these pairs. In addition, the applicant was requested to identify the CUF contributions (both in SBF and NB-3200 calculations) for the two transients, described above. Finally the applicant was requested to justify that the results calculated from the single-stress component SBF is conservative compared to the NB-3200 for the charging nozzle.

In its response dated October 11, 2012, the applicant provided the transient pairs that "constitute about 88% of the NB-3200 CUF" of 0.164 for the charging nozzles and stated that it was the result of an elastic-plastic fatigue analysis performed to support license renewal. The applicant also provided the CUF contributions (both in SBF and NB-3200 calculations) for the two transients that the SBF algorithms calculated stress ranges approximately one to two percent less than the NB-3200 analysis. The staff noted that these two transient pairs were the "charging decrease/letdown increase" pair with a CUF contribution of 0.036 and "charging increase/ letdown increase" pair with a CUF contribution of 0.008. The applicant also explained that the SBF algorithm CUF was 0.172, which is approximately 5 percent more conservative than the NB-3200 CUF of 0.164. The staff noted that the overall results demonstrated that the applicant's use of its SBF algorithm would produce a higher CUF value when compared to an NB-3200 analysis. The staff noted that a higher calculated CUF value is considered conservative because there is additional margin that was not removed from the calculation results. Based on the data and results provided in the RAI response, the staff was able to confirm that the CUF value calculated with the SBF algorithm for the charging nozzles are greater than the CUF value of an NB-3200 analysis. Thus, the staff finds the applicant's response acceptable. The staff's concern described in RAI 4.3-8 is resolved.

The staff noted that the applicant's benchmark evaluation demonstrated that the issue identified in RIS 2008-30 is not applicable to its charging nozzle SBF calculation. Thus, the staff finds it reasonable that the applicant implement SBF monitoring for the charging nozzles as indicated in LRA Table 4.3-1. The staff noted that the SBF monitoring method computes a "real-time" stress history for a given component from data that is collected by plant instruments to calculate transient pressure and temperature, and the corresponding stress history at the critical location. The use of actual plant data, such as local pressure and thermal conditions, to calculate actual fatigue usage is consistent with the "parameters monitored/inspected" program element of

GALL Report AMP X.M1 for more "detailed monitoring." The staff's evaluation of the applicant's Fatigue Monitoring Program is documented in the SER Section 3.0.3.2.22.

4.3.1.1.3 FSAR Supplement

LRA Sections A2.1 and A3.2 provide the FSAR supplement summarizing the applicant's basis of its fatigue analyses and describing its Fatigue Monitoring 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 4.3.3.2. The procedures state that the reviewer should confirm that the applicant has provided information to be included in the FSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the FSAR supplement, the staff finds that 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 for its Fatigue Monitoring Program to monitor the numbers of transients actually experienced, as required by 10 CFR 54.21(d).

4.3.1.1.4 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 Fatigue Monitoring Program. The program ensures that corrective actions are taken before exceeding the design limit during the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the monitoring bases of transients and design cycles, as required by 10 CFR 54.21(d).

4.3.1.2 Projected Status of Monitored Transients

4.3.1.2.1 Summary of Technical Information in the Application

Cycle Count Baselining. LRA Section 4.3.1.2 states that a review of the operating history was performed under a 10 CFR 50 Appendix B Program in order to baseline the transient event count in the Fatigue Monitoring Program from initial startup (1983) to January 31, 2011. The baseline was performed covering two periods of operation. For Period 1, which covers plant startup through May 10, 1995, the manual records of the current program were used to re-create the event history for the plant. For Period 2, which covers May 11, 1995 through January 31, 2011, fatigue monitoring software was used to review plant instrument data to identify transient occurrences. If the plant instrumentation was unavailable for Period 2, then the manual plant records were used.

Cycle Count Projection Method. LRA Section 4.3.1.2 states that the baseline cycle counting results were projected to a 60-year operating life based on the actual accumulation history since the start of plant life. The cycle projections are based on (1) a long-term rate of cycle accumulation, based on the entire history, and (2) a short-term rate of cycle accumulation. The LRA describes the cycle projection methodology and states that, by weighting the short-term operation more heavily than the long-term operation, more weight is given to the recent plant history in the future projection calculations. The assumption is that recent plant operating history is generally a better predictor of future plant operation than the early operating history. In addition, these projections are intended to be a best estimate of the actual cycles expected and do not represent a revision of the design basis. The purpose is to demonstrate that the

40-year design numbers of transients are reasonable for 60 years and future cycle count projections will be based on the actual accumulation history over the analysis period.

The projected cycle counts for 60 years of operation are provided in LRA Table 4.3-2.

4.3.1.2.2 Staff Evaluation

The staff reviewed LRA Section 4.3.1.2 to confirm that the transients that are significant fatigue contributors are monitored to ensure that the applicant's fatigue evaluations remain valid and that the methodology for determining the baseline cycle counts is appropriate. The staff also reviewed the methodology used by the applicant to obtain the 60-year cycle projections. The staff's evaluation of the applicant's Fatigue Monitoring Program, which is used to cycle count these transients, is documented in the SER Section 3.0.3.2.22.

LRA Table 4.3-2 describes Transient 1b as "Plant Cooldown at 100 ^{o}F/hr, Pressurizer Cooldown at 200 ^{o}F/hr" and indicates that there were 29 occurrences of Transient 1b between 1983 and 2011. FSAR Table 3.9(N)-1A SP indicates that the "plant cooldown cycle at less than 100 ^{o}F/hr" is defined as "cooldown cycle T_{ave} from ≥ 550 ^{o}F to ≤ 200 ^{o}F" and that the "pressurizer cooldown cycle at less than 200 ^{o}F/hr" is defined as "pressurizer cooldown cycle temperature from ≥650 ^{o}F to ≤ 200 ^{o}F."

Based on these descriptions in the LRA and FSAR, it is not clear to the staff why the plant cooldown and pressurizer cooldown cycles are grouped together as a single transient (Transient 1b) in LRA Table 4.3-2 and whether the two components of Transient 1b should be considered separately based on the definition in the FSAR SP.

By letter dated September 6, 2012, the staff issued RAI 4.3-1 requesting that the applicant provide the basis for combining these two transients when they are being monitored by the Fatigue Monitoring Program. In addition, with respect to the baseline value of 29 occurrences in LRA Table 4.3-2, the applicant was requested to clarify whether the two transients have been monitored separately or together since the beginning of power operations (considering that manual records and fatigue monitoring software have been used).

In its response dated October 11, 2012, the applicant clarified that the Fatigue Monitoring Program combined the monitoring of the plant cooldown and pressurizer cooldown. The staff noted that although the Fatigue Monitoring Program combined the monitoring of these two transients, the applicant confirmed that these transients are counted separately and the cycle count for plant cooldown, pressurizer cooldown, and Transient 1b increment by one cycle when the plant is shut down. The applicant confirmed that the number of plant cooldown and pressurizer cooldown transients were baselined separately since the beginning of power operation.

The staff finds the applicant response acceptable because (1) since the plant cooldown and pressurizer cooldown transients are considered separately and counted independently, the staff finds it appropriate that the applicant performed baseline cycle counts of these two transient separately; and (2) based on the applicant's clarifications, the staff finds that the Fatigue Monitoring Program is capable of cycle counting Transient 1b and ensuring that the number of actual occurrences of this transient does not exceed the number used in fatigue analyses; otherwise corrective actions will be taken. Therefore, the staff's concern described in RAI 4.3-1 is resolved.

LRA Section 4.3.1.2 states the baseline cycle counting results were projected to a 60-year operating life based on the actual accumulation history since the start of plant life. In addition, a rate of future cycle accumulation is computed for each transient and the cycle projections are based on a long-term rate and a short-term rate of cycle accumulation. These accumulation rates are then combined based on a weighting factor of one for the long-term rate and three for the short–term rate. The staff noted that since the applicant used the 60-year transient projections to support the disposition of the TLAAs evaluated in LRA Sections 4.7.2 and 4.7.7, additional information is required to determine whether the long-term and short-term weighting factors and the associated transient occurrences for these weighting factors used in the projection methodology is appropriate and conservative.

By letter dated September 6, 2012, the staff issued RAI 4.3-2, Part (a), requesting the applicant to identify the transients in LRA Table 4.3-2 in which the long-term and short term weighting factors are applicable and provide the short-term and long-term occurrence rate for each transient. In addition, RAI 4.3-2, Part (b), the applicant was requested to describe and justify as conservative any "alternative" 60-year projection methodology, other than the one discussed in LRA Section 4.3.1.2.

In response to Part (a) to RAI 4.3-2, dated October 11, 2012, the applicant provided the short-term and long-term weighting factors. However, the applicant did not provide short-term and long-term occurrences (i.e., short-term average rate of accumulation and total average rate of accumulation, respectively) of each transient as requested in Part (a) of RAI 4.3-2.

By letter dated November 21, 2012, the staff issued RAI 4.3-2a requesting that the applicant provide the short-term average rate of accumulation and total average rate of accumulation for each transient listed in LRA Table 4.3-2 that supports the calculation of the 60-year projections.

In its response to RAI 4.3-2a dated December 13, 2012, the applicant provided a table (Table 1) with the short-term average rate and total average rate of accumulation for each transient listed in LRA Table 4.3-2. The applicant stated there were differences between LRA Table 4.3-2 and the table provided in the RAI response; thus, in order to be consistent, LRA Table 4.3-2 was revised to be consistent with Table 1 of the RAI response. The applicant described the differences between the tables and stated that the changes did not affect any TLAA dispositions. The staff reviewed the revisions to LRA Table 4.3-2 and confirmed that the TLAA dispositions that rely on the 60-year projections (i.e. 10 CFR 54.21(c)(1)(i) and (ii)) in LRA Sections 4.3 and 4.7 were not affected. The staff also noted that the revisions do not affect the applicant's ability to manage EAF calculations, which are based on the 60-year cycle projections, because the Fatigue Monitoring Program incorporates preemptive cycle action limits to initiate corrective actions. The staff's review of these cycle count action limits are documented in SER Section 3.0.3.2.22.

The staff noted the projections for transients used in TLAAs discussed in LRA Sections 4.7.2 and 4.7.7 do not exceed 50 percent of the design number of cycles. The staff also noted that there is margin between the design cycle limits and the expected number of cycles at 60 years to account for unanticipated transient occurrence. Therefore, the staff finds that this margin could be used to support a conclusion that these TLAAs could be dispositioned in accordance with 10 CFR 54.21(c)(1)(i). The staff's evaluations of the TLAAs for in-service flaw analyses that demonstrate structural integrity for 40 years are documented in SER Section 4.7.2.2. In addition, the staff's evaluations of the TLAAs for fatigue crack growth assessment in support of a fracture mechanics analysis for the LBB elimination of dynamic effects of piping failures are documented in SER Section 4.7.7.2.

The staff reviewed Table 1 of the RAI response and noted that there is margin between the 60-year projected cycles and the design cycle limit; thus, the staff determined that it is reasonable that the 60-year projections are not solely based on data from the entire history of plant operation because recent operating practices are expected to be more representative of how the plant will operate in the future. Furthermore, the staff finds the 60-year cycle projections reasonable because the Fatigue Monitoring Program ensures that actual plant experience will remain bounded by the thermal and pressure transient numbers and severities analyzed in the design calculations, or that corrective actions will implemented to maintain the design and license basis of the components.

The staff finds the applicant's response to Part (a) to RAI 4.3-2 and RAI 4.3-2a acceptable because (1) the applicant provided the details of its 60-year projection methodology based on short-term and long-term operational history; (2) the projections provide a reasonable outlook at the number of cycles expected to occur after 60-years of operation, as described above; and (3) the applicant manages transient cycle counts with its Fatigue Monitoring Program to ensure design limits are not exceeded. The staff's concerns described in Part (a) to RAI 4.3-2 and RAI 4.3-2a are resolved.

In response to Part (b) to RAI 4.3-2, dated October 11, 2012, the applicant provided a list of transients that used an "alternative" 60-year projection methodology. The staff's review of each "alternative" methodology is documented below.
The applicant stated that the 60-year projection is set equal to the baseline for "Normal Transient #13, Turbine roll test," "Test Transient #1, Primary side hydrostatic test," and "Test Transient #2, Secondary side hydrostatic test," because these tests were performed during initial startup and no more tests are expected. The staff finds it reasonable that the 60-year projections were set equal to the baseline count because these are transients associated with the initial plant operation and are not associated with the normal, current, or future operation of the applicant's site.

The applicant stated that the 60-year projection is set equal to the baseline for "Upset Transient #2, Loss of Power (with natural circulation in the RCS)" and "Upset Transient #8, Inadvertent safety injection actuation," because this is the value analyzed in the EAF calculations and is further justified in LRA Section 4.3.4. The staff noted that LRA Section 4.3.4 states that, even though the numbers of "inadvertent safety injection" and "loss of power" events to-date were used in fatigue analyses, the affected location is monitored with CBF. The staff finds acceptable that the 60-year projection is set equal to the baseline for these two transients because: (1) there is margin between the baseline cycle count and the design limiting value, and (2) the affected locations are managed with CBF that will determine, with each transient occurrence, the incremental contribution to the CUF and ensure that the design limit of 1.0 is not exceeded during the period of extended operation.

In its response, the applicant provided 10 upset transients, one test transient, and six auxiliary transients in which the projected number of events was set equal to one event because there have been no historical events recorded on which to base an accumulation rate. The staff finds it reasonable that these 17 transients were projected to occur once through the period of extended operation because after 27 years of operation there have been no recorded occurrences of these transients. In addition, there is margin between the baseline cycle count and the design limiting value, and the Fatigue Monitoring Program monitors these transients to ensure the design limit is not exceeded before corrective actions are taken to assess any impact.

The applicant stated that for "Normal Transient #7a/b, Loop out of service, Normal loop shutdown/startup," the 60-year projection is zero because its site is not licensed for N-1 loop operation. The staff reviewed the applicant's FSAR SP and noted on page 450-17 that the site does not operate with a loop out of service. The staff finds it acceptable that this transient is not projected to occur because the applicant's current licensing basis does not permit operation with a loop out of service.

The applicant stated that the maneuver associated with "Normal Transient #11, Reduced temperature return to power," is not used because Callaway does not load follow. The staff finds it acceptable that this transient is not projected to occur since this transient is associated with load-following operation and the applicant operates its plant as base-loaded.

The applicant stated that for "Auxiliary Transient #28, Excess letdown heat exchanger operation," the 60-year projection is based on a linear projection of the available data and is further explained in LRA Section 4.3.8. The staff's evaluation of this projection is documented in SER Section 4.3.8.2. Based on the aforementioned evaluation of the applicant's response regarding alternative 60-year projection methodologies, the staff concerns identified in Part (b) to RAI 4.3-2 are resolved.

LRA Table 4.3-2 describes that for Normal Transients 16a and 16b, the baseline results were judged to be conservative based on a review of instrumentation data available from 2000 to 2011. However, it is not clear to the staff whether the baseline numbers of 56 and 12, for Normal Transients 16a and 16b, respectively, were the results of a review of instrumentation data available from 2000 to 2011 or whether they incorporated a backward-projection to include the years from 1983 to 2011. In addition, the applicant did not provide the technical basis for why using the data from 2000 to 2011 was conservative and whether the 1:3 ratio for long-term to short-term weighting factor was used to calculate the 60-year projection for this transient.

By letter dated September 6, 2012, the staff issued RAI 4.3-3, Part (a) requesting the applicant to provide the number of occurrences for Normal Transients 16a and 16b from 2000-2011 and the calculation performed to obtain the baseline values for 56 and 12 in LRA Table 4.3-2. The applicant was further requested to justify that the data from 2000-2011 is conservative to represent the occurrences of these transients between 1983 and 2011. In Part (b) of RAI 4.3-3, the applicant was requested to provide and justify the short-term and long-term weighting factors used to calculate the 60-year projection and the associated transient occurrences for these weighting factors.

In response to Part (a) to RAI 4.3-3 dated October 11, 2012, the applicant stated it experienced 22 events of Normal Transient 16a, "Feedwater heaters out of service: One heater out of service," between 2000 and 2011. In its response to Part (b) of RAI 4.3-3, the applicant stated that in the past 9 years there have been 12 events of Normal Transient 16a and that a weighting factor of 1 for the long term and 3 for the short term were used and that the short-term period consists of the preceding 9 years.

Based on the information provided, the staff noted that there were approximately 10 events of Normal Transient 16a that occurred from 2000 through 2002. Since LRA Table 4.3-2 states the 60-year projection is 106 cycles and the design limiting value is 120 cycles, it is not clear to the staff whether using the occurrences from preceding 9 years is conservative and represents the future trend for Normal Transient 16a, considering the short-term occurrence would be 22 if a short-term period of 11 years was used.

By letter dated November 21, 2012, the staff issued RAI 4.3-3a requesting the applicant to provide the annual occurrence for Normal Transient 16a since the plant startup to 2011 to show the trend of this transient. The applicant also was requested to justify that the 60-year projection, for Normal Transient 16a, using a short-term period of the preceding 9 years (2002-2011) is conservative considering that 10 events occurred from 2000 through 2001.

In its response to RAI 4.3-3a dated December 13, 2012, the applicant provided the occurrences for Normal Transient 16a since plant startup until 2011. The applicant explained that the reason for the high frequency of Normal Transient 16a between 2000 and 2001 is due to the spurious isolation of the 3B low pressure heater due to a Hi-Hi level alarm. In response to these conditions the applicant replaced the stage 3 feedwater heaters during Spring 2001. The staff noted that the replacement feedwater heater did not completely resolve the condition described above, but it did lower the accumulation rate over the next 10 years.

The applicant confirmed that Normal Transient 16a is not used in the analyses discussed in LRA Sections 4.7.2 and 4.7.7. The staff noted that the analyses discussed in LRA Sections 4.7.2 and 4.7.7 were dispositioned in accordance with 10 CFR54.21(c)(1)(i), which could be affected by the use of a non-conservative 60-year projection. However, since these analyses do not use this transient as an input, the staff determined that the 60-year projection methodology for this transient does not impact the TLAA disposition. In addition, since the applicant uses it Fatigue Monitoring Program to track the occurrences of Normal Transient 16a, the staff finds it reasonable that any increase in accumulation rate of this transient will be identified and action limits will prevent the design limit from being exceeded. The staff noted that establishing action limits provides the applicant sufficient time for activities such as resource utilization and planning future activities to ensure that corrective actions will be complete prior to the design limits from being exceeded.

The staff finds the applicant's response to RAI 4.3-3 and RAI 4.3-3a acceptable because Normal Transient 16a is monitored by the Fatigue Monitoring Program, which will prevent the design limit of 120 cycles from being exceeded, and there are no TLAA dispositions that are affected by the 60-year projection of Normal Transient 16a.

LRA Table 4.3-2 indicates that for Normal Transient 5b, "Steady state fluctuations, Random fluctuations," the number of cycles is beyond the endurance limit of the fatigue curve and, therefore, this transient does not need to be counted. The staff noted that the endurance limit of the fatigue curve is typically referred to as the stress level below which it results in an infinite number of allowable cycles. Based on the information in the LRA, it may be interpreted that the endurance limit is based upon a certain number of cycles. Thus, the applicant has not explained why the transient does not need to be counted when the number of cycles is greater than 10^6.

By letter dated September 6, 2012, the staff issued RAI 4.3-4 requesting the applicant clarify and explain the statement that "the number of cycles is beyond endurance limit of the fatigue curve" and provide the basis for not counting this transient when the number of cycles is greater than 10^6.

In its response dated October 11, 2012, the applicant revised the "Comments" for Normal Transient 5b in LRA Table 4.3-2 and clarified that the occurrence of this transient does not result in the accumulation of fatigue usage. The applicant also stated that the temperature and pressure variations caused by this transit are very small and that the resulting stress intensity ranges do not result in any contribution to fatigue usage.

The staff finds it reasonable that, if the stress caused by Normal Transient 5b is less than the alternating stress intensity (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 cyclic stress that would result in metal fatigue. Therefore, the staff finds that this transient does not need to be monitored by the Fatigue Monitoring Program during the period of extended operation. The staff's concern described in RAI 4.3-4 is resolved.

LRA Table 4.3-2 indicates that there are 29 occurrences of the plant heatup transient, 29 occurrences of the plant cooldown transient, 66 occurrences of the reactor trip transient, 2 occurrences of the inadvertent RCS depressurization transient, and 1 occurrence of the loss of power transient. Based on the baseline cycle occurrence data in LRA Table 4.3-2, it is not clear to the staff how there are an equal number of plant heatup and cooldown transients when considering there have been occurrences of reactor trip, inadvertent RCS depressurization, and loss of power transients. Thus, it is not clear to the staff whether there is a plant heatup recorded after each occurrence of the reactor trip, RCS depressurization, or loss of power.

By letter dated September 6, 2012, the staff issued RAI 4.3-5 requesting the applicant to provide the basis that there are an equal number of plant heatup and cooldown transients when considering there have been occurrences of reactor trip, inadvertent RCS depressurization, and loss of power transient.

In its response dated October 11, 2012, the applicant clarified that a plant cooldown is counted independently from the reactor trip, inadvertent RCS depressurization, and loss of power transients. Since these transients are counted independently, the staff noted that the occurrence of one of these upset transients does not preclude a plant cooldown event from being counted. Furthermore, the applicant explained that the occurrence of an inadvertent RCS depressurization, loss of power, and reactor trip transient does not always result in a plant cooldown. Following one of these upset transients, however, if there is a plant cooldown, there would be a subsequent heatup event to return the unit to power. The applicant clarified that all plant cooldowns and plant heatups are counted separately, regardless of whether they follow a reactor trip or any other event. The staff noted that since the fatigue analyses incorporated these transients separately, it is appropriate that the number of cycles are counted independent of one another to ensure that the assumptions in these analyses are not exceeded.

Based on the applicant's clarifications, the staff finds that the Fatigue Monitoring Program is capable of counting the number of occurrences for transients, such as the plant heatup, plant cooldown reactor trip, inadvertent RCS depressurization, and loss of power, incorporated into fatigue analyses to ensure that the number of actual transient occurrences does not exceed the number used in any fatigue analyses. The staff's evaluation of the Fatigue Monitoring Program is documented in SER Section 3.0.3.2.22. Therefore, the staff's concern described in RAI 4.3-5 is resolved.

Based on its review, the staff finds the applicant demonstrated that it has an appropriate baseline for monitored transients and that it monitors all transients that cause cyclic strains which are significant contributors to the fatigue usage factor with its Fatigue Monitoring Program, such that corrective actions are taken prior to exceeding the design limit. Even though the applicant's projection methodology provides a reasonable outlook of the number of cycles after 60 years of operation, which are less than the design cycle limits, the staff finds the applicant's Fatigue Monitoring Program ensures that such that the effects of aging due to metal fatigue will be adequately managed for the period of extended operation.

4.3.1.2.3 FSAR Supplement

LRA Sections A2.1, as amended by letter dated June 5, 2012, and A3.2 provide the FSAR supplement summarizing the applicant's basis of its fatigue analyses and describing its Fatigue Monitoring 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 4.3.3.2. The procedures state that the reviewer should confirm that the applicant has provided information to be included in the FSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.
Based on its review of the FSAR supplement, the staff finds that 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 for its Fatigue Monitoring Program to monitor the numbers of transients actually experienced, as required by 10 CFR 54.21(d).

4.3.1.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant has an appropriate baseline for all transients and that these transients will be monitored by the Fatigue Monitoring Program Program such that the effects of aging due to fatigue on the intended functions will be adequately managed for the period of extended operation. In addition, the staff concludes that the applicant's projection methodology provides a representative expectation of the number of cycles after 60 years of operation, which are below the design cycle limits, and the Fatigue Monitoring Program ensures corrective actions are taken prior to exceeding the design limit during the period of extended operation.

4.3.2 ASME Section III Class I Fatigue Analysis of Vessels, Piping, and Components

4.3.2.A Summary of Technical Information

LRA Section 4.3.2 states that fatigue analyses are performed for ASME Code Section III, Division 1, Class 1 components per the ASME Code Section III, paragraph NB-3222.4(e).
A detailed fatigue evaluation is not required if components conform to the waiver of fatigue requirements, ASME Code paragraph NB-3222.4(d). The LRA states that these fatigue analyses and fatigue waivers depend on the numbers of anticipated transients over the life of the plant and, therefore, constitutes TLAAs.
The following lists all vessels, pumps, and components subject to Class 1 fatigue analyses.

- reactor pressure vessel (RPV), nozzles, head, head adapter plugs, and studs
- control rod drive mechanisms (CRDMs) and core exit thermocouple nozzle assembly (CETNAs) (the CRDMs were shown to satisfy the fatigue waiver requirements)
- reactor coolant pumps (RCP) (the RCP casing, thermal barrier assembly, seal housing, and auxiliary nozzles were shown to satisfy the fatigue waiver requirements)
- pressurizer and pressurizer nozzles
- steam generators, and feedwater nozzles (no fatigue analysis is required for the Class 2 secondary side of the steam generator; however, the entire pressure boundary of the replacement steam generators is constructed in accordance with ASME Code Section III Class 1 requirements)

- ASME III Class 1 valves
- ASME III Class 1 piping and piping nozzles

The fatigue analyses for the components listed in LRA Table 4.3-3 and the fatigue waiver evaluations were performed using the transients listed in LRA Table 4.3-2. These analyses and waivers will remain applicable as long as the numbers of specified design transients are not exceeded. Thus, the Fatigue Monitoring Program will track the numbers of events and transient severities. The applicant stated that LRA Sections 4.3.2.1 through 4.3.2.4 include topics that required additional consideration when evaluating the ability of the Fatigue Monitoring Program to manage fatigue and fatigue analyses, which were not dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

The applicant dispositioned the TLAAs for the vessels, pumps, and components subject to Class 1 fatigue analyses, as listed above, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of metal fatigue on the intended functions will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

4.3.2.B Staff Evaluation

The staff reviewed LRA Section 4.3.2 and the TLAAs for the vessels, piping, and components subject to Class 1 analyses, except those discussed in LRA Sections 4.3.2.1 through 4.3.2.4, to verify, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of fatigue will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

The staff reviewed the applicant's TLAAs for the vessels, piping, and components subject to ASME Section III Class 1 analyses, except those discussed in LRA Sections 4.3.2.1 through 4.3.2.4, 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 verify the appropriateness of the applicant's program for monitoring and tracking the number of critical thermal and pressure transients for the selected RCS components.

The staff reviewed LRA Table 4.3-3, which provides the CUF values for the components that have ASME Class 1 fatigue analyses which will be managed by the Fatigue Monitoring Program, and noted that the CUF values are less than the Code design limit of 1.0. The staff determined that the program includes three monitoring methods (cycle counting, cycle-based fatigue monitoring, and stress-based fatigue monitoring) that are capable of managing metal fatigue during the period of extended operation. The staff also determined that the use of these three monitoring methods progressively provide a more refined monitoring approach to manage metal fatigue to ensure that the applicable allowable design limits are not exceeded and fatigue waivers remain valid. The staff determined that these characteristics of the applicant's Fatigue Monitoring Program are consistent with GALL Report AMP X.M1. The staff's evaluation of the Fatigue Monitoring Program is documented in SER Section 3.0.3.2.22.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging related to metal fatigue of the vessels, pumps, and components subject to Class 1 fatigue analyses, except those discussed in LRA Sections 4.3.2.1 through 4.3.2.4, 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 is crediting its Fatigue Monitoring Program, which the staff determined in SER Section 3.0.3.2.22 is consistent with GALL Report AMP X.M1, to manage metal fatigue to ensure that the allowable design limits on fatigue usage are not exceeded during the period of

extended operation; otherwise, the applicant will take corrective actions in accordance with its program.

4.3.2.C FSAR Supplement

LRA Section A3.2.1 provides the FSAR supplement summarizing the TLAA for the vessels, piping, and components subject to Class 1 fatigue analyses, except those discussed in LRA Sections 4.3.2.1 through 4.3.2.4. The staff reviewed LRA Section A3.2.1 consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the reviewer verifies that the applicant has provided information to be included in the FSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the FSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2, and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA for the vessels, piping, and components subject to Class 1 fatigue analyses, except those discussed in LRA Sections 4.3.2.1 through 4.3.2.4, as required by 10 CFR 54.21(d).

4.3.2.D Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of metal fatigue on the intended functions of the vessels, piping, and components subject to Class 1 fatigue analyses, except those discussed in LRA Sections 4.3.2.1 through 4.3.2.4, will be adequately managed by the Fatigue Monitoring Program for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.2.1 Reactor Coolant Pump Thermal Barrier Flange

4.3.2.1.1 Summary of Technical Information in the Application

LRA Section 4.3.2.1 states that the fatigue waiver conditions of the ASME Code are satisfied for the RCP, but a cumulative usage factor was calculated as part of simplified elastic-plastic analyses for the thermal barrier flange at component cooling water (CCW) connection. The fatigue analysis of the thermal barrier flange at CCW connection results in a CUF of 0.9334, which uses auxiliary seal injection and CCW transients in addition to the design basis shown in FSAR 3.9(N)-1 SP.

LRA Section 4.3.2.1 states that the auxiliary seal injection and component CCW transients used in the design of the RCP thermal barrier flange include the following:

No. 1 seal injection

- 180 cycles of seal injection flow temperature change
- 200 cycles of elevated seal water injection temperature
- 40 cycles of loss of seal injection flow

CCW connection

- 200 cycles of elevated CCW injection temperature
- 40 cycles of seasonal temperature change
- 200 cycles of loss of CCW flow

The LRA states that the numbers of the plant cooldown, seal injection flow temperature change, elevated seal water injection temperature change, elevated CCW injection temperature, loss of seal injection, and complete loss of CCW flow transients will be tracked by the Fatigue Monitoring Program, as shown in LRA Table 4.3-2. Since the seasonal temperature change is the only transient not counted, its usage contribution during the period of extended operation can be estimated by multiplying its 40-year usage contribution by 1.5, which causes the CUF to exceed the ASME Code allowable of 1.0. LRA Section 4.3.2.1 also discusses an evaluation that was performed to ensure the CUF will be less than 0.9 for the period of extended operation, by limiting the number of cycles due to elevated CCW injection temperature to 75 percent of its design value, or 150 cycles.

The applicant dispositioned the TLAA for the RCP thermal barrier in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of metal fatigue on the intended functions will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

4.3.2.1.2 Staff Evaluation

The staff reviewed LRA Section 4.3.2.1 and the TLAA for the RCP thermal barrier flange to verify, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of fatigue will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

The staff reviewed the applicant's TLAA for the RCP thermal barrier flange 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 verify the appropriateness of the applicant's program for monitoring and tracking the number of critical thermal and pressure transients for the selected RCS components.

The staff noted that the applicant monitors all the transients, except the seasonal temperature change transient, used in the fatigue analysis of the RCP thermal barrier flange with its Fatigue Monitoring Program. The staff determined that the program includes three monitoring methods (cycle counting, CBF monitoring, and SBF monitoring) that are capable of managing metal fatigue during the period of extended operation. The staff also determined that the use of these three monitoring methods progressively provides a more refined monitoring approach to manage metal fatigue to ensure that the applicable allowable design limits are not exceeded. The staff determined that these characteristics of the applicant's Fatigue Monitoring Program are consistent with GALL Report AMP X.M1. The staff's evaluation of the Fatigue Monitoring Program is documented in SER Section 3.0.3.2.22. The staff finds that the Fatigue Monitoring Program ensures the validity of the fatigue analyses through the period of extended operation. The staff's review of the basis that the seasonal temperature change transient is not monitored is documented below.

The LRA states that the seasonal temperature change transient is the only transient not counted; thus, its usage contribution during the period of extended operation can be estimated by multiplying its 40-year usage contribution by 1.5, which results in the CUF exceeding the ASME Code allowable of 1.0. It also states that the transient that contributes most significantly to fatigue is the 200 cycles of elevated CCW injection temperature. To account for the increase

in usage described above caused by the 20 additional years of operation and to keep the usage below the ASME Code allowable of 1.0, the LRA states that the number of the most severe transient will be limited to 75 percent of its design value (i.e., limited to 150 elevated CCW injection temperature), which will keep the CUF less than 0.9.

Additional information regarding the CUF contribution for each of the transients in the original fatigue analysis for this component is required for the staff to verify the adequacy of the TLAA disposition. It is not clear to the staff whether the applicant has performed a CUF "re-calculation" consistent with ASME Code Section III NB-3222.4(e)(5) Step 1 to arrive at its conclusion.

By letter dated September 6, 2012, the staff issued RAI 4.3-13 requesting the applicant provide the CUF contribution, as documented in the original fatigue evaluation, for each of the transient pairings (including the number of cycles used in each pairing) consistent with ASME Code NB-3222.4(e)(5). The applicant also was requested to confirm that the CUF value has been recalculated consistent with ASME Code Section III NB-3222.4(e)(5) to reach its conclusion to restrict the occurrence of the elevated CCW injection temperature and to justify that the accumulated fatigue usage will remain less than 0.9 without monitoring or confirmation that the number of occurrences of the seasonal temperature change transient will not exceed the design limit.

In its response dated October 11, 2012, the applicant provided the CUF contributions from the thermal barrier stress report, as documented in the original fatigue evaluation, for each of the transient pairings (including number of cycles used in each pairing) consistent with ASME Code NB-3222.4(e)(5). (The staff noted a typographical error in RAI 4.3-13 and the applicant's response – reference to ASME Code NB 3224(e)(5) is meant to be ASME Code NB 3222.4(e)(5).) The applicant also confirmed that the conclusion of restricting the occurrence of the elevated CCW injection temperature to 75 percent of the design limit will result in a CUF of less than 0.9 was determined with an evaluation that is consistent with ASME Code Section III NB-3222.4(e)(5). The staff noted that ASME Code Subsection NB-3222.4(e)(5) provides the required procedures to analyze cyclic loading.

The staff noted that, for design purposes, a seasonal temperature change is represented by the CCW temperature dropping instantaneously from an initial temperature of 54 °C (130 °F) to a minimum of 8 °C (47 °F) and then returned instantaneously to 54 °C (130 °F). This is assumed to occur once per year. The staff noted that the seasonal temperature change transient is the only transient that is not counted and only contributes 0.24 to the recalculated CUF of 0.8915. However, the staff noted that it is reasonable to assume that the actual occurrence of this transient will not be as severe because the change in CCW temperature will be slow and gradual rather than being instantaneous, as assumed in the design analysis.

Thus, the staff finds it reasonable that the design limit of 1.0 will be not exceeded during the period of extended operation if this transient is not monitored because: (1) the contribution to the CUF from each occurrence of this transient will be less than anticipated by the design report, as described above, (2) the staff confirmed that the applicant cycle counts all other transients used in the fatigue evaluation of the thermal barrier flange at the CCW connection, and (3) the Fatigue Monitoring Program will include cycle count action limits that will permit completion of corrective actions if the design limits are expected to be exceeded within the next three fuel cycles. Therefore, the staff finds the applicant response acceptable and its concern described in RAI 4.3-13 is resolved.

The staff noted that the thermal barrier flange at No. 1 seal injection and at the CCW connection will be managed by cycle counting, as part of the Fatigue Monitoring Program, which involves initiating corrective actions if the cycle count for any one transient approaches an action limit. The staff finds that this method of monitoring will ensure that the recalculated CUF will not be approached, let alone the design limit of 1.0. The staff's evaluation of cycle counting monitoring method and the Fatigue Monitoring Program is documented in SER Section 3.0.3.2.22.

The staff determined that this program also includes CBF monitoring and SBF monitoring that are capable of managing metal fatigue, which progressively provide a more refined monitoring approach to manage metal fatigue to ensure that the applicable allowable design limits are not exceeded. The staff determined that these characteristics of the applicant's Fatigue Monitoring Program are consistent with GALL Report AMP X.M1.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of metal fatigue on the intended functions of the RCP thermal barrier flange 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 is crediting its Fatigue Monitoring Program to manage metal fatigue to ensure that the allowable design limits on fatigue usage are not exceeded during the period of extended operation; otherwise, the applicant will take corrective actions in accordance with its program.

4.3.2.1.3 FSAR Supplement

LRA Section A3.2.1.1 provides the FSAR supplement summarizing the RCP thermal barrier flange at CCW connection. The staff reviewed LRA Section A3.2.1.1, consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the reviewer verifies that the applicant has provided information to be included in the FSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

The staff noted that LRA Section A3.2.1.1 states that the transients used in the fatigue analysis of the thermal barrier flange at the CCW connection will be tracked by the Fatigue Monitoring Program; however, the LRA does not identify that elevated CCW injection temperature transients will be limited to 75 percent of its design value and does not clearly indicate that, with the exception of the seasonal temperature change transient, the transients used in the fatigue analysis of the thermal barrier flange at the CCW connection will be tracked by the Fatigue Monitoring Program. Without an explicit reference to the 75 percent limit of the design value of the elevated CCW inlet temperature transients, the proposed FSAR supplement in LRA Section A3.2.1.1 does not reflect an accurate summary description of the program and activities to manage the effects of aging.

By letter dated September 6, 2012, the staff issued RAI 4.3-19 requesting the applicant revise LRA Section A3.2.1.1 to indicate that elevated CCW injection temperature transient will be limited to 75 percent of its design value to accommodate the seasonal temperature change transient in the RCP thermal barrier flange fatigue analysis. The applicant also was requested to revise LRA Section A3.2.1.1 to indicate that, with the exception of the seasonal temperature change transient, the transients used in the fatigue analysis of the thermal barrier flange at the CCW connection will be tracked by the Fatigue Monitoring Program.

In its response dated October 11, 2012, the applicant revised LRA Section A3.2.1.1 to state the following:

> To account for the increase in usage caused by 20 additional years of operation associated with the seasonal temperature change transient in the RCP thermal barrier flange fatigue analysis and to maintain the usage below the ASME Code allowable of 1.0, the elevated CCW injection temperature transient will be limited to 75 percent of its design value, (i.e., limited to 150 transients).
>
> With the exception of the seasonal temperature change transient, the transients used in the fatigue analysis of the thermal barrier flange at the [CCW] connection will be tracked by the Fatigue Monitoring Program, summarized in Section A2.1.

The staff finds the applicant's response acceptable because LRA Section A3.2.1.1 was revised to accurately summarize and provide the details of how the TLAA was evaluated and how the Fatigue Monitoring Program manages metal fatigue in accordance with 10 CFR 54.21(d). In addition, the staff noted that the applicant's Fatigue Monitoring Program will include appropriate cycle count action limits to ensure corrective actions are taken prior to exceeding the design limit of 150 for the elevated CCW injection temperature transient. The staff's evaluation of the Fatigue Monitoring Program is documented in SER Section 3.0.3.2.22. The staff's concern described in RAI 4.3-19 is resolved.

Based on its review of the FSAR supplement, as amended by letter dated October 11, 2012, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2, and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address metal fatigue TLAA of the RCP thermal barrier flange, 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, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of metal fatigue on the intended functions of the RCP thermal barrier flange will be adequately managed by the Fatigue Monitoring Program for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.2.2 Pressurizer Insurge-Outsurge Transients

4.3.2.2.1 Summary of Technical Information in the Application

LRA Section 4.3.2.2 states that Westinghouse Nuclear Safety Advisory Letter NSAL 04-5 describes the thermal transients resulting from a reactor coolant insurge-outsurge during normal heatup and cooldown operations. In addition, the limiting CUF locations for Westinghouse-designed plants are at the heater penetrations and pressurizer surge nozzle. This type of transient was not considered in the original design analyses of the pressurizer because it was assumed that when a pressurizer insurge occurred, the screen covering the surge nozzle opening inside the pressurizer caused mixing of the colder hot leg and hotter pressurizer water. However, instead of mixing, surge line stratification data led to the realization that the cooler, denser, hot leg water flows underneath the pressurizer water, resulting in a moving stratified condition.

To mitigate pressurizer insurge-outsurge transients, the applicant has used modified operating procedures (MOPs) since 1996. Guidance on operations and engineering actions for monitoring and evaluating fatigue if the pressurizer surge line temperature change (ΔT) limits

are exceeded is incorporated into the plant heatup and cooldown procedures. Sample fatigue analyses for typical Westinghouse plants using MOPs show that the expected maximum fatigue for the pressurizer and pressurizer components is expected to remain below the ASME Code limit of 1.0.

To determine if the pressurizer contains a limiting EAF location, the fatigue analyses will be revised to incorporate the effect of insurge-outsurge transients on the pressurizer lower head, surge nozzle, and heater well nozzles at plant-specific conditions. For license renewal, the applicant committed (Commitment No. 36) to monitor the CUF of the limiting location out of the pressurizer lower head, pressurizer surge line nozzle, and heater well nozzles using fatigue monitoring software consistent with RIS 2008-30.

The applicant dispositioned the TLAAs associated with the pressurizer insurge-outsurge transients, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of metal fatigue, including the effects from pressurizer insurge-outsurge transients, on the intended functions will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

4.3.2.2.2 Staff Evaluation

The staff reviewed LRA Section 4.3.2.2 and the TLAA associated with pressurizer insurge-outsurge transients to verify, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of fatigue will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

The staff reviewed the applicant's TLAAs associated with pressurizer insurge-outsurge transients 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 verify the appropriateness of the applicant's program for monitoring and tracking the number of critical thermal and pressure transients for the selected RCS components.

The staff noted that the pressurizer insurge-outsurge transients were not considered in the original design analyses of the pressurizer and that the applicant has mitigated the effects of these transients by using MOPs since 1996. Specifically, the staff noted that the MOPs include guidance for monitoring and evaluating fatigue if the pressurizer surge line ΔT limits are exceeded and were incorporated into the Plant Heatup and Cooldown procedures. In addition, these actions include direction to initiate an engineering evaluation of the surge line accumulated fatigue if the surge line ΔT limits are exceeded. The staff finds it appropriate that the applicant revised its plant procedures to ensure that ΔT limits were incorporated into its plant heatup and cooldown procedures to prevent pressurizer insurge-outsurge transients from significantly affecting the pressurizer surge line by the means of metal fatigue.

LRA Table A4-1 contains Commitment No. 36, which states, "[i]mplement SBF or CBF consistent with RIS 2008-30 to monitor the CUF of the limiting location out of the pressurizer lower head, surge nozzle and heater penetrations to accommodate the insurge-outsurge transient." In addition, LRA Table A4-1 contains Commitment No. 37, which states, in part, that "to determine if the pressurizer contains a limiting EAF location, the fatigue analyses will be revised to incorporate the effect of insurge-outsurge transients on the pressurizer lower head, surge nozzle, and heater well nozzles at plant specific conditions." The staff noted that in LRA Amendment 2, dated May 3, 2012, the applicant revised Commitment No. 37 to state that this portion of the commitment was completed and was revised to state, in part, that "[t]he pressurizer contains a limiting EAF location. The fatigue analyses will be revised to incorporate the effect of insurge-outsurge transients in the pressurizer lower head."

Based on the completed portion of Commitment No. 37 and the revision to Commitment No. 37, it is not clear to the staff whether the effects of insurge-outsurge transients have been incorporated into the fatigue analyses of the pressurizer. Furthermore, based on LRA Table 4.3-7, as amended by letter dated May 3, 2012, there are a total of seven sentinel locations for three different regions (pressurizer lower head, pressurizer spray, and pressurizer SRV/PORV) of the pressurizer, which contradicts the revised Commitment No. 37 statement that the pressurizer contains a single limiting EAF location.

Considering the completed portion of Commitment No. 37 described above, the staff noted that LRA Sections 4.3.2.2 and A3.2.1.2 were not revised to capture the incorporation of insurge-outsurge transients on the pressurizer lower head, surge nozzle, and heater well nozzles at plant-specific conditions. In addition, the staff noted that locations to be monitored are different between LRA Section A3.2.1.2 and Commitment No. 36. Thus, it is not clear to the staff what the basis is for the discrepancy. Furthermore, it is not clear how the effects of insurge-outsurge transients were incorporated into the fatigue analyses of the pressurizer before the implementation of MOPs in 1996.

By letter dated September 6, 2012, the staff issued RAI 4.3-12, Parts (a) through (c), requesting the applicant provide the basis for the discrepancies identified by the staff in LRA Sections 4.3.2.2 and A3.2.1.2 and Commitment No. 37. In addition, RAI 4.3-12, Part (d), requested the applicant to clarify the locations to be monitored for CUF using fatigue monitoring software and revise LRA Section A3.2.1.2 and Commitment No. 36 to address the discrepancy in monitored locations. Finally, RAI 4.3-12, Part (d), requested the applicant to explain and justify how pre-MOP insurge-outsurge transients were incorporated into the fatigue analyses of the pressurizer.

In its response to RAI 4.3-12, Part (a), dated October 11, 2012, the applicant clarified that the incorporation of the insurge-outsurge transient into the design analysis for the pressurizer lower head, surge nozzle, and heater well nozzles was completed after submittal of the May 3, 2012, LRA Amendment 2. The staff noted that LRA Section 4.3.2.2, LRA Section A3.2.1.2, and Commitment No. 37 have been revised as part of the response to RAI 4.3-12 to indicate the fatigue analyses have been revised to incorporate the effect of insurge-outsurge transients on the pressurizer lower head, surge nozzle, and heater well nozzles at plant-specific conditions. The revision also demonstrated that the environmentally-adjusted fatigue usage factor (CUF_{en}) are less than 1.0. In addition, the applicant indicated that metal fatigue of components associated with the pressurizer insurge-outsurge transients, including the effects of the reactor coolant environment on fatigue usage factors, will be managed for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii). The staff finds these revisions acceptable because the LRA clearly identifies that re-analysis of the pressurizer components to include the effect of insurge-outsurge transients has been completed and that metal fatigue will be managed for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). The staff's review of the applicant's aging management method is discussed below. The staff's review of the applicant's EAF analyses, including the effect of insurge-outsurge transients on the pressurizer lower head, surge nozzle, and heater well nozzles is documented in SER Section 4.3.4.2.

In its response to RAI 4.3-12, Part (b), the applicant clarified that the only thermal zone affected by the insurge-outsurge transient is the pressurizer lower head and that the CUF values for the pressurizer lower head components in LRA Table 4.3-7, as revised by letter dated May 3, 2012, account for the insurge-outsurge transient. The staff noted that the other sentential locations identified for the pressurizer in LRA Table 4.3-7 were associated with the pressurizer spray,

safety relief valve, or PORVs, not the pressurizer lower head. The staff finds it acceptable that the applicant clarified that all applicable pressurizer components have incorporated the effects of insurge-outsurge transients, and these locations are being managed for environmentally assisted fatigue.

In response to RAI 4.3-12, Part (c), the applicant stated that the insurge-outsurge analysis was not complete when the LRA Amendment was submitted on May 3, 2012. The staff notes that LRA Section 4.3.2.2, LRA Section A3.2.1.2, and Commitment No. 37 have been revised as part of the applicant's response to RAI 4.3-12.

In response to RAI 4.3-12, Part (d), the applicant stated that, based on the completed insurge-outsurge analysis and the EAF screening results, the aging of the pressurizer lower head, surge nozzle, and heater well nozzles can be managed without SBF monitoring. Instead, managing fatigue for the pressurizer lower head, surge nozzle, and heater well nozzles will be accomplished with cycle counting. LRA Table 4.3-1 and LRA Appendix A3.2.1.2 were revised as part of the RAI response to remove CUF monitoring of the pressurizer lower head, pressurizer surge nozzle, and pressurizer heater well nozzles. In addition, the applicant also revised LRA Table A4-1 Commitment 36 to indicate that the commitment to implement SBF or CBF monitoring for pressurizer limiting locations is no longer applicable.

The applicant explained that these locations can be monitored by cycle counting because, when the revised CUF values that include the effects of insurge-outsurge transients are updated to include the maximum environmental adjustment factor (F_{en}) value for stainless steel, the resultant CUF_{en} values are less than the design limit of 1.0. The staff noted that, by cycle counting the transients used in the fatigue analysis, the applicant is able to manage metal fatigue and ensure that the assumptions used in these fatigue analysis will not be exceeded without initiating corrective actions to assess the impact. Thus, the staff finds the use of cycle counting, as included in the Fatigue Monitoring Program, is an acceptable method to manage metal fatigue. The staff determined that these characteristics of the applicant's Fatigue Monitoring Program are consistent with GALL Report AMP X.M1. The staff's evaluation of the Fatigue Monitoring Program is documented in SER Section 3.0.3.2.22.

The applicant stated in its response to RAI 4.3-12, Part (d), that insurge-outsurge transients before implementation of MOPs were derived from WCAP-12893, "Structural Evaluation of the Wolf Creek and Callaway Pressurizer Surge Lines, Considering the Effects of Thermal Stratification," dated March 1991. The applicant clarified that the plant-specific applicability of these transients was addressed in WCAP-12893 through the use of surge line monitoring results, plant operating procedure and operator interviews, and plant historical records. The staff finds it reasonable that the applicant used WCAP-12893 to derive pre-MOP insurge-outsurge transients because this document was confirmed to be applicable based on plant-specific data. Since the occurrence of insurge-outsurge transients are concurrent with heatup and cooldown events, the staff finds it reasonable that the applicant determined the number of pre-MOP insurge-outsurge transients experienced through 1996 based on the baseline work to determine cycle counts. The staff's review of the applicant's baseline of transient cycle counts is documented in SER Section 4.3.1.2.2.

The applicant stated in its response to RAI 4.3-12, Part (d), that the insurge-outsurge transients, after implementation of MOPs, are based on modified steam bubble method from WCAP-14950, "Mitigation and Evaluation of Pressurizer Insurge-Outsurge Transients," dated February 1998. Furthermore, these generic transients from WCAP-14950 were compared to the plant-specific recorded data from October 1995 (date when automated cycle counting was initiated) to

June 2010 and the insurge-outsurge transients were constructed to be representative of the site. The staff finds it acceptable that data from WCAP-14950 were used to construct post-MOP insurge-outsurge transients because the applicant compared the data to its plant-specific recorded data to ensure the transients were representative.

The staff noted that the actions in Commitment No. 36 and portions of Commitment No. 37 related to pressurizer insurge-outsurge transients were completed by letters dated May 3, 2012, and October 11, 2012. The staff's evaluation of the remaining portion of Commitment No. 37 is documented in SER Section 4.3.4.2.

The staff finds the applicant's response to RAI 4.3-12 acceptable because the applicant revised the LRA to eliminate discrepancies in LRA Sections 4.3.2.2 and A3.2.1.2 and Commitment No. 37. The applicant sufficiently justified, as described above, the use of cycle counting to manage the pressurizer lower head components affected by insurge-outsurge transients, and the applicant adequately incorporated the occurrences of pre-MOP and post-MOP insurge-outsurge transients, as described above. Therefore, the staff's concern described in RAI 4.3-12 is resolved.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of metal fatigue on the intended functions of the pressurizer components affected by insurge-outsurge transients 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 has updated its fatigue analysis to incorporate insurge-outsurge transients and is crediting its Fatigue Monitoring Program to manage metal fatigue to ensure that the allowable design limits on fatigue usage are not exceeded during the period of extended operation; otherwise, the applicant will take corrective actions, in accordance with its program.

4.3.2.2.3 FSAR Supplement

LRA Section A3.2.1.2 provides the FSAR supplement summarizing the TLAA for pressurizer components affected by insurge-outsurge transients. The staff reviewed LRA Section A3.2.1.2, as amended by letter dated October 11, 2012, consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the reviewer verifies that the applicant has provided information to be included in the FSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the FSAR supplement, as amended by letter dated October 11, 2012, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2, and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address pressurizer components affected by insurge-outsurge transients, 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, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of metal fatigue on the intended functions of the pressurizer components affected by insurge-outsurge transients will be adequately managed by the Fatigue Monitoring Program for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.2.3 Steam Generator ASME Section III Class 1, Class 2 Secondary Side, and Feedwater Nozzle Fatigue Analyses

4.3.2.3.1 Summary of Technical Information in the Application

LRA Section 4.3.2.3 states that, "[a]lthough the ASME classification for the secondary side of the steam generators is specified to be Class 2, all pressure retaining parts of the steam generator, and thus both the primary and secondary pressure boundaries, are designed to satisfy the criteria specified in Section III of the ASME Code for Class 1 components." Furthermore, the replacement steam generators (RSGs), which were installed during Refuel 14 (Fall 2005), reduced the susceptibility to primary water stress-corrosion cracking (PWSCC) by eliminating all susceptible Alloy 600 and 82/182 material in the steam generators. LRA Table 4.3-4 provides a list of the results from the Class 1 fatigue analyses of the RSG components, which used the design basis numbers of events assumed for a 40-year design life. The RSGs design lives end in 2045, which extends beyond the period of extended operation.
The applicant dispositioned the TLAA for the steam generator ASME Code Section III Class 1, Class 2 secondary side, and feedwater nozzle fatigue analyses, in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid 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 TLAA for steam generator ASME Code Section III Class 1, Class 2 secondary side, and feedwater nozzle to verify, in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid during the period of extended operation.

The staff reviewed the applicant's metal fatigue TLAAs for steam generator ASME Code Section III Class 1, Class 2 secondary side, and feedwater nozzle 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 4.3.2.3 states that the steam generators were installed during Refuel 14 (Fall 2005), which extends the design lives of the replacement steam generators to fall 2045. The staff noted that the components associated with replacement steam generators were designed to satisfy the criteria specified in ASME Code Section III for Class 1 components. In addition, these components were designed and qualified for 40 years, which extends the design lives (Fall 2045) beyond the period of extended operation. Since these components were designed to ASME Code Section III, the staff noted that they were required to have a CUF value less than 1.0 for the design life (i.e., 40 years) to be qualified for service. The staff reviewed LRA Table 4.3-4, which provides the CUF values for replacement steam generator components designed to ASME Code Section III and noted that the 40-year CUF values were less than the ASME Code design limit of 1.0. Since the fatigue analyses for these components indicated CUF values are less than the ASME 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, in accordance with 10 CFR 54.21(c)(1)(i), that the fatigue analyses for the replacement steam generators designed to ASME Code Section III 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 replacement

steam generator components and the associated Class 1, Class 2 secondary side, and feedwater nozzle fatigue analyses extend beyond the period of extended operation.

4.3.2.3.3 FSAR Supplement

LRA Section A3.2.1.3 provides the FSAR supplement summarizing the TLAA for the replacement steam generator components and the associated fatigue analyses. 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 verifies that the applicant has provided information to be included in the FSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the FSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2 and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the replacement steam generator components and the associated fatigue analyses, 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, in accordance with 10 CFR 54.21(c)(1)(i), that the Class 1, Class 2 secondary side, and feedwater nozzle fatigue analyses for the replacement steam generator components remain valid for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.2.4 NRC Bulletin 88-11 Revised Fatigue Analysis of the Pressurizer Surge Line for Thermal Cycling and Stratification

4.3.2.4.1 Summary of Technical Information

LRA Section 4.3.2.4 states that the purpose of NRC Bulletin 88-11 was to (1) request that addressees establish and implement a program to confirm pressurizer surge line integrity in view of the occurrence of thermal stratification, and (2) require addressees to inform the NRC staff of the actions taken to resolve this issue.

The applicant stated that its pressurizer surge line is 14-inch diameter, schedule 160 piping, SA 376 Type 316, except the long-radius elbow, which is SA 376 Type 304, and that the surge line design was reanalyzed to the 1986 ASME Code in response to NRC Bulletin 88-11. This analysis was later reevaluated for effects of snubber removals, and the results of these analyses have been incorporated into the piping and main-loop nozzle code design reports.

Furthermore, the LRA states that the analysis of thermal stratification effects at Callaway evaluated the following locations:

> Hot Leg Surge Nozzle: Westinghouse performed stress analyses of the reactor coolant loop (RCL) branch nozzles, including the effects of thermal stratification. The fatigue result for the [35.6-cm] 14-in. pressurizer surge nozzle on hot leg loop 4 is 0.30, as shown in [LRA] Table 4.3-3, “ASME Class 1 Fatigue Analyses under the Fatigue Monitoring Program.”

> Pressurizer Surge Line: Westinghouse performed stress analyses of the auxiliary piping systems connected to the RCL, including the effects of thermal stratification. The fatigue result for the [35.6-cm] 14-in. pressurizer surge line is 0.099, as shown in [LRA] Table 4.3-3, "ASME Class 1 Fatigue Analyses under the Fatigue Monitoring Program."

The applicant dispositioned the TLAA for the revised fatigue analysis of the pressurizer surge line for thermal cycling and stratification, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of metal fatigue, including thermal cycling and stratification, on the intended functions will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

4.3.2.4.2 Staff Evaluation

The staff reviewed LRA Section 4.3.2.4 and the TLAA associated with the revised fatigue analysis of the pressurizer surge line for thermal cycling and stratification to verify, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of fatigue will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

The staff reviewed the applicant's TLAAs associated with the revised fatigue analysis of the pressurizer surge line for 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 verify the appropriateness of the applicant's program for monitoring and tracking the number of critical thermal and pressure transients for the selected RCS components.

The staff noted that, to address NRC Bulletin 88-11, the 35.6-cm (14-in.) pressurizer surge line design was reanalyzed to the 1986 ASME Code in response to the thermal stratification concerns.

The staff noted that the applicant's response to Question 11 in "Callaway Plant Application of Proprietary Leak-Before-Break Methodology Reports and Draft Regulatory Guide DG-1108," (nonproprietary letter) dated December 9, 2003 (ADAMS Accession No. ML033530468) stated that the value of the maximum ASME Code Section III, Class 1, CUF of the pressurizer surge line previously calculated under the effects of thermal stratification is 0.4. However, LRA Section 4.3.2.4 indicates that the fatigue results, including the effects of thermal stratification, for the 35.6-cm (14-in.) pressurizer surge nozzle on hot leg loop 4 and the 35.6-cm (14-in.) pressurizer surge line are 0.3 and 0.099, respectively. In addition, LRA Table 4.3-7, as amended by letter dated May 3, 2012, also indicates a CUF value of 0.3 for the surge line (hot leg surge nozzle). Based on the reported CUF values in the LRA, including LRA Amendment 2 by letter dated May 3, 2012, and the applicant's response letter, dated December 9, 2003, it is not clear to the staff if the CUF values are referring to the same or different locations of the pressurizer.

By letter dated September 6, 2012, the staff issued RAI 4.3-6, Part (a), requesting that the applicant clarify the specific locations that are represented by the CUF values of 0.099, 0.3, and 0.4. In addition, the staff requested in RAI 4.3-6, Part (b), that the applicant provide the basis for recording a lower CUF value in LRA Section 4.3.2.4 and LRA Table 4.3-7, as amended by letter dated May 3, 2012, if the CUF value of 0.4 refers to the same location as the 35.6-cm (14-in.) pressurizer surge nozzle on hot leg loop 4.

In its response to RAI 4.3-6, Part (a), dated October 11, 2012, the applicant clarified that the CUF values are associated with the pressurizer surge line and hot leg surge nozzles. Specifically, the applicant stated that the CUF value of 0.099 represents the maximum CUF in the surge line piping (i.e., locations between the two terminal ends that include the hot leg surge nozzle and pressurizer surge nozzle). Furthermore, the CUF value of 0.3 represents the hot leg surge nozzle and the CUF value of 0.4 represents the weld between the surge line piping and pressurizer surge nozzle.

The applicant clarified in response to RAI 4.3-6, Part (b), that the CUF value of 0.4, which was reported in the letter dated December 9, 2003, was the result of a supplement to its initial NRC Bulletin 88-11 analysis. Furthermore, the applicant clarified that a structural weld overlay was applied to this weld in 2007 and a fatigue crack growth analysis was performed in accordance with ASME Code Section XI. The staff confirmed that the applicant identified this fatigue crack growth analysis of the structural weld overlay as a TLAA in LRA Section 4.7.2. The staff's evaluation of the applicant's disposition for the fatigue crack growth analysis of the structural weld overlay is documented in SER Section 4.7.2.2.

The staff finds the applicant's response to RAI 4.3-6 acceptable because the locations of the pressurizer associated with the CUF values identified by the staff were clarified, and the applicant reported the bounding CUF values in LRA Section 4.3.2.4 and LRA Table 4.3-7 for the pressurizer. In addition, the staff finds it appropriate that, since a structural weld overlay was applied and a fatigue crack growth analysis was performed for the pressurizer surge nozzle, the CUF value of 0.4 is no longer the licensing or design basis for this location. The staff's concern described in RAI 4.3-6 is resolved.

The staff noted that although the CUF values for the hot leg surge nozzle and pressurizer surge line, including the effects of thermal stratification, are significantly less than the design limit of 1.0, the applicant has proposed to conservatively manage fatigue of these components with its Fatigue Monitoring Program. The staff's review of the applicant's Fatigue Monitoring Program is documented in SER Section 3.0.3.2.22. The staff determined that the program includes three monitoring methods (cycle counting, CBF, and SBF monitoring) that are capable of managing metal fatigue during the period of extended operation. The staff also determined that the monitoring methods progressively provide a more refined monitoring approach to manage metal fatigue to ensure that the applicable allowable design limits are not exceeded. The staff determined that these characteristics of the applicant's Fatigue Monitoring Program are consistent with GALL Report AMP X.M1.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of metal fatigue on the intended functions of the pressurizer surge line and hot leg surge nozzle 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 is crediting its Fatigue Monitoring Program to manage metal fatigue to ensure that the allowable design limits on fatigue usage are not exceeded during the period of extended operation; otherwise, the applicant will take corrective actions, in accordance with its program.

4.3.2.4.3 FSAR Supplement

LRA Section A3.2.1.4 provides the FSAR supplement summarizing the revised fatigue analysis of the pressurizer surge line for thermal cycling and stratification. The staff reviewed LRA Section A3.2.1.4, consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the reviewer verifies that the applicant has provided information to be included in the FSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the FSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2, and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address revised fatigue analysis of the pressurizer surge line for thermal cycling and stratification, 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, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of metal fatigue on the intended functions of the pressurizer surge line will be adequately managed by the Fatigue Monitoring Program for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.3 ASME 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 states that the RVIs were designed after the incorporation of Subsection NG into the 1974 Edition (no addenda) of ASME Code Section III. Plants designed after the incorporation of the Subsection NG have complete fatigue analyses of RVI component low-cycle and high-cycle fatigue usage. Thus, the Callaway RVIs meet Subsection NG in full.

Specifically, for the RVI design basis for low-cycle fatigue, the LRA states that analyses of record for Callaway were confirmed to continue to satisfy the ASME Code Subsection NG requirements. The fatigue analyses were performed using the 40-year design transients in FSAR Table 3.9(N)-1 SP. The baffle, former, and barrel assemblies were qualified by fatigue tests, in accordance with ASME Code Section III, Subsection NG, Article II-1221 for the number of cycles and severity required by the design specification. The fatigue tests were used in lieu of a fatigue analysis; therefore, no CUF exists for these components. Maintaining those components within specified numbers of transients will ensure the tests remain valid.

The applicant dispositioned the TLAA for the RVIs, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of metal fatigue on the intended functions will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

The LRA also states that protection from flow-induced vibration is ensured by satisfying the requirements of RG 1.20, as discussed in FSAR Sections 3.9(N).2.3, 3.9(N).2.4, and 3.9(N).2.6 SP, and includes the results of experimental tests and analyses. The applicant reviewed the supporting references and did not identify any dependence on time. The high-cycle fatigue and flow-induced vibration stresses were not considered in the calculation of the CUFs for the components because the vibratory stresses are very small compared to thermal transient stresses, and the usage from high-cycle effects is insignificant. The applicant stated that the evaluation of high-cycle vibrational loads does not depend on the licensed period and is not a TLAA in accordance with 10 CFR 54.3(a), criterion 3. Furthermore, the LRA states that the PWR Vessel Internals Program will address the aging effects in the reactor internal components, including those that could be induced by a flow-induced vibration mechanism.

In addition, the LRA states that a review of the Callaway licensing basis did not identify a 40-year embrittlement analysis for RVIs.

4.3.3.2 Staff Evaluation

The staff reviewed LRA Section 4.3.3 and the TLAA for the fatigue design of the ASME Code Section III Subsection NG RPV internals to verify, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of fatigue will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

The staff reviewed the applicant's metal fatigue TLAAs for the 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 verify the appropriateness of the applicant's program for monitoring and tracking the number of critical thermal and pressure transients for the selected RCS components.

The staff noted that the fatigue analyses were performed using the 40-year design transients in FSAR Table 3.9(N)-1 SP, which are those transients listed in LRA Table 4.3-2 and monitored by the Fatigue Monitoring Program. In addition, the staff noted that the baffle, former, and barrel assemblies were qualified by fatigue tests in accordance with ASME Code Section III, Subsection NG, Article II-1221 for the number of cycles and severity required by the design specification; therefore, no CUF exists for these components. The staff noted that the transients used in these fatigue waivers specified by the design specification are the same transients discussed in the applicant's FSAR.

The staff reviewed LRA Table 4.3-5, which provides the CUF values for the RVIs, and noted that the 40-year CUF values were less than the ASME Code design limit of 1.0. The staff noted that the applicant monitors the transients used in the fatigue analysis and qualification tests of the RVIs with its Fatigue Monitoring Program. The staff determined that the program includes three monitoring methods (cycle counting, CBF monitoring, and SBF monitoring) that are capable of managing metal fatigue during the period of extended operation. The staff also determined that the monitoring methods progressively provide a more refined monitoring approach to manage metal fatigue to ensure that the applicable allowable design limits are not exceeded. The staff determined that these characteristics of the applicant's Fatigue Monitoring Program are consistent with GALL Report AMP X.M1. The staff's evaluation of the Fatigue Monitoring Program is documented in SER Section 3.0.3.2.22.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging related to fatigue analysis of the RVIs 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 is crediting its Fatigue Monitoring Program, which the staff determined in SER Section 3.0.3.2.22 is consistent with GALL Report AMP X.M1, to manage metal fatigue to ensure that the allowable design limits on fatigue usage are not exceeded during the period of extended operation; otherwise, the applicant will take corrective actions, in accordance with its program.

The applicant stated that protection from flow-induced vibration is ensured by satisfying the requirements of RG 1.20, as discussed in FSAR Sections 3.9(N).2.3, 3.9(N).2.4, and 3.9(N).2.6 SP, and includes the results of experimental tests and analyses. The staff noted that an analysis is only defined as a TLAA if all six criteria outlined in 10 CFR 54.3 are satisfied. The staff reviewed the FSAR and did not identify that design basis for the RVIs for high-cycle fatigue is dependent on the licensed life of the plant period. Thus, the staff finds that all six criteria for a TLAA were not met for the applicant's evaluation of high-cycle fatigue for the RVIs. The staff finds the applicant's determination that high-cycle fatigue of the RVIs is not a TLAA to be acceptable. Although high-cycle fatigue of the RVIs is not evaluated in the application as a

TLAA, the staff noted that the applicant's PWR Vessel Internals Program addresses the aging effects in the reactor internal components, including those that could be induced by a flow-induced vibration mechanism. The staff's evaluation of the PWR Vessel Internals Program is documented in SER Section 3.0.3.1.5.

In addition, the LRA states that the applicant's review of its licensing basis did not identify a 40-year embrittlement analysis for RVIs. As described in the staff's evaluation of this absence of a TLAA in SER Section 4.1.2.1.2, the staff noted that SRP-LR Section 3.1.2.2.3.3 states that "Ductility – Reduction in Fracture Toughness" is a plant-specific TLAA for B&W reactor internals to be evaluated for the period of extended operation, in accordance with the staff's safety evaluation concerning Babcock and Wilcox Owners Group report number BAW-2248 (ADAMS Accession No. ML993490303). The staff reviewed the FSAR and confirmed that the applicant's CLB does not contain or reference a 40-year embrittlement analysis for RVIs. In addition, the staff determined that BAW-2248A is not applicable to the applicant because it is a Westinghouse-designed PWR. The staff also noted that the applicant's PWR Vessel Internal Program manages loss of fracture toughness and reduced material ductility for its RVIs. The staff's evaluation of the PWR Vessel Internal Program is documented in SER Section 3.0.3.1.5.

4.3.3.3 FSAR Supplement

LRA Section A3.2.2 provides the FSAR supplement summarizing the metal fatigue TLAA for the RVIs. 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 verifies that the applicant has provided information to be included in the FSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the FSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2, and is, therefore, acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the metal fatigue TLAA for the RVIs, as required by 10 CFR 54.21(d).

4.3.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of metal fatigue on the intended functions of the RVIs will be adequately managed by the Fatigue Monitoring Program for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.4 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, as amended by letter dated May 3, 2012, states that LRA Table 4.3-6, "Summary of Fatigue Usage Factors at NUREG/CR-6260 Sample Locations," is a summary of EAF of the NUREG/CR-6260 locations. The LRA states that the F_{en} relationships are calculated from NUREG/CR-6583 for carbon and low-alloy steels and from NUREG/CR-5704 for stainless steels, as appropriate for the material at each of these locations. The LRA further states that all of the locations specified in NUREG/CR-6260 for newer-vintage Westinghouse plants listed in Table 4.3-6 will be monitored by the Fatigue Monitoring Program.

The applicant dispositioned the evaluations associated with EAF of the NUREG/CR-6260 locations for a newer vintage Westinghouse plant in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of environmentally assisted fatigue on the intended functions will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

LRA Section 4.3.4, as amended by letter dated May 3, 2012, states that, to ensure that the limiting plant-specific EAF locations are identified, it performed a systematic review of all wetted RCPB components with an ASME Code Section III Class 1 fatigue analysis. This was done either to show that the NUREG/CR-6260 locations are bounding or to incorporate EAF into the licensing basis for those more limiting components. The LRA indicates that the methods in NUREG/CR-5704 (for austenitic stainless steels), NUREG/CR-6583 (for carbon and low-alloy steels), and NUREG/CR-6909 (for Ni-Cr-Fe steels) were used in calculating the F_{en} factors

LRA Table 4.3-7, "Sentinel Locations for EAF Monitoring," identifies the final locations, including the NUREG/CR-6260 locations, that will be used as sentinel locations during the period of extended operation to manage EAF. The LRA states that those non-NUREG/CR-6260 locations with an EAF CUF greater than 1.0 will be evaluated further using the same methods as those used to remove conservatisms for the NUREG/CR-6260 locations. The results of these final analyses will be incorporated into the Fatigue Monitoring Program by either counting the transients assumed or incorporating the stress intensities into a CBF or SBF portion of the program. The applicant dispositioned the evaluations associated with EAF of the non-NUREG/CR-6260 locations in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of EAF on the intended functions will be adequately managed by the Fatigue Monitoring Program 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, 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 Fatigue Monitoring 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, in accordance with 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. SRP-LR Section 4.3.3.1.3 states that "if an applicant has chosen to assess the impact of the reactor coolant environment on a sample of critical components, the reviewer verifies [that] the critical components include a sample of high-fatigue usage locations." SRP-LR Section 4.3.3.1.3 also states that 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 additional locations based on plant-specific considerations.

LRA Section 4.3.4 states that the NUREG/CR-6260 locations in LRA Table 4.3-6 with an EAF CUF below 1.0, when using the design basis CUF and the maximum F_{en}, require no further analysis. The staff reviewed LRA Table 4.3-6 and noted that these locations, which are all fabricated of low-alloy steel, include the RPV lower head to shell juncture, RPV inlet nozzle, and RPV outlet nozzle. The staff noted that the F_{en} value used for these locations was 2.45 and calculated using the NUREG/CR-6583. The staff noted that this is the maximum F_{en} value for low-alloy steel components exposed to a PWR reactor coolant, which is a low-oxygen environment. The staff noted that the applicant's Water Chemistry Program maintains reactor coolant system hydrogen level to ensure that the PWR reactor coolant remains a low oxygen environment. Based on the applicant's plant operation and Water Chemistry Program, the staff finds the applicant's use of this F_{en} value appropriate for these low-alloy steel components.

LRA Section 4.3.4 states that the remaining NUREG/CR-6260 locations were re-evaluated with a refined fatigue analysis using NB-3200 methods in a three-dimensional (3-D) finite element analysis model using the design number of transients to reduce the CUF values. Furthermore, after this reanalysis the RHR inlet transition was the only location to pass the EAF CUF criterion of 1.0. The staff finds the use of NB-3200 methods in a 3-D finite element analysis model to reduce the RHR inlet transition EAF CUF to less than 1.0 acceptable because the use of NB-3200 is consistent with ASME Code Section III and the use of a 3-D finite element analysis model provides a more refine model to address the response of the component from the applied stress.

The staff noted that the RPV lower head to shell juncture, RPV inlet nozzle, RPV outlet nozzle and RHR inlet transition will be monitored by the CBF monitoring method of the Fatigue Monitoring Program, as indicated in LRA Table 4.3-1. Since these locations are monitored with CBF, the staff noted that the EAF CUF will be updated as transients occur. In addition, this provides an up-to-date cumulative fatigue usage of the component that is based on the design usage contribution for each transient occurrence. The staff finds the Fatigue Monitoring Program is capable of managing the EAF CUF of the RPV lower head to shell juncture, RPV inlet nozzle, and RPV outlet nozzle below 1.0. The staff's review of the CBF monitoring method and the Fatigue Monitoring Program are documented in SER Section 3.0.3.2.22.

LRA Section 4.3.4 states that there are two options available to further reduce the EAF CUFs for the charging system nozzles, safety injection nozzles, and hot leg surge line nozzle that include calculating a strain-rate dependent F_{en} and/or calculating a CUF based on the 60-year projected number of transient events. The staff's evaluation of each option is discussed below.

The strain-rate dependent F_{en} values are calculated for the significant load set pairs in the fatigue analyses using the integrated strain-rate method. The staff noted that the integrated strain-rate approach to determine the F_{en} values is rigorous because the strain-rate is computed for multiple points along the tensile portion of the paired strain range resulting in a more refined F_{en} value. The staff finds the applicant's approach to determine strain-rate dependent F_{en} values reasonable because it used the strain-rate and water temperature that were calculated from the design transient specifications and stress analyses, which allows for a more refined value.

The applicant stated that load set pairs that produce no significant stress range or fatigue contribution were assigned the maximum F_{en} for the material. Since the applicant used the maximum F_{en} for load set pairs that produce no significant stress range or fatigue contribution, the staff finds this conservative. The LRA indicates that a dissolved oxygen content of less than 0.05 ppm was assumed, which corresponds to a low-oxygen environment, for the charging

system nozzles, safety injection nozzles, and hot leg surge line nozzle. The staff noted that these components are fabricated from stainless steel, thus, the use of a low dissolved oxygen environment yields higher F_{en} values, which the staff finds conservative.

The LRA indicates that, even with the use of the strain-rate dependent F_{en} values, the results for EAF CUF of the charging system nozzles, safety injection nozzles, and hot leg surge line nozzle were still greater than 1.0. The staff noted that the numbers of transients projected to 60 years of operation as provided in LRA Table 4.3-2 were used in order to further refine the EAF CUF values to less than 1.0. The staff's review of the applicant's 60-year projection methodology is documented in SER Section 4.3.1.2.2.

LRA Section 4.3.4 states that if the cycle count for a transient is not projected, then the full number of design basis events is used, with the exception of two transients, "inadvertent safety injection" and "loss of power" events, which were analyzed based on the number of events that occurred as of 2011. The LRA further states that the only EAF CUF calculation that is significantly affected by these transients is the safety injection nozzle. The staff noted that the projected safety injection nozzle EAF CUF is 0.74 and is monitored by the CBF monitoring method of the Fatigue Monitoring Program, as indicated in LRA Table 4.3-1. This location is analyzed for the numbers of "inadvertent safety injection" and "loss of power" events to date, since it is monitored with CBF, which updates the EAF CUF and will be updated as additional events occur. Thus, the staff finds the Fatigue Monitoring Program is capable of managing the EAF CUF of the safety injection nozzle less than 1.0. The staff's review of the CBF monitoring method and the Fatigue Monitoring Program are documented in SER Section 3.0.3.2.22.

The staff noted that, with the use of 60-year cycle projections and strain-rate dependent F_{en} values, the calculated hot leg surge line nozzle EAF CUF is 0.765. The staff noted that this location is being monitored by the cycle counting method of the Fatigue Monitoring Program. The staff's review of the cycle counting method and the Fatigue Monitoring Program are documented in SER Section 3.0.3.2.22. The staff determined that this method will monitor transient occurrences to ensure that the number of assumed in transients in the hot leg surge line nozzle EAF analysis will not be exceeded through the period of extended operation. Otherwise, corrective actions will be taken. The staff finds the use of cycle counting for the hot leg surge line nozzle acceptable because it ensures the EAF analysis remains valid or it will identify that corrective actions are necessary to prevent the calculated EAF CUF from being exceeded.

The staff noted that LRA Table 4.3-3 states that the CUF value for the Class 1 piping of "Normal/Alternate Charging - Loops 1 & 4" is 0.93, whereas LRA Table 4.3-7, as amended by letter dated May 3, 2012, states that the "Normal Charging Nozzles, Loop 1" and "Alternate Charging Nozzles, Loop 4" have CUF values of 0.90. These locations identified in LRA Table 4.3-7 are the sentinel locations for EAF monitoring for the "Charging" thermal zone within the chemical and volume control system (CVCS). Based on the information in the LRA tables, it was not clear to the staff why the normal and alternate charging nozzles would bound Class 1 piping of "Normal/Alternate Charging - Loops 1 & 4," given that the CUF values of the Class 1 piping of "Normal/Alternate Charging - Loops 1 & 4" is higher.

By letter dated September 6, 2012, the staff issued RAI 4.3-9 requesting the applicant to provide justification that the normal and alternate charging nozzles are sentinel locations for the "Charging" thermal zone within the CVCS. As part of the justification, the applicant was requested to include the materials, transients experienced, system configuration, water chemistry, and other factors when comparing the Class 1 piping and nozzles.

In its response to RAI 4.3-9 dated October 11, 2012, the applicant clarified that the CUF value of 0.9 for the charging nozzle was more recently computed in response to high letdown flow, which focused exclusively on the charging nozzle, since it was determined to be the controlling location. In addition, the applicant stated that the CUF value for the charging nozzle taken from the same design report revision as the charging piping CUF value of 0.93 is equal to 0.95. The applicant also confirmed that the charging piping and charging nozzle are constructed of stainless steel, and that the CUF values of both are based on the same design transients in LRA Table 4.3-2 and the same system configuration that rotates between normal and auxiliary charging paths.

Since the charging piping and nozzle were fabricated from the same material and experienced the same design transients and the same system rotation between normal and auxiliary charging paths, the staff finds it reasonable that the charging nozzle that has a higher CUF value than that of the charging piping, when compared from the same design report revision, represents the bounding location for considering EAF. The staff finds the applicant's response acceptable because the applicant gave sufficient justification, as described above, that the charging nozzle was appropriately selected as the "sentinel location" for considering EAF for the charging zone of the CVCS. The staff's concern described in RAI 4.3-9 is resolved.

The staff noted that, in some instances, multiple loops on a particular system may have the same CUF value, and in other instances, they have different CUF values; thus, the basis for multiple loops having the same CUF value is not clear. The LRA did not annotate or explain if the CUF values, for entries of multi-loop systems in LRA Tables 4.3-3 to 4.3-7, are intended to demonstrate that the CUF value of one loop bounds the "calculated" CUF value of another, or to demonstrate that the CUF value of one loop represents all other identical or less limiting loops. Without a clear indication of the CUF values of multi-loop systems, the staff cannot confirm the applicant's conclusion that LRA Table 4.3-7 identifies the final locations, including the NUREG/CR-6260 locations that will be used as sentinel locations during the period of extended operation to manage EAF.

By letter dated September 6, 2012, the staff issued RAI 4.3-7 requesting the applicant to identify any components or locations in LRA Tables 4.3-3 to 4.3-7 for which the CUF value in the design-basis calculation is the same for each loop in a multi-loop system. In addition, the applicant was requested to identify any components or locations in the aforementioned LRA Tables for which (1) a CUF value of one loop was used to bound any "calculated" CUF values of another loop in a multi-loop system, including a basis for each circumstance and (2) the CUF value of one loop represented all other identical or less limiting loops, including a basis for each circumstance.

In its response to RAI 4.3-7 dated October 11, 2012, the applicant provided a list of 10 systems with multiple loops from LRA Table 4.3-3 and 4 systems with multiple loops from LRA Table 4.3-7 in which the maximum CUF value from the design basis calculation is the same for each loop in a multi-loop system. The applicant confirmed that each loop from these systems has been independently analyzed for fatigue. Since the applicant confirmed that each loop of these systems were independently analyzed for fatigue and the maximum CUF value from the design basis calculation is the same for each loop, the staff finds the locations and CUF values identified in LRA Tables 4.3-3 and 4.3-7 to be appropriate.

The applicant stated in its response that the maximum CUF for the "Spray/Aux. Spray Loop 1 & 2" location in LRA Table 4.3-3 was used to bound all CUF values in this multi-branch system. The applicant also explained that the location of the maximum CUF of 0.84 is in the

common section of piping leading to the pressurizer spray nozzle. Since the location of the maximum CUF value is shared by both loops on a common section of piping, the staff finds it reasonable that this CUF value of 0.84 was used to represent this multi-branch system.

The applicant stated that the maximum CUF for the "Pressurizer Safety and Relief Valve Piping" location in LRA Tables 4.3-3 and 4.3-6 was used to bound all CUF values in this multi-branch system. The applicant indicated that the maximum CUF of 0.975 is in the safety valve piping and the maximum CUF in the relief valve piping is 0.970. The staff reviewed FSAR Section 5.1.3 and noted that the pressurizer safety and relief valve piping share similar functions and, thus, experience similar thermal transients. In addition, the staff noted in LRA Table 4.3-7 that the pressurizer safety and relief valve piping are fabricated of stainless steel. Since these systems experience similar transients and are fabricated of the same material, the staff finds it reasonable that the maximum CUF of 0.975 for the safety valve piping was used to be representative of this multi-branch system.

The applicant provided a list of components, with associated CUF values, for components and/or locations in LRA Tables 4.3-3, 4.3-4, 4.3-6 and 4.3-7 in which one model represents multiple plant locations. The applicant clarified that these components and/or locations that represent multiple plant locations have identical geometry, material, and the thermal transients for the locations that share the analyses. Thus, the staff finds it reasonable for these components that one CUF value is representative of identical components and/or locations.

The staff finds the applicant's response acceptable because the applicant clarified and provided sufficient justifications, as described above, (1) when a CUF value in the design-basis calculation is the same for each loop in a multi-loop system; (2) when a CUF value of one loop was used to bound the "calculated" CUF values of another loop; and (3) when a CUF value of one loop represented all other identical or less limiting loops. In addition, the clarification assists the staff in determining if the applicant selected the appropriate "sentinel" locations to manage EAF, as discussed below. The staff's concern described in RAI 4.3-7 is resolved.

The staff noted that the projected normal and alternate charging nozzles EAF CUFs based on the SBF algorithm are 0.57 and 0.53, respectively. The LRA states that the SBF usage factors were benchmarked against NB-3200 methods consistent with RIS 2008-30, as discussed in LRA Section 4.3.1.1. The staff's review of the applicant's benchmarking evaluation for the normal and alternate charging nozzles is documented in SER Section 4.3.1.1.2. The staff determined that the benchmarking evaluation for the normal and alternate charging nozzles demonstrated that SBF can be used for these nozzles and that the concerns identified in RIS 2008-30 are not applicable for these nozzles. The staff's review of the SBF monitoring method and the Fatigue Monitoring Program is documented in SER Section 3.0.3.2.22. The staff determined that the SBF monitoring method periodically calculates cumulative fatigue usage based on the conditions that are actually occurring at the applicant's site during transients to ensure the design limit is not exceeded through the period of extended operation.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of EAF on the intended functions of the NUREG/CR-6260 locations for a newer vintage Westinghouse plant 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 its Fatigue Monitoring Program with the use of the cycle counting, CBF, and SBF monitoring methods, as described above, is capable of managing EAF to ensure that the allowable design limits on fatigue usage are not exceeded during the period of extended operation; otherwise, the applicant will take corrective actions in accordance with its program.

LRA Section 4.3.4, as amended by letter dated May 3, 2012, states that the CUF for wetted RCPB locations were categorized based on the strain rate of the dominant transient, which was determined with a qualitative assessment based on experience and not a quantitative stress analysis. In addition, it states that this estimated strain rate was used to calculate an estimated F_{en}. This estimated F_{en} was then averaged with the maximum F_{en} for that material type to calculate the average F_{en}, which was used with the design basis CUFs to calculate the estimated EAF CUF. The LRA indicated that the estimated F_{en} value was based on NUREG/CR-5704 for austenitic stainless steels, NUREG/CR-6583 for carbon and low alloy steels and NUREG/CR-6909 for Ni-Cr-Fe steels. These estimated EAF CUFs were then organized according to their system, thermal zone, and material type. LRA Section 4.3.4 defines a thermal zone as a collection of piping and/or vessel components which undergo essentially the same group of thermal and pressure transients during plant operations.

The staff noted that since the estimated strain rate was determined based on a qualitative assessment, judgment of the appropriate strain rate must be made based on knowledge of, at a minimum, the transient, system and/or thermal zone in question. However, the applicant did not provide the details of how this qualitative assessment was performed for its plant nor was it justified that this approach was appropriate or conservative for its plant. In addition, the staff noted that since the estimated EAF CUFs were organized according to their system, thermal zone and material type, to have a meaningful comparison of the EAF CUFs, it is important that the CUFs were assessed similarly (e.g., amount of rigor in calculating CUF) and used the same fatigue curves in ASME Code, Section III, Appendix I.

In addition, the staff noted that LRA Section 4.3.4, as amended by letter dated May 3, 2012, indicates that an initial screening list may have been reduced by using one of the following methods:

- One thermal zone can bound another thermal zone in a system.
- One material in a thermal zone can bound other materials in the same thermal zone.
- One material in a thermal zone can bound other materials in another thermal zone.

Since the initial screening list may have been reduced by using one of the methods described above, which is based on the CUF, F_{en}, thermal zone and material type, the staff noted that to have a meaningful comparison to screen EAF CUFs, it is important that the CUFs were assessed similarly (i.e., amount of rigor in calculating CUF) and used the same fatigue curves in ASME Code Section III, Appendix I. In addition, the applicant did not provide specific examples of how/when these methods were used to reduce the initial screening list; therefore, it is not clear how each method was applied and a basis was not provided to support that these methods are appropriate and conservative.

Therefore, by letter dated September 6, 2012, the staff requested the applicant in RAI 4.3-20, Part (a), to describe the qualitative assessment that was used to categorize the CUF for wetted RCPB locations based on the strain rate of the dominant transient and provide the basis that this assessment is appropriate or conservative for the Callaway plant.

In its response dated October 11, 2012, the applicant stated a qualitative estimate of the strain rate for the controlling fatigue transient(s) was determined based on experience with its corresponding plant system, and these categorizations of strain rate were guided by transient descriptions described in system design documents. In addition, based on experience with fatigue analyses of many plant components, a strain-rate category was selected to represent each component. The applicant explained that this selection was based on ranking the

identified transients that would govern the CUF of the component with respect to how quickly the maximum and minimum stress states would be established.

The staff finds it appropriate that the categorization of strain rate was based on plant-specific experience from the corresponding plant system and the transient descriptions from the system design documents. The staff also finds the ranking with respect to how quickly the maximum and minimum stress states are established to be acceptable because it establishes an estimated F_{en} value for the component that supports the calculation of reasonable average F_{en} values, which is further discussed below, used to identify potential EAF monitoring locations. RAI 4.3-20, Part (a), is resolved.

In addition, by letter dated September 6, 2012, the staff requested the applicant in RAI 4.3-20, Part (b), to provide the reason that the method for calculating the average F_{en} (i.e., average of the estimated F_{en} and the maximum F_{en} for the material type) is appropriate and conservative for the plant-specific conditions.

In its response dated October 11, 2012, the applicant stated the average F_{en} (average of the estimated F_{en} and maximum F_{en}) is appropriate and conservative because the two-part average F_{en} is based on experience with performing detailed F_{en} analyses. The applicant explained that, in general, the effective F_{en} from a detailed analysis is similar to the F_{en} value computed for just the controlling transient pairs, but only slightly offset due to contributions from the less-significant fatigue pairs. Thus, the applicant determined that choosing an average F_{en} halfway between the estimated F_{en} and the maximum F_{en} for a given material provides assurance that the average F_{en} is higher than the effective F_{en}. In addition, the applicant stated that the resulting estimated U_{en} values are compared to a conservative threshold value of 0.8 for inclusion in the ranking of EAF monitoring locations.

The staff noted that LRA Section 4.3.4, as amended by letter dated April 26, 2013, states that the estimated F_{en} is based on assuming a low dissolved oxygen environment, the maximum fluid/metal temperature, and maximum sulfur concentration, and is based on the methods in NUREG/CR-5704 (stainless steels and nickel alloys) and NUREG/CR-6583 (carbon and low-alloy steel). The staff finds the applicant's assumptions for dissolved oxygen to be appropriate because the applicant's water chemistry program maintains a low-dissolved oxygen environment. In addition, the staff finds the applicant's assumption on fluid/metal temperature and sulfur concentration to be conservative because the use of maximum values will result in a larger F_{en} value.

The staff finds the applicant's use of an average F_{en} in the ranking of EAF monitoring locations reasonable and acceptable because (1) in general, the average F_{en} is greater than the calculated F_{en} in a detailed EAF analysis, (2) the applicant set a U_{en} threshold value of 0.8 for inclusion into the ranking of EAF monitoring locations, which accounts for the variances in the average F_{en} and the calculated F_{en} in a detailed EAF analysis, and (3) the applicant made appropriate or conservative assumptions for dissolved oxygen, fluid/metal temperature and sulfur concentration in the calculation of F_{en} values, as described above. RAI 4.3-20, Part (b), is resolved.

Furthermore, by letter dated September 6, 2012, the staff requested the applicant in RAI 4.3-20, Part (c), to provide the basis for ranking or comparing the EAF CUFs to one another to determine an EAF monitoring location if EAF CUFs (1) were not organized according to their system, thermal zone, and material type; (2) were not assessed similarly (e.g., amount of rigor in calculating CUF); and (3) did not use the same fatigue curves in ASME Code Section III Appendix I in order to provide a meaningful comparison.

In its response dated October 11, 2012, the applicant explained that, based on the ASME Code edition used in the fatigue analyses, it assumed that the same fatigue curves for each material used for the analyses were relied upon for the screening process. In addition, the applicant explained that the level of analytical rigor by the fatigue analyst was not specifically reviewed; however, the CUF values used in the screening were developed from the same generation of analyses and are expected to have been performed using the same level of rigor (i.e., elastically determined stresses with the same transient list and severity using the same ASME Code, Section III, Appendix I fatigue curve). The applicant clarified that no elastic-plastic evaluations, which would have skewed the ranking results, were found for these components. The applicant determined that, based on analytical experience and engineering judgment, the relative design report CUF values of the components indicate that any transient lumping used in the various analyses did not skew the screening and ranking results. Thus, a consistent technical basis has been used to perform the EAF screening and identify appropriate EAF monitoring locations.

The staff identified four assumptions in the applicant's response to Part (c) of RAI 4.3-20 by letter dated October 11, 2012, and in its response to Part (a) of RAI 4.3-21 (discussed below), as revised by letter dated December 13, 2012, that were made when determining the EAF locations to be monitored by the Fatigue Monitoring Program. The staff noted that the applicant has not demonstrated that the U_{en} values of its systems were calculated with the same level of rigor or conservatism. Without demonstrating that the U_{en} values share a common calculational basis, the staff noted that the resulting ranking and comparisons may not determine the appropriate EAF monitoring locations for the Fatigue Monitoring Program. Based on these issues, by letter dated March 26, 2013, the staff issued RAIs 4.3-22 through 4.3-27 requesting that the applicant provide additional information to demonstrate that the values for environmental fatigue usage in its methodology for identifying "sentinel locations" are based on a normalized scale, such that the resulting ranking and comparisons are appropriate. The staff identified this as Open Item 4.3.4-1. In the discussion that follows, RAIs 4.3-22 through 4.3-27 and the associated responses are discussed and evaluated in the closure of OI 4.3.4-1.

RAI 4.3-22 requested the applicant, for each assumption identified in the RAI responses and any other assumptions made in its EAF screening evaluation, to provide plant-specific situations that are based on the applicant's data and analyses to further justify that these assumptions would allow meaningful and valid comparisons among calculated U_{en} values at the applicant's facility.

In its response dated April 26, 2013, to RAI 4.3-22, the applicant stated its use of Assumptions #1 through #3 is limited to the same generation of analyses. The applicant also confirmed that Assumptions #1 through #4 discussed in its response represent all the assumptions made when performing the CUF and U_{en} comparison to determine EAF monitoring locations. The staff's review of Assumptions #1 through #4 is documented below.

Assumption #1. Same fatigue curve for each material was used for the analyses.

In its response dated April 26, 2013, the applicant stated that all fatigue calculations are performed to the ASME Code, although different editions were used. The response to RAI 4.3-25 (in a letter dated April 26, 2013, as discussed below) addresses how the ASME fatigue curve edition affects the fatigue results. The use of a different fatigue curve (e.g., the EAF fatigue curves from NUREG/CR-6909 for Ni-Cr-Fe steels) would be a deviation from the ASME Code, which would be recorded in the design reports. The staff noted that a comparison of CUF values calculated based on non-ASME and ASME fatigue curves would not be a direct comparison and would require additional consideration/evaluation in order to compare them on

an equivalent basis. The applicant confirmed that no non-ASME fatigue curves were used in its plant design; thus, the applicant determined that in the absence of the identification of another fatigue curve, the same ASME fatigue curve was used for all components with the same generation of analyses.

The staff finds it appropriate that the applicant considered the type of fatigue curve (i.e., ASME or non-ASME) used in the calculation of CUF values and ensured that only ASME fatigue curves were used, thus ensuring the ability to compare CUF values for locations of the same material without additional consideration/evaluation on an equivalent basis. Therefore, the staff's concern of the potential use of non-ASME fatigue curves and the comparison of CUF values calculated based on non-ASME and ASME fatigue curves without additional consideration/evaluation is resolved. Further discussion regarding the staff's review of the ASME Code fatigue curves is discussed in its evaluation of RAI 4.3-25.

Assumption #2. The analyses have been performed using the same level of rigor.

In its response to RAI 4.3-22 dated April 26, 2013, the applicant stated that the most important aspect of the "level of rigor" is whether an elastic or elastic-plastic fatigue analysis was performed and that any deviation from the typical elastic analysis is identified in the design report. The applicant explained that when more rigorous elastic-plastic fatigue analyses are performed, this is considered in the review; however, the screening is performed using the results of the elastic fatigue analysis in order to keep the same "level of rigor" in the comparison. The staff noted that the methods to perform an elastic-plastic fatigue analysis and an elastic fatigue analysis are very distinct from each other; thus, it is inappropriate to compare CUF values calculated from these two types of analyses. The staff also noted that other aspects that may impact the "level of rigor" in fatigue analyses are the input transients, and whether they are design, actual, or lumped transients, which are addressed in Assumption #3. The applicant confirmed that the screening is based on the design-basis analyses which only use the design transients. The staff finds it appropriate that the applicant consistently considered CUF values that were calculated using an elastic fatigue analysis to ensure that screening and ranking results were not artificially skewed based on the distinct calculational methods in an elastic-plastic fatigue analysis. Thus, the staff finds its concern associated with fatigue analyses using a different "level of rigor" is resolved.

Assumption #3. Any transient lumping used in the various analyses has not skewed the screening and ranking results.

In its response to RAI 4.3-22 dated April 26, 2013, the applicant stated that transient lumping might promote some fatigue usage values to higher rankings and result in these components being skewed upward. However, the applicant clarified that this skewing will not affect the identification of the leading component, either because (1) all of the components used the same lumping set (particularly when comparing components from the same design report) or (2) the leading component does not use lumping, thus any lumping in the bounded location will not affect the top of the ranking. The staff noted that its concern is not associated with whether or not the applicant's fatigue analyses used transient lumping. Rather, the staff's concern is associated with whether or not the applicant compared CUFs that were calculated with lumped transients with CUFs that were not calculated with lumped transients.

In order to verify that that the lumping will not affect the top of the rankings in each thermal zone, the applicant reviewed all bounded locations. Based on the applicant's review it was determined that AF monitoring locations were either based on a "common basis stress evaluation," which is not affected by any lumping, or all of the components being compared

used the same lumping set, which also does not affect the ranking. Since a review was performed to confirm that in all situations in which one location bounds another that any transient lumping was consistent between the locations, the staff finds that its concern that the comparison of CUF values that were calculated with or without transient lumping may impact screening and ranking results is resolved. The staff's review of the applicant's implementation of a "common basis stress evaluation" for determining EAF monitoring location is documented below in its evaluation of the applicant's response to RAI 4.3-23.

Assumption #4. The comparison of CUFs across multiple thermal zones is valid.

In its response to RAI 4.3-22 dated April 26, 2013, the applicant stated that the examples provided in its response to RAI 4.3-21, Part (a), are the only instances where one thermal zone bounds another. The staff's review of each of these examples is discussed below.

Example #1 involved the "pressurizer safety and relief valve piping" thermal zone bounding the "pressurizer upper head" thermal zone. The applicant provided its justification for this example; however, the applicant ultimately included the locations for the "pressurizer upper head" thermal zone to the list of locations in LRA Table 4.3-7 that will be monitored for EAF during the period of extended operation. The staff confirmed that the stainless steel pressurizer upper instrument nozzle and low-alloy steel pressurizer shell at support lug were added to LRA Table 4.3-7 as locations that will be monitored for EAF by the Fatigue Monitoring Program. The staff finds the addition of the stainless steel pressurizer upper instrument nozzle and low-alloy steel pressurizer shell at support lug acceptable because both locations were included for EAF monitoring instead of relying on bounding different locations associated with the pressurizer thermal zones.

Example #2 involved the replacement steam generator (RSG) "tubesheet" thermal zone bounding the "replacement steam generator primary head" thermal zone. The applicant stated that the low-alloy steel RSG primary manway drain tube in the RSG primary head thermal zone is bounded by the low-alloy steel RSG tubesheet (continuous region) in the tubesheet thermal zone. The applicant confirmed that both thermal zones were analyzed within the same generation of analysis during the RSG design project, which was performed by the same vendor. The applicant also confirmed that the transients used in these analyses were not lumped; these locations are exposed to the same transients in terms of number and severity; consistent material properties were used, and the same ASME Code edition was used. The staff finds this example in which the low-alloy steel RSG primary manway drain tube is bounded by the low-alloy steel RSG tubesheet (continuous region) acceptable because the variables that can affect the CUF value (e.g., transient lumping, transient occurrences and severity, material properties, and ASME Code edition) were consistent between the analyses for these locations. Thus, the staff finds that it is reasonable to rank the CUF values for these components and determine the bounding location for EAF monitoring.

Based on its review, the staff finds the applicant has addressed its concerns associated with comparing and determining EAF monitoring locations based on U_{en} values because the applicant justified, as discussed above in Assumptions #1 to #4, that the comparison of components shared a common calculational basis. RAI 4.3-20, Part (c), RAI 4.3-21, Parts (a) through (c), and RAI 4.3-22 are resolved.

Finally, by letter dated September 6, 2012, the staff requested the applicant in RAI 4.3-20, Part (d) to provide the basis for not considering the fatigue curve in Figure A.3 of NUREG/CR-6909 for screening and determining an EAF monitoring location if it was not used in determining the F_{en} of Ni-Cr-Fe steels.

In its response dated October 11, 2012, as amended by letter dated December 13, 2012, the applicant stated the EAF screening was revised to not use the equations in NUREG/CR-6909 for the F_{en} for Ni-Cr-Fe; instead, the revised screening calculation would use NUREG/CR-5704 to compute F_{en} values for Ni-Cr-Fe material while using ASME Code determined CUF values. The applicant clarified that this approach to use NUREG/CR-5704 for nickel alloy components is only for the EAF screening and that further refinement of these factors can be achieved in future analysis using the methods in NUREG/CR-6909 for Ni-Cr-Fe material for individual components. The F_{en} formula in NUREG/CR-5704 relied on the austenitic steels ASME design fatigue curves that are also applicable to nickel alloys; thus, the staff noted that NUREG/CR-5704 is also applicable to nickel alloys.

The staff finds it acceptable that NUREG/CR-5704 was used to determine an average F_{en} value for nickel alloy components for the purposes of EAF screening because (1) the F_{en} formula in NUREG/CR-5704 is applicable to nickel alloys, (2) F_{en} values calculated with NUREG/CR-5704 yield more conservative F_{en} values when compared to F_{en} values calculated with NUREG/CR-6909, (3) use of the ASME fatigue curve instead of the fatigue curve in NUREG/CR-6909 for nickel alloys ensures the EAF screening and ranking was performed on a consistent basis. In addition, the staff finds it appropriate that during the refinement of U_{en}, as part of the Fatigue Monitoring Program, the applicant will use NUREG/CR-6909 to calculate the U_{en} value, which is consistent with the GALL Report. RAI 4.3-20, Part (d), is resolved.

The staff also issued RAI 4.3-21, Parts (a) through (i), by letter dated September 6, 2012, requesting that the applicant, for each screening method described in the LRA, provide two examples of the method used to reduce the initial screening list, including a reason that this method was appropriate and conservative for each situation. The applicant was also requested to justify each screening method and specifically address any factors or criteria that are applicable when implementing screening methods.

The staff reviewed the applicant's response to RAI 4.3-21, Parts (a) through (c) (in the applicant's letter dated October 11, 2012), and noted that the applicant's response to RAI 4.3-22, in a letter dated April 26, 2013, specifically related to "Assumption #4," addresses the staff's concerns identified in RAI 4.3-21, Parts (a) through (c), related to comparing CUF values across multiple thermal zones. Thus, the staff's evaluation of the applicant's "One Thermal Zone can bound another Thermal Zone in a System" method for reducing the initial screening list for EAF monitoring is documented in the evaluation of RAI 4.3-22 (see Assumption #4 above).

In addition, in its response to RAI 4.3-21 by letter dated October 11, 2012, as amended by letter dated December 13, 2012, the applicant provided the only examples in which it used the other two of its screening methods, which include that "One material in a Thermal Zone can bound other materials in the same Thermal Zone" and "One material in a Thermal Zone can bound other materials in another Thermal Zone," to reduce the initial screening list for EAF monitoring. By letter dated April 26, 2013, the applicant amended LRA Section 4.3.4 so that these two methods were no longer used in its evaluation for reducing the initial screening list for EAF monitoring. The staff confirmed that locations that were associated with these examples for reducing the initial screening list have been added as EAF monitoring locations in LRA Table 4.3-7, as amended by letter dated April 26, 2013. Thus, the staff finds RAI 4.3-21, Parts (d) through (i) and the associated applicant responses are no longer applicable and are moot.

In its letter dated December 13, 2012, in response to RAI 4.3-21, the applicant revised LRA Section 4.3.4 stating that a location that can be shown to be bounded by another location on a "common basis stress evaluation" may be removed from the EAF monitoring list. The applicant provided a qualitative explanation that this judgment relies upon the comparison of transients in terms of severity and/or number of occurrences. In order for the staff to determine whether the "common basis stress evaluation" is appropriate or valid for the applicant's facility, additional information is needed related to the scope, parameters considered, and assumptions involved. By letter dated March 26, 2013, the staff issued RAI 4.3-23 requesting the applicant to provide additional information regarding the process used for the "common basis stress evaluation" and whether plant design, material fabrication, and geometry of components were considered. In addition, the applicant was requested to justify any use of a "common basis stress evaluation" other than in the chemical and volume control system (CVCS).

In its response dated April 26, 2013, the applicant confirmed that the "common basis stress evaluation" is based on transient severity, including analytical features (ASME Section III NB-3600 versus NB-3200), and number of transient occurrences. In addition, the applicant stated that other conditions, such as the dissolved oxygen level and strain-rate, are based on consistent assumptions and are used to calculate the F_{en} component of U_{en}. The applicant explained that the "common basis stress evaluation" is based on a qualitative assessment of the stresses applied to the components, which must be the same material, and these evaluations are appropriate to its plant because all of the CUF values were taken from the design reports that incorporate plant-specific geometric characteristics and transients. The staff's evaluation of each instance the applicant used a "common basis stress evaluation" to identify an EAF monitoring location is documented below.

By letter dated December 13, 2012, the applicant amended LRA Section 4.3.4 to provide an example where a "common basis stress evaluation" was performed in the CVCS. The applicant stated that the charging nozzle, which experiences transients in the CVCS and reactor coolant system (RCS) thermal zones, will bound the fatigue behavior of other CVCS locations. The applicant explained that the charging nozzle CVCS transients have a reflood feature where the nozzle temperature would experience a step increase from the CVCS transient temperature to the reactor coolant system cold leg temperature. In addition, the applicant confirmed that no other CVCS component experiences this reflood shock from the cold leg. The staff finds it reasonable that CVCS locations are bounded by the charging nozzles because (1) the charging nozzle experiences significant temperature variations from the reflood shock that are not experienced in all other CVCS components, and (2) the charging nozzle experiences transients from two thermal zones whereas all other CVCS components experience transients only from the CVCS thermal zone. Thus, the fatigue usage accumulated at the charging nozzle will be greater than that of all other CVCS components.

The applicant stated in its response to RAI 4.3-23 that two additional locations outside the CVCS system used a "common basis stress evaluation." The staff's evaluation of these additional locations is documented below.

The applicant stated that the stainless steel RCS hot leg piping is bounded by its attached nozzles based on a "common basis stress evaluation." The applicant clarified that the attached nozzles are subjected to transients from two thermal zones (the hot leg thermal zone and one other thermal zone). Specifically, the surge line thermal zone affects the stainless steel hot leg surge nozzle; the hot leg safety injection thermal zone affects the stainless steel hot leg safety injection nozzles; and the residual heat removal (RHR) hot leg thermal zone affects the stainless steel RHR hot leg nozzles. The applicant stated that all other hot leg locations are

subjected only to the hot leg thermal zone transients. The staff finds it reasonable that the stainless steel RCS hot leg piping is bounded by the attached stainless steel nozzle components and that these three nozzle components are included as an EAF monitoring location because the nozzle components experience transients from an additional thermal zone other than the hot leg thermal zone; thus, the fatigue usage accumulated at the nozzle components will be greater than that of the attached stainless steel RCS hot leg piping.

The applicant also stated that the stainless steel pressurizer spray nozzle bounds the stainless steel pressurizer spray piping and the stainless steel spray line nozzle at the cold legs based on a "common basis stress evaluation."

For the first instance, the applicant stated that the limiting location in the pressurizer spray line piping thermal zone is at the pressurizer spray nozzle, which is now under a structural weld overlay (SWOL). This SWOL covers both the nozzle-to-safe-end dissimilar metal butt-weld and the safe-end-to-piping stainless steel butt-weld; the applicant also stated that the highest fatigue locations are under this overlay and are qualified for fatigue by a crack growth analysis. The staff's evaluation of the applicant's SWOL TLAA is documented in SER Section 4.7.2.2. The applicant stated that the next highest fatigue location is located in the spray piping near the toe of the overlay, and the SWOL analysis states that the current fatigue analysis of the spray nozzle without the SWOL is conservative relative to the toe of the SWOL on the piping. The applicant stated that the pressurizer spray line piping's next limiting location is in the auxiliary spray line and the staff confirmed that this location is already identified as an EAF monitoring location. The staff finds it reasonable that the stainless steel pressurizer spray line piping is bounded by the attached stainless steel pressurizer spray nozzle because nozzles typically experience temperature and pressure changes due to the transients that are greater than connected piping, and the SWOL analysis determined the nozzle CUF was conservative when compared to the CUF of the toe of the SWOL on the piping.

For the second instance, the applicant stated that the pressurizer spray nozzle will experience transients from two thermal zones (pressurizer upper head and spray line piping) and will be subjected to significant thermal transients during pressurizer spray initiation-and-termination and during auxiliary spray initiation-and-termination. In addition, the spray events are much less severe at the spray line nozzle at the cold legs as the temperature at the nozzle remains constant during a spray event and will primarily experience RCS transients (e.g., heatup and cooldown). The staff finds it reasonable that the stainless steel spray line nozzle at the cold legs is bounded by the stainless steel pressurizer spray nozzle because the pressurizer spray nozzle experiences significant temperature variations from pressurizer spray and auxiliary spray initiations and terminations within the pressurizer upper head and spray line piping thermal zones, whereas the temperature at the spray line nozzle at the cold legs remains constant during a spray event. Thus the fatigue usage accumulated at the pressurizer spray nozzle will be greater than that of the spray line nozzle at the cold legs.

The applicant explained that the RCS 2-inch crossover leg loops 1 & 2 drain nozzles were previously bounded by the charging nozzle based on a "common basis stress evaluation." However, the applicant deleted this because there is not a sufficient overlap of the transients. Therefore, the RCS 2-inch crossover leg loops 1 & 2 drain nozzles were added as an EAF monitoring location. The staff confirmed that the RCS 2-inch crossover leg loops 1 & 2 drain nozzles were added to LRA Table 4.3-7.

Based on its review, the staff finds the applicant's "common basis stress evaluation" reasonable because (1) it provides a comparison of two locations of the same material based only on

transient severity and number of transient occurrences in order to provide a qualitative indication of which location is more sensitive to metal fatigue, and (2) this evaluation was based on the applicant's plant-specific design reports, which incorporate system geometric characteristics and transients. In addition, the staff finds the applicant demonstrated for its plant-specific design that the implementation of the "common basis stress evaluation," only for those instances identified above, was reasonable in determining a bounding location for EAF monitoring during the period of extended operation. RAI 4.3-23 is resolved.

In its response dated October 11, 2012, to Part (d) of RAI 4.3-21, as revised by letter dated December 13, 2012, the applicant provided an example supporting one of its screening principles that one material can bound other materials in the same thermal zone. The applicant indicated that those plant-specific locations with U_{en} greater than 1.0 will be evaluated further using the same methods as those to remove conservatisms for NUREG/CR-6260 locations described in LRA Section 4.3.4. The staff noted, however, that the applicant has not justified that the low-alloy steel components would remain bounded by the stainless steel components after the EAF analysis has been refined to reduce the U_{en} of the stainless steel components. In addition, the applicant has not explained how — nor justified that — the refinement of a higher U_{en} in LRA Table 4.3-6 of one material would ensure the reduction of U_{en} for a bounded location of another material. By letter dated March 26, 2013, the staff issued RAI 4.3-24 requesting the applicant justify that the refinement of a higher U_{en} in LRA Table 4.3-6 of one material would ensure the reduction of the U_{en} for a bounded location of another material, such that the conclusion that one material bounds other materials in the same thermal zone will remain valid.

In its response to RAI 4.3-24 by letter dated April 26, 2013, the applicant stated that the example provided in the RAI 4.3-21, Part (d), response dated December 13, 2012, is the only instance where a location of one material bounds the location of another material. In this case, the staff noted that the stainless steel pressurizer instrument nozzle bounds the low-alloy steel pressurizer shell at support lug in the pressurizer upper head thermal zone. The applicant stated that, in order to ensure that the refinement of a higher U_{en} of one material will bound the U_{en} of another material, both locations were added to the list of EAF monitoring locations in LRA Tables 4.3-6 and 4.3-7. The staff confirmed that the pressurizer instrument nozzle and pressurizer shell at support lug are identified in LRA Table 4.3-7 as EAF monitoring locations. The staff finds the inclusion of the stainless steel pressurizer instrument nozzle and low-alloy steel pressurizer shell at support lug as EAF monitoring locations acceptable because the applicant included locations from applicable materials for the thermal zones associated with the pressurizer. The staff noted that the applicant also revised LRA Section 4.3.4 such that the provision of "one material in a thermal zone can bound other materials in the same thermal zone" was removed.

In its response to RAI 4.3-24, the applicant also stated that the Fatigue Monitoring Program will be enhanced such that the EAF monitoring locations, when refined, will be revisited to confirm that the bounding environmentally assisted fatigue susceptible locations are updated appropriately and remain bounded consistent with the refined analysis. The applicant stated that the commitment in LRA Table A4-1, No. 31, and LRA Section B3.1 are updated to confirm that the bounding environmentally assisted fatigue susceptible locations are updated appropriately and remain bounded consistent with the refined analysis. By letter dated August 2, 2013, the applicant revised its response to RAI 4.3-24 and LRA Section A2.1 to state that the sentinel location analysis, when refined, will be revisited to confirm that the bounding environmentally assisted fatigue susceptible sentinel locations are updated appropriately and remain bounded consistent with the refined analysis. The staff finds this revision to LRA Section A2.1 acceptable because the FSAR supplement explicitly provides a summary

description as to the actions the applicant will take to confirm that the environmentally assisted fatigue susceptible locations, as provided in LRA Table 4.3-7, are updated appropriately and remain bounded consistent with any analysis performed to refine U_{en} values less than 1.0 for these EAF monitoring locations.

Based on its review, the staff finds the applicant response to RAI 4.3-24, as amended by letter August 2, 2013, acceptable because (1) the applicant will no longer use the screening principle that one material can bound other materials in the same thermal zone, and (2) the applicant's Fatigue Monitoring Program, when enhanced, will ensure that bounding EAF monitoring locations are updated appropriately and remain bounded consistent with the refined analysis. RAI 4.3-24 is resolved.

The staff noted that the elastic modulus for the austenitic stainless steel fatigue curve in Figure I-9.2 of the ASME Code Section III, Appendix I, changed from 26×10^6 psi in the 1980 edition to 28.3×10^6 psi in the 1983 edition. It is not clear to the staff whether this change in the stainless steel material property in the aforementioned ASME Code Section III editions has been considered in the U_{en} comparison by the applicant.

By letter dated March 26, 2013, the staff issued RAI 4.3-25 requesting the applicant identify all the stainless steel components that were designed to ASME Code editions that were issued after the 1980 edition. The applicant was also requested to clarify whether any stainless steel component designed after the 1983 edition of the ASME Code has been used to bound another stainless steel component that was designed to the 1980 or earlier ASME Code edition.

In its response to RAI 4.3-25 by letter dated April 26, 2013, the applicant stated that all ASME Class 1 stainless steel components in its plant were analyzed to ASME Code editions that are pre-1980 except for the pressurizer lower head. The applicant also stated that the pressurizer lower head was evaluated as a unique thermal zone with one EAF monitoring location identified and that location is not used to bound any locations outside the pressurizer lower head thermal zone.

Based on its review, the staff finds the applicant response to RAI 4.3-25 acceptable because the applicant demonstrated that the differences in the fatigue design curve and elastic modulus between the 1980 and 1983 editions of the ASME Code, Section III, did not impact the comparison of U_{en} values for stainless steel locations since any comparisons were consistently made to fatigue analyses performed to the 1980 edition or the 1983 edition. RAI 4.3-25 is resolved.

In its response to RAI 4.3-21, Part (d), by letter dated October 11, 2012, as amended by letter dated December 13, 2012, the applicant revised LRA Table 4.3-7 indicating two Ni-Cr-Fe components (RPV bottom head instrument tubes and RSG tube-to-tubesheet connection) as EAF monitoring locations. The staff noted that LRA Table 3.1.2-3 identifies nickel alloy pressurizer safe ends that are exposed to the reactor coolant environment with the aging effects of cumulative fatigue damage. The staff did not identify any reference to these nickel alloy pressurizer safe ends as EAF monitoring locations in LRA Table 4.3-7; thus, it was not clear to the staff how these components were bounded by other stainless steel pressurizer locations identified in LRA Table 4.3-7.

By letter dated March 26, 2013, the staff issued RAI 4.3-26 requesting that the applicant identify the nickel alloy components in the pressurizer safe ends and demonstrate how the nickel alloy locations have been bounded by other pressurizer locations identified in LRA Table 4.3-7.

In its response to RAI 4.3-26 by letter dated April 26, 2013, the applicant stated that the nickel alloy locations in the pressurizer are in the weld materials associated with the pressurizer safety and relief nozzles, the pressurizer spray nozzle, and the pressurizer surge nozzle. The applicant also stated that all of these locations in the nozzles have had a preemptive SWOL applied over the nickel alloy material, that these SWOLs are supported by fracture mechanics analyses, and that periodic inspections are consistent with ASME Code Section XI as the means to address aging in the overlaid welds.

The staff noted that an SWOL effectively mitigates the effect of metal fatigue because any initiated crack due to metal fatigue will not grow beyond the critical crack size before the inspection interval determined by the fracture mechanics analyses. Thus, the staff finds that inspections will be performed at sufficient intervals, which are supported by the fracture mechanics analyses, before the component can no longer perform its pressure boundary intended function. In addition, the staff noted that, since the SWOLs have been applied to these components, the overlay maintains the pressure boundary of the component instead of the nickel alloy material. The staff evaluation of the applicant's TLAA associated with the pressurizer SWOLs is documented in SER Section 4.7.2.2. The staff finds it reasonable that environmentally assisted fatigue is not an aging effect requiring management for these nickel alloy safe ends since their intended function to maintain the reactor coolant pressure boundary is now being performed by the SWOLs, which are being managed for age-related degradation.

Based on its review, the staff finds the applicant's response to RAI 4.3-26 acceptable because the applicant clarified that the aging effect of cumulative fatigue damage for the nickel alloy pressurizer safe end components is managed as part of the SWOLs by the facture mechanics TLAA and environmentally assisted fatigue is not applicable. RAI 4.3-26 is resolved.

LRA Section 4.3.4, as amended by letter dated December 13, 2012, also indicates that the 60-year projected U_{en} is 0.74 for the safety injection nozzle and the 60-year projected cycle counts are the same as the numbers of cycles to date for three transients assumed in the EAF analysis. The staff noted that, when using the CBF monitoring method, the incremental fatigue usage for each transient can be accumulated to provide a fatigue usage as the components are being monitored during the period of extended operation. Furthermore, the incremental fatigue usage was supported by an ASME Code Section III fatigue analysis with an assumed number of occurrences for each transient. However, the staff noted the incremental fatigue usage may change after the number of occurrences of a transient had exceeded that assumed in the fatigue analysis due to the transient-pairing provision in ASME Code Section III Paragraph NB-3222.4(e)(5).

By letter dated March 26, 2013, the staff issued RAI 4.3-27, requesting that the applicant clarify how the incremental fatigue usage and fatigue accumulation will be tracked when the cycle count is beyond those assumed in the fatigue analysis and justify that, prior to reaching the "fatigue-usage action limit," incremental fatigue usage for additional occurrences beyond those assumed in the fatigue analysis will be calculated in accordance with the ASME Code. The applicant was also requested to clarify whether the safety injection nozzle is the only location that was analyzed for the number of transient cycles to date and justify that the implementation of a "fatigue-usage action limit" would ensure that corrective action will be initiated before exceeding the design limit.

In its response to RAI 4.3-27 by letter dated April 26, 2013, the applicant stated that the safety injection nozzle is the only CBF monitored location which used the number of transient cycles to date. The applicant explained that CBF is not limited by the number of cycles assumed in the

ASME Code fatigue analysis because this monitoring method utilizes the stress intensity for each transient, which are generated with the ASME Section III methods. The applicant clarified that the stress intensities are paired in accordance with ASME Code Section III Paragraph NB-3222.4(e)(5), but the pairing is performed according to the actual numbers of transients that have occurred and not necessarily identical to the pairing order in the design analysis.

The staff noted that the use of CBF is effectively calculating a fatigue usage in accordance with ASME Code Section III Paragraph NB-3222.4(e)(5) on an ongoing basis, which is consistent with the recommendations in the "detection of aging effects" program element of GALL Report AMP X.M1, which states that the program provides for updates of the fatigue usage calculations on an as-needed basis. Thus, the staff finds that the applicant clarified how the incremental fatigue usage and fatigue accumulation will be tracked and determined it is consistent with the recommendations in GALL Report AMP X.M1.

The staff also noted that the premise of CBF is to calculate a fatigue usage based on those stress intensities, but not the assumed numbers of cycles, which were calculated in the ASME Code fatigue analysis. The staff noted that since the number of cycles assumed in the analysis was not relied on in the CBF monitoring method, the staff's concern regarding whether the fatigue usage calculation will be determined consistent with the transient-pairing provision in ASME Code Section III Paragraph NB-3222.4(e)(5) is resolved.

The applicant stated that the cycle count will only be allowed to increase beyond the number assumed in the fatigue analysis if the CUF and/or the U_{en} can be assured to be less than the "fatigue-usage action limit" using the CBF monitoring method. Furthermore, the applicant explained that these incremental fatigue usage values are calculated and tracked against the "fatigue-usage action limit" to ensure corrective action is taken prior to fatigue accumulation exceeding the ASME Code allowable fatigue limit of 1.0.

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 described in the program description and scope of program. Thus, the staff finds it conservative that the applicant set the fatigue-usage action limit such that actions are taken before the design limit of 1.0 is exceeded and is consistent with the recommendations in GALL Report AMP X.M1.

Based on its review, the staff finds the applicant response to RAI 4.3-27 acceptable because the applicant (1) clarified that the CBF monitoring method and calculation of the fatigue usage does not rely on the numbers of cycles assumed in the analysis, (2) explained that CBF monitoring method is not inconsistent with the provision in ASME Code Section III, and (3) justified that the implementation of a "fatigue-usage action limit" for CBF would ensure that corrective action will be initiated before exceeding the design limit of 1.0. RAI 4.3-27 is resolved.

Based on its review, as described above, the staff finds the applicant has justified its approach and its determination of locations that require monitoring for environmentally assisted fatigue of the reactor coolant pressure boundary during the period of extended operation. Thus, Open Item 4.3.4-1 is closed.

LRA Section 4.3.4, as amended by letter dated May 3, 2012, indicates that those non-NUREG/CR-6260 locations with an EAF CUF greater than 1.0 will be evaluated further using the same methods as those used to refine the EAF CUF for the NUREG/CR-6260 locations described above. The staff noted that the methods used to refine the EAF CUF are

not restricted to only those locations identified in the NUREG/CR-6260 and the staff's review of these methods are described above. The LRA states that the results of these final analyses for the non-NUREG/CR-6260 locations will be incorporated into the Fatigue Monitoring Program by either counting the transients assumed or incorporate the stress intensities into a CBF ability of the program. The staff's review of the of cycle counting method, CBF and SBF methods are discussed in its review of the Fatigue Monitoring Program as documented in SER Section 3.0.3.2.22. The staff determined that the cycle counting method will ensure a fatigue analysis remains valid by ensuring the assumptions in the analysis are not exceeded. In addition, the staff determined that the CBF and SBF monitoring methods will ensure that the accumulated fatigue usage, including the effects of reactor coolant, of a component resulting from transient occurrences will not exceed the design limit of 1.0.

The staff finds that the applicant has demonstrated, in accordance with 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. Additionally, the applicant's disposition 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 Fatigue Monitoring 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 FSAR Supplement

LRA Section A3.2.3, as amended by letter dated October 17, 2013, provides the FSAR supplement summarizing the environmentally assisted fatigue evaluations for NUREG/CR-6260 locations and non-NUREG/CR-6260 reactor coolant pressure boundary locations. In addition, LRA Section A3.2.3 states that reactor vessel internals locations with fatigue usage calculations will be evaluated for the effects of the reactor water environment. The staff noted that LRA Section A3.2.3 clearly identifies the NUREG reports, which are consistent with those identified in the GALL Report, that will be used to address environmentally assisted fatigue for reactor coolant pressure boundary and reactor vessel internal 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 the reviewer verifies that the applicant has provided information to be included in the FSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the FSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2 and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the environmentally assisted fatigue evaluations for NUREG/CR-6260 locations and non-NUREG/CR-6260 reactor coolant pressure boundary locations, as required by 10 CFR 54.21(d).

4.3.4.4 Conclusion

On the basis of its review, the staff concludes that the applicant has acceptably demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of environmentally assisted fatigue on the intended functions of the monitored NUREG/CR-6260 locations will be adequately managed by the Fatigue Monitoring Program for the period of extended operation. In addition, the staff concludes that the applicant has acceptably demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of environmentally assisted fatigue on the intended functions of the monitored non-NUREG/CR-6260 reactor coolant pressure boundary locations will be adequately managed by the Fatigue Monitoring Program for the period of extended

operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the environmentally assisted fatigue evaluations, 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 Section III Class

4.3.5.1 Summary of Technical Information in the Application

LRA Section 4.3.5 states that piping within the scope of license renewal "that is designed to American National Standards Institute (ANSI) B31.1 or ASME Code Section III Class 2 and 3 requires the application of a stress range reduction factor to the allowable stress range (expansion and displacement) to account for thermal cyclic conditions." The LRA also states that "[n]one of ANSI B31.1 or the ASME Code Section III Subsections NC and ND for Class 2 and 3 piping invokes fatigue analyses. If the number of full-range thermal cycles is expected to exceed 7,000, these codes require the application of a stress range reduction factor to the allowable stress range for expansion stresses (secondary stresses)."

With the exception of reactor coolant sample lines, these piping and components within the scope of license renewal clearly do not operate in a cycling mode that would expose the piping to more than three thermal cycles per week (i.e., to more than 7,000 cycles in 60 years.) For the reactor coolant sample lines, a survey of plant piping systems found that some reactor coolant sample lines may be subject to more than 7,000 thermal cycles. Review of operating practice at Callaway indicates that RCS samples are taken weekly from the hot leg during operation. The LRA states that, therefore, none of the lines associated with this sample location will exceed 7,000 cycles during the period of extended operation.

The applicant dispositioned the TLAA for the existing analyses of ANSI B31.1 or ASME Code Section III Class 2 and 3 piping within the scope of license renewal for which the allowable range of secondary stresses depends on the number of assumed thermal cycles, in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

4.3.5.2 Staff Evaluation

The staff reviewed LRA Section 4.3.5 and the TLAA for ANSI B31.1 or ASME Code Section III Class 2 and 3 piping for which the allowable range of secondary stresses depends on the number of assumed thermal cycles to verify, in accordance with 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 of 10 CFR 54.21(c)(1)(i), consistent with the review procedures in SRP-LR Section 4.3.3.1.2.1. 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 4.3.5 provides a list of several systems and states that these systems are subject to thermal fatigue effects and were therefore included in the aging management review (AMR) results presented in LRA Section 3. Specifically, the main feedwater system and boron recycle system were included as part of this list of systems subject to thermal fatigue effects. However, the staff noted that LRA Tables 3.4.2-3 and 3.3.2-28 did not provide AMR results for components subject to "cumulative fatigue damage." It is also not clear whether there are

additional systems and components that are subject to an AMR for “cumulative fatigue damage,” in accordance with 10 CFR 54.21(a)(1), and were not included in the LRA.

By letter dated September 6, 2012, the staff issued RAI 4.3-10 requesting the applicant to provide the appropriate AMR results for components subject to thermal fatigue effects for the main feedwater system and boron recycle system and to justify any AMR results with "cumulative fatigue damage" as an aging effect that were excluded.

In its response to RAI 4.3-10 dated October 11, 2012, the applicant revised LRA Tables 3.3.2-28 and 3.4.2-3 to include the applicable AMR items for piping components subject to the thermal effects of fatigue and confirmed that there were no other AMR items that needed to be added to the LRA. The staff noted that LRA Section 4.3.5 states that the applicant performed a review to identify components that may be subject to significant thermal fatigue effects that were then included in the AMR results. In its RAI response, the applicant stated that systems or portions of systems with low operating temperatures are not subject to significant thermal fatigue effects. The staff finds this reasonable because the differences in fluid temperature between operating temperatures and the minimum exposure temperature for these plant systems would not induce stresses that cause fatigue damage.

The staff finds the applicant’s response acceptable because the LRA was revised to include AMR items subject to thermal fatigue, in accordance with 10 CFR 54.21(a)(1), and the applicant sufficiently justified, as described above, that systems with low operating temperatures are not subject to fatigue damage. The staff’s concern described in RAI 4.3-10 is resolved.

LRA Section 4.3.5 states that, with the exception of reactor coolant sample lines, piping and components within the scope of license renewal do not operate in a cycling mode that would expose them to more than 7,000 cycles in 60 years. The staff noted that transient cycles that are likely to produce full-range thermal cycles in balance-of-plant Class 2, 3, and B31.1 piping within the scope of license renewal, with the exception of reactor coolant sample lines, are plant heatups, plant cooldowns, and reactor trips. The staff also noted that these same plant systems may be affected by temperature variations that are coincident with other design transients for the plant that can cause part-range thermal cycles.

The staff reviewed the number of occurrences for plant transients expected for 60 years of operation provided in LRA Table 4.3-2 to ensure the full thermal range transient cycle limit of 7,000 will not be exceeded. The staff noted that even if the part-range thermal cycles are conservatively assumed to be full-range thermal cycles, the total number of design basis thermal events expected to occur in a 60-year life is approximately 1,600 cycles. The staff’s review of the applicant’s 60-year projection methodology is documented in SER Section 4.3.1.2.2. Thus, based on its review, the staff finds it reasonable that the full-range thermal 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 and includes margin to account for unanticipated transient occurrences during the period of extended operation.

LRA Section 4.3.5 states that a review of FSAR Table 9.3-3 SP and the Callaway chemistry schedule identified that the only sample piping within the scope of license renewal that meets the temperature screening criteria, and could possibly exceed 7,000 cycles, is the RCS hot leg sample piping. The LRA also states that a review of operating practice at Callaway indicates that RCS samples are taken weekly from the hot leg during operation.

The staff reviewed FSAR Table 9.3-3 SP and noted that it provides the "typical sampling frequency" for the primary sampling systems. Specifically, the table lists a frequency of three per week or one per week for the RCS hot legs sample (loop 1 or 3). Based on information presented in the LRA and in FSAR Table 9.3-3 SP, the sampling frequency of the RCS hot legs sample (loop 1 or 3) is not clear to the staff. The FSAR indicates that the sampling frequency can be up to 3 per week, and it appears that the Callaway chemistry schedule indicates a sampling frequency of once per week.

By letter dated September 6, 2012, the staff issued RAI 4.3-11 requesting the applicant to provide the basis for the discrepancy in sampling frequency between the FSAR and the LRA. The staff also requested the applicant to confirm that, other than RCS samples taken weekly from the hot leg during operation, no other thermal cycles are likely to produce full-range or part-range thermal cycles in the sampling lines.

In its response to RAI 4.3-11 dated October 11, 2012, the applicant stated that FSAR Table 9.3-3 SP identifies 3 times per week as the "typical sampling frequency," and this is reflected in the design calculations for the hot leg sample lines, which the staff noted involved the application of a stress range reduction factor of 0.9 that permits up to 14,000 thermal cycles. The staff noted that, although the FSAR and design calculation permit a sampling frequency up to 3 times a week, the applicant confirmed that current practice at its site is to draw one sample from the hot leg sampling lines per week. The applicant stated that the sole function of the RCS hot leg sample piping is to obtain RCS hot leg samples, and it confirmed that there are no other functions or events of the nuclear sampling system that are likely to produce full-range or part-range thermal cycles.

The staff finds the applicant's response acceptable because the applicant confirmed that its practice is to sample the hot leg sample lines weekly, even though the FSAR and design calculation account for sampling the line up to 3 times per week. Additionally, the applicant confirmed that no other functions or events of the sampling line are likely to produce a full-range or part-range thermal cycles. Thus, the staff determined that approximately 3,120 cycles are expected to occur in the hot leg sample lines, which is significantly less than the 14,000 cycles permitted by the design analysis. The staff noted that there is margin to account for unexpected or unscheduled sampling cycles from the RCS hot leg sample line through the period of extended operation. The staff's concern described in RAI 4.3-11 is resolved.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the TLAAs for ANSI B31.1 or ASME Code Section III Class 2 and 3 piping for which the allowable range of secondary stresses depends on the number of assumed thermal cycles remain valid for the period of extended operation. Additionally, the applicant's analysis meets the acceptance criteria in SRP-LR Section 4.3.2.1.2.1 because, for those components subject to thermal fatigue described above, the cycle limit established in the design analysis is not expected to be exceeded based on the projected total number of full thermal range transients through the period of extended operation and includes margin to account for unanticipated transient cycles.

4.3.5.3 FSAR Supplement

LRA Section A3.2.4 provides the FSAR supplement summarizing the TLAA for ANSI B31.1 or ASME Code Section III Class 2 and 3 piping. 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 verifies that the applicant has provided information to be included in the FSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the FSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2, and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA for ANSI B31.1 or ASME Code Section III Class 2 and 3 piping, 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 has provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(i), that the TLAA for ANSI B31.1 or ASME Code Section III Class 2 and 3 piping remains valid for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.6 Fatigue Design of Spent Fuel Pool Liner and Racks for Seismic Events

4.3.6.1 Summary of Technical Information in the Application

LRA Section 4.3.6 states that the replacement spent fuel pool racks and liner are designed to the stress limits of, and analyzed in accordance with, ASME Code Section III, Division 1, Subsection NF, 1989 Edition.

These analyses are described in FSAR Section 9.1A.4.3.5.4 SP, and the spent fuel pool racks were replaced in 1999 and were analyzed for fatigue effects of one safe-shutdown earthquake (SSE) and 20 operating basis earthquakes (OBE). The analysis calculated a CUF of 0.404 and included a fatigue evaluation of the pool liner for the loads imposed by the new racks. The analysis uses the same 20 OBE, plus 1 SSE events. In addition, the analysis calculated a CUF caused by seismic events of less than 0.00352 for the liner.

The applicant dispositioned the TLAA for the fatigue design of spent fuel pool liner and racks for seismic events, in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

4.3.6.2 Staff Evaluation

The staff reviewed LRA Section 4.3.6 and the TLAA for the fatigue design of spent fuel pool liner and racks for seismic events to verify, in accordance with 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 fatigue design of spent fuel pool liner and racks for seismic events 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 noted that the two transients associated with the fatigue design of spent fuel pool liner and racks are 20 OBE and 1 SSE events, neither of which has occurred at the applicant's site at the time of the LRA submittal. The staff reviewed FSAR Section 3.7(B).1.1 SP and noted that the seismic input for its site assumed an acceleration of 0.20g in the design response spectra for both the horizontal and vertical directions of the SSE. The OBE design response spectra values were taken as 60 percent of the SSE.

Since the fatigue design of spent fuel pool liner and racks was based, in part, to the occurrence of 20 OBE events and no OBE events have occurred at the time of the LRA submittal, the staff finds that there is sufficient margin with regard to the number of OBE events cycles that the figure will not be exceeded during the period of extended operation.

The staff noted that 10 CFR 54.35, "Requirements during term of renewed license," requires, in part, that during the term of a renewed license, licensees shall be subject to, and shall continue to comply with, all NRC regulations contained in 10 CFR Part 100, "Reactor Site Criteria," and the appendices to this part. Furthermore, 10 CFR Part 100, Appendix A, "Seismic and Geoligic Siting Criteria for Nuclear Power Plants," Section V(a)(2), states that if vibratory ground motion exceeds that of the OBE, shutdown of the plant is required. Before resuming operations, the regulations require that plants must demonstrate to the staff that no functional damage has occurred to those features necessary for continued operation without undue risk to the health and safety of the public. The staff noted that since the acceleration resulting from the SSE would be greater than that of an OBE, provisions described in 10 CFR Part 100 Appendix A are applicable to any seismic events beyond the level of OBE, such as an SSE. Thus, the staff finds that the applicant's compliance with 10 CFR Part 100 and its appendices ensure that the SSCs would not experience more than one SSE event without a demonstration to the staff that no functional damage has occurred to those features necessary for continued operation without undue risk to the health and safety of the public, as required by the rule.

The staff finds it reasonable that the number of occurrences for an SSE transients would not be exceeded during the period of extended operation because (1) no SSE event has occurred at the applicant's site at the time of the LRA submittal, and (2) the applicant must comply with 10 CFR Part 100, Appendix A, Section V(a)(2).

The staff finds that the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the analyses for the fatigue design of spent fuel pool liner and racks for seismic events 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, for OBE events and an SSE event, the number of assumed transients will not be exceeded during the period of extended operation, as described above.

4.3.6.3 FSAR Supplement

LRA Section A3.2.5 provides the FSAR supplement summarizing the fatigue design of spent fuel pool liner and racks for seismic events. The staff reviewed LRA Section A3.2.5, consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the reviewer verifies that the applicant has provided information to be included in the FSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the FSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2 and is, therefore, acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the fatigue design of spent fuel pool liner and racks for seismic events, 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, in accordance with 10 CFR 54.21(c)(1)(i), that the analyses for the fatigue design of spent fuel pool liner and racks for seismic events remain valid for the period of

extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.7 Fatigue Design and Analysis of Class 1E Electrical Raceway Support Angle Fittings for Seismic Events

4.3.7.1 Summary of Technical Information in the Application

LRA Section 4.3.7 states that the design of Class 1E electrical raceway included a fatigue evaluation of the effects of operating basis and OBE and SSE loads. The LRA states that a CUF was calculated based on tests of typical designs to failure, and the number of fatigue cycles to failure was divided by a factor of safety of 1.5 to establish an allowable number of fatigue cycles for design. The LRA also states that "[t]he design assumed the number of OBE and SSE events recommended by [Institute for Electrical and Electronics Engineers] (IEEE) 344-1975, which states that the maximum number of OBE and SSE events plausible during a plant lifetime is [five] and [one], respectively."

The applicant dispositioned the TLAA for the fatigue design of Class 1E electrical raceway support angle fittings for seismic events, in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

4.3.7.2 Staff Evaluation

The staff reviewed LRA Section 4.3.7 and the TLAA for the fatigue design of Class 1E electrical raceway support angle fittings for seismic events to verify, in accordance with 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 fatigue design of Class 1E electrical raceway support angle fittings for seismic events 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 noted that the two transients associated with the fatigue design of Class 1E electrical raceway support angle fittings are 750 OBE cycles and 150 SSE cycles, neither of which has occurred at the applicant's site at the time of the LRA submittal. The staff reviewed FSAR Section 3.7(B).1.1 SP and noted that the seismic input for its site assumed an acceleration of 0.20g in the design response spectra for both the horizontal and vertical directions of the SSE. The OBE design response spectra values were taken as 60 percent of the SSE.

Since the fatigue design of Class 1E electrical raceway support angle fittings was based, in part, to the occurrence of 200 OBE cycles, and no OBE cycles have occurred at the time of the LRA submittal, the staff finds that there is sufficient margin with regard to the number of OBE cycles that the figure will not be exceeded during the period of extended operation.

The staff noted that 10 CFR 54.35 requires, in part, that during the term of a renewed license, licensees shall be subject to, and shall continue to comply with, all Commission regulations contained in 10 CFR Part 100 and the appendices to this part. Furthermore, 10 CFR Part 100 Appendix A, Section V(a)(2) states that if vibratory ground motion exceeds that of the OBE, shutdown of the plant is required. Before resuming operations, the plant must demonstrate to

the staff that no functional damage has occurred to those features necessary for continued operation without undue risk to the health and safety of the public. The staff noted that since the acceleration resulting from the SSE would be greater than that of an OBE, provisions described in 10 CFR Part 100, Appendix A, are applicable to any seismic events beyond the level of OBE, such as a SSE. Thus, the staff finds that the applicant's compliance with 10 CFR Part 100 and its appendices ensure that SSCs would not experience more than one SSE event without a demonstration to the staff that no functional damage has occurred to those features necessary for continued operation without undue risk to the health and safety of the public, as required by the rule.

The staff finds it reasonable that the number of occurrences for an SSE transients would not be exceeded during the period of extended operation because (1) no SSE event has occurred at the applicant's site at the time of the LRA submittal, and (2) the applicant must comply with 10 CFR Part 100, Appendix A, Section V(a)(2).

The staff finds that the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the analyses for the fatigue design of Class 1E electrical raceway support angle fittings for seismic events 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, for OBE events and an SSE event, the number of assumed transients will not be exceeded during the period of extended operation, as described above.

4.3.7.3 FSAR Supplement

LRA Section A3.2.6 provides the FSAR supplement summarizing the fatigue design of Class 1E electrical raceway support angle fittings for seismic events. The staff reviewed LRA Section A3.2.6, consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the reviewer verifies that the applicant has provided information to be included in the FSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the FSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2 and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the fatigue design of Class 1E electrical raceway support angle fittings for seismic events, as required by 10 CFR 54.21(d).

4.3.7.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(i), that the analyses for the fatigue design of Class 1E electrical raceway support angle fittings for seismic events remain valid for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.8 Fatigue Analyses of Class 2 Heat Exchangers

4.3.8.1 Summary of Technical Information in the Application

LRA Section 4.3.8 describes the applicant's TLAA for fatigue of its ASME Code Class 2 heat exchangers. The LRA states that the shell and tube sides of the regenerative heat exchanger, and the tube side of the letdown, letdown reheat, RHR, and excess letdown exchangers heat exchangers are designed and constructed to ASME Code Section III Class 2 1974 Edition. The

LRA also states that, as required by the design specification, thermal fatigue analyses were performed, in accordance with ASME Code Section III, Paragraph NB-3222.4, to qualify the heat exchangers to the Code design requirements. The LRA provides a list of transients that were used in the fatigue evaluations of the regenerative, letdown, and letdown reheat heat exchanger components. In addition, the LRA also provides a list of transients that were used in the fatigue evaluation of the RHR exchanger components.

The LRA provides a separate discussion of each heat exchanger as discussed below:

Regenerative Heat Exchanger. The LRA states that the fatigue analysis of the regenerative heat exchanger evaluated the tubesheets, the shell side nozzles, the tube side nozzles, and the cross shell juncture. The LRA also states that the analysis found the most limiting fatigue usage factor of 0.50 at the outlet tubesheet and the analysis of the regenerative heat exchanger also contains a fatigue waiver for the tubeside inlet nozzle. The LRA further states that the thermal analysis of the shell side nozzles, the tubeside outlet nozzle, and cross shell junction indicated these areas are not subject to fatigue. Finally, the LRA states that the transients used in this analysis will be counted by the Fatigue Monitoring Program.

The applicant dispositioned the TLAA for the fatigue design of the regenerative heat exchanger in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of metal fatigue on the intended functions will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

Letdown Heat Exchanger. The LRA states that the fatigue analysis for the letdown heat exchanger indicated a maximum CUF of 1.84 for the flange and is the result of a recent reanalysis to account for operation with a letdown flow of 140 gallons per minute (gpm). The LRA discusses the evaluation performed by the applicant to reduce the 60-year CUF to 0.894. The fatigue analyses of the other components in the letdown heat exchanger included the tubesheet, tube side nozzles, and the studs. The LRA states that these components have CUFs of 0.910, 0.843, and 0.635, respectively. The LRA discusses the evaluation performed by the applicant that increases the CUF to 0.995, 0.880, and 0.696 for these components through the period of extended operation.

The applicant dispositioned the TLAA for the fatigue design of the letdown heat exchanger 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.

Letdown Reheat Heat Exchanger. The LRA states that the fatigue analysis for the letdown reheat heat exchanger indicated a maximum CUF of 4.431 for the studs and is the result of a recent reanalysis to account for operation with a letdown flow of 140 gpm. The LRA discusses the evaluation performed by the applicant to reduce the CUF to 0.503. The fatigue analysis of the letdown reheat heat exchanger evaluated the shell and tube side nozzles and the tubesheet. The LRA states that these components have maximum CUFs of 0.054 and 0.47, respectively. The LRA discusses the evaluation performed by the applicant that increases the CUFs to 0.57 for the tubesheet and 0.0563 for the tube side nozzles.

The applicant dispositioned the TLAA for the fatigue design of the letdown reheat heat exchanger 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.

Residual Heat Removal Heat Exchangers. The LRA states that the fatigue analysis for the RHR heat exchangers explains that a fatigue analysis is not necessary for the associated transients

since they are very weak. The LRA also states that, when these transients were put through the criteria of ASME Code Section III, Paragraph NB-3222.4(d), it was concluded that a detailed fatigue analysis is not required. The LRA further states that all of these transients except "pressurization" are monitored by the Fatigue Monitoring Program. The specification describes the "pressurization" event as pressurization to the design pressure, at the design temperature, which can coincide with plant cooldown and plant heatup.

The applicant dispositioned the TLAA for the fatigue design of the residual heat removal heat exchangers in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of metal fatigue on the intended functions will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

Excess Letdown Heat Exchanger. The LRA state that the fatigue analysis of the excess letdown heat exchanger calculated a component maximum CUF of 0.154. The LRA states that based on the design specification, the excess letdown heat exchanger is designed for 100 operating cycles, which facilitates unusual maintenance or repair operations which require isolation of the normal letdown path. The LRA also states that Callaway has initiated excess letdown approximately 49 times over the past 11 years and if this sample is extrapolated, then 270 excess letdown initiation transient events would be anticipated for 60 years, resulting in a CUF of 0.415. The LRA further states that while the number of cycles is greater than the specified value, it is below the maximum allowable of 650.

The applicant dispositioned the TLAA for the fatigue design of the excess letdown heat exchanger in accordance with 10 CFR 54.21(c)(1)(ii), that the analysis has been projected to the end of the period of extended operation.

4.3.8.2 Staff Evaluation

The staff reviewed LRA Section 4.3.8 and the TLAAs for the fatigue design of the Class 2 letdown heat exchanger, letdown reheat heat exchanger and excess letdown heat exchanger to confirm, 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 staff also confirmed, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of fatigue for the Class 2 RHR heat exchangers and regenerative heat exchanger will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

The staff reviewed the applicant's TLAAs for the fatigue design of the Class 2 letdown heat exchanger, letdown reheat heat exchanger and excess letdown heat exchanger 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. The staff also reviewed the applicant's TLAA for the fatigue design of the Class 2 RHR heat exchangers and regenerative heat exchanger 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 components.

Regenerative Heat Exchanger. LRA Section 4.3.8 states that the regenerative heat exchanger tubesheets, shell side nozzles, tube side nozzles, and cross shell juncture were evaluated as part of the fatigue analysis. Furthermore, the analysis determined that the most limiting fatigue usage factor was 0.50 at the outlet tubesheet. The applicant stated that the only transients that

contribute to the CUF for this component are 200 cycles of the “letdown flow shutoff with prompt return to service” transient and 100 cycles of the “charging flow shutoff with prompt return to service” transient.

The analysis of the regenerative heat exchanger also contains a fatigue waiver for the tube side inlet nozzle in which 200 cycles of the “letdown flow shutoff with prompt return to service” transient, 100 cycles each of the “charging flow shutoff with prompt return to service” and the “charging and letdown shutoff and return to service transients,” and 200 cycles each of the plant heatup and cooldown transients were used. The staff reviewed LRA Table 4.3-2, which provides a listing of transients that are monitored by the Fatigue Monitoring Program, and confirmed that the transients used for the CUF for the outlet tubesheet and those used for the fatigue waiver of the tube side inlet nozzle are included.

The staff determined that the program includes three monitoring methods (cycle counting, CBF monitoring, and SBF monitoring) that are capable of managing metal fatigue during the period of extended operation. The staff also determined that the use of these three monitoring methods progressively provides a more refined monitoring approach to manage metal fatigue to ensure that the applicable allowable design limits are not exceeded. The staff determined that these characteristics of the applicant’s Fatigue Monitoring Program are consistent with GALL Report AMP X.M1. Specifically, for the regenerative heat exchanger the applicant’s program ensures that the numbers of transients actually experienced during the period of extended operation remain below the assumed number in the fatigue analysis and waiver or corrective actions will be taken. The staff’s evaluation of the Fatigue Monitoring Program is documented in SER Section 3.0.3.2.22.

In addition, the analysis indicated that the shell side nozzles, the tube side outlet nozzle, and cross shell junction are areas that are not subject to fatigue. The staff finds it appropriate that the analysis for the regenerative heat exchanger was reviewed by the applicant to confirm that the shell side nozzles, the tube side outlet nozzle, and cross shell junction are not subject to fatigue.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging related to fatigue analysis of regenerative heat exchanger 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 is crediting its Fatigue Monitoring Program, which the staff determined in SER Section 3.0.3.2.22 is consistent with GALL Report AMP X.M1, to manage metal fatigue to ensure that the allowable design limits on fatigue usage are not exceeded during the period of extended operation; otherwise, the applicant will take corrective actions in accordance with its program.

Letdown Heat Exchanger. LRA Section 4.3.8 provides a list of eleven transients and its associated design cycles that may have been used in the fatigue analysis of Class 2 heat exchangers. Specific to the letdown heat exchanger fatigue analysis, the staff noted that Transients 1, 2, 4, 5, 6, 7, 8, 9, and 10 were used. The applicant stated that Transients 1, 2, 8, 9, and 10 are monitored by the Fatigue Monitoring Program. The staff noted that these five transients will be cycle counted, as part of the Fatigue Monitoring Program, and involves initiating corrective actions if the cycle count for any one transient approaches an action limit. The staff’s evaluation of cycle counting monitoring method and the Fatigue Monitoring Program is documented in SER Section 3.0.3.2.22. The applicant stated that Transients 5 and 7 each with design cycles of 24,000 are load-following events. Since the design numbers of cycles for these transients are for a plant designed for load-following operation and the applicant does not

operate as a load-following plant, the staff finds it reasonable that these transients are not monitored and that it is not credible for the occurrences of these transients to approach the design limit of 24,000 during the period of extended operation. The staff's evaluation of Transients 4 and 6 is discussed below.

LRA Section 4.3.8 states that the fatigue analysis for the letdown heat exchanger indicated a maximum CUF of 1.84 for the flange, which is driven mainly by the load-following transient, Transient 4, "charging flow step decreased and return to normal." The applicant stated that since it does not practice load-following operation, the number of cycles expected to be experienced is a small fraction of the number of assumed. The LRA provides an evaluation in which the assumed number of this transient was dropped by an order of magnitude and the CUF dropped to 0.894.

The staff noted that the "charging flow step decreased and return to normal" transient with a design limit of 24,000 cycles was based on load-following operation. Thus, it may be reasonable to conclude that because the applicant's site does not practice load-following operation, there will be a margin between the design limit and the expected number of cycles for this transient through the period of extended operation. However, since the applicant reduced the number of cycles for this transient from 24,000 by an order of magnitude (i.e., 2,400), it is not clear to the staff if there is still a margin between the design number and expected number of cycles through the period of extended operation (i.e., approximately (3 cycles per month) x (12 months per year) x (60 years of operation) = 2,160 cycles). Therefore, the staff requires additional information to confirm the adequacy of the applicant's disposition in accordance with 10 CFR 54.21(c)(1)(ii), that the CUF of 0.894 for the letdown heat exchanger flange has been projected to be valid through the period of extended operation.

By letter dated September 6, 2012, the staff issued RAI 4.3-14 requesting the applicant provide the reason that there is sufficient margin to conclude that the TLAA has been projected to remain valid through the period of extended operation (i.e., 10 CFR 54.21(c)(1)(ii)), given that the CUF value of 0.894 may no longer be valid if the 3-occurrence-per-month assumption through the period of extended operation is exceeded.

In its response dated October 11, 2012, the applicant clarified that following an increase in reactor power, temperature increases and the reactor coolant expands causing the pressurizer level to rise. The applicant stated that to compensate for this, the charging flow rate decreases while the letdown flow remains constant. The applicant also stated that, originally, the plant load was assumed to change twice per day (one increase and one decrease), with an 80 percent capacity factor, which equates to 24,000 "charging flow step decrease and return to normal" transients. The staff noted that this original design is meant for a load-following plant. However, since the applicant operates its plant as base-loaded, it stated that the plant will normally experience power changes only at the beginning and at the end of a cycle. Based on these assumptions, the staff noted that since the applicant operates on an 18-month refueling cycle, there would be an estimated 80 load changes over a 60-year life. The staff noted that there is margin between this estimated 80 load changes and the 2,400 occurrences used in the revised analysis to accommodate any unforeseen operating issues that would necessitate a power reduction or increase.

The staff finds it reasonable that the "charging flow step decrease and return to normal" transient is not monitored because there is significant margin between the estimated number of transient occurrences through 60 years based on the applicant's base-loaded operating

practices and the 2,400 cycles used in the analysis to account for operating issues that would require or have required a power reduction or increase.

The staff finds the applicant's response acceptable because the applicant provided sufficient justification, as described above, that the number of "charging flow step decrease and return to normal" cycles assumed in the revised fatigue analysis of the letdown heat exchanger will not be exceeded during the period of extended operation and there is margin to account for unanticipated occurrences. The staff's concern described in RAI 4.3-14 is resolved.

LRA Section 4.3.8 states that the fatigue analyses of the letdown heat exchanger also include the tubesheet, tube side nozzles, and the studs, with CUF values of 0.910, 0.843, and 0.635, respectively. It also discusses that Transient 6, "letdown flow step decrease and return to normal," with a design limit of 2,000 cycles, is not a normal operating event with the plant at power, but was included in the analysis for conservatism. Furthermore, it states that this transient was assumed to occur approximately once a week for 40 years, and if this assumption is extended through the period of extended operation, then 3,000 events will be assumed to occur and the CUF will increase to 0.995, 0.880, and 0.696, respectively.

Additional information regarding the CUF contribution for each of the transients in the original fatigue analysis for this component is required for the staff to verify the adequacy of the TLAA disposition. ASME Code Section III, Paragraph NB-3222.4(e)(5), Step 1 indicates that transients shall be paired to produce a total stress difference range greater than the stress difference range of the individual cycles. It is not clear to the staff if the applicant has performed a CUF re-calculation consistent with the ASME Code to arrive at the conclusion that, through the period of extended operation, with 3,000 cycles of this transient assumed to occur, the CUF values will increase to 0.995, 0.880, and 0.696. Furthermore, the technical basis to support the assumptions that this transient occurs approximately once a week for 40 years and can be extended to 3,000 cycles for 60 years is not clear to the staff. In addition, it is not clear to the staff if these assumptions are conservative.

By letter dated September 6, 2012, the staff issued RAI 4.3-15, Part (a), requesting the applicant provide the CUF contribution, as documented in the original fatigue evaluation, for each of the transient pairing (including number of cycles used in each pairing) consistent with the provisions in ASME Code Section III, Paragraph NB-3222.4(e)(5). The staff also requested, in Part (b), that the applicant confirm that the CUF value has been recalculated consistent with ASME Code Section III Paragraph NB-3222.4(e)(5), to reach its assumption that the "letdown flow step decrease and return to normal" transient can be extended to 3,000 cycles for 60 years. In Part (c), the staff requested that the applicant justify the assumptions that the "letdown flow step decrease and return to normal" transient occurs approximately once a week for 40 years and can be extended to 3,000 cycles for 60 years.

In its response to RAI 4.3-15, Part (a), dated October 11, 2012, the applicant provided the CUF contributions from the tube side nozzle, tubesheet and stud stress report as documented in the original fatigue evaluation for the letdown heat exchanger, for each of the transient pairings (including number of cycles used in each pairing). The applicant also confirmed that the letdown heat exchanger CUF will be less than 1.0 if the number of "letdown flow step decrease and return to normal" transient events is increased to 3,000 cycles, consistent with ASME Code Section III, Paragraph NB-3222.4(e)(5). The staff noted that ASME Code Section III, Paragraph NB-3222.4(e)(5) provides the required procedures to analyze cyclic loading.

In its response to RAI 4.3-15, Part (b), the applicant stated that the letdown heat exchanger tubesheet CUF contribution by the "letdown flow decrease and return to normal" transient would

increase from 0.169 (0.144 + 0.018 + 0.007) to 0.2535 (1.5 x (0.144 + 0.018 + 0.007)). In addition, the applicant stated that this will increase the CUF from 0.910 to 0.995 and the response also provided the CUF contribution for each transient pair.

Based on staff's review of Table 4, "Tubesheet Fatigue Table for the Letdown Heat Exchanger" in the applicant's response, the CUF contribution from the third transient pair "#6 letdown flow decrease and return to normal [254 °C to 143 °C] (490 °F to 290 °F)" and "#6 letdown flow decrease and return to normal [60 °C to 193 °C] (140 °F to 380 °F)" would increase to 0.224 [(0.144/1,800) x 2,800]. Thus, the CUF contribution by the "letdown flow decrease and return to normal" transient would increase from 0.169 to 0.2615 (0.224 + 1.5 x (0.018 + 0.007)), as opposed to the applicant's conclusion of 0.2535.

The staff noted that this will increase the CUF from 0.910 to over 1.00. The staff noted that the CUF value must not exceed 1.0, which is the ASME Code Section III CUF requirement. The staff noted that the applicant must demonstrate that the recalculated CUF value will not exceed 1.0 through the period of extended operation to support the TLAA disposition in accordance with 10 CFR 54.21(c)(1)(ii).

By letter dated November 21, 2012, the staff issued RAI 4.3-15a requesting that the applicant justify that the recalculated CUF value does not exceed 1.0 assuming 3,000 cycles of "letdown flow decrease and return to normal" transient will occur through the period of extended operation.

In its response to RAI 4.3-15a dated December 13, 2012, the applicant provided an updated Table 5, "Tubesheet Fatigue Table for the Letdown Heat Exchanger." The applicant identified and corrected another error in the original design report, which affected the 7th transient pairing ("letdown flow increase and return to normal" at "[207 °C to 137 °C] (405 °F to 279 °F)" and "[143 °C to 207 °C] (290 °F to 405 °F)"), and resulted in an updated CUF of 0.903.

The applicant continued to explain that the 7th transient pairing erroneously includes 24000 events of "letdown flow increase and return to normal" at "(405°F to 279°F)" & "(290°F to 405°F)." The staff noted that when the number of "letdown flow decrease and return to normal" events is increased to 3000, as described in LRA Section 4.3.8, the number of paired events would decrease to 21000 events for the 7th transient.

The staff noted that, based on the corrected transient pairing and the corrected error identified by the staff in RAI 4.3-15a, the updated CUF for 60 years does not exceed the Code design limit of 1.0. The staff reviewed the information in the applicant's response, including the updated Table 5, "Tubesheet Fatigue Table for the Letdown Heat Exchanger," and determined that the calculation was performed consistent with ASME Code Section III NB-3222.4(e)(5).

In its response to RAI 4.3-15, Part (c), dated October 11, 2012, the applicant also stated that the "letdown flow step decrease and return to normal" transient is assumed to occur 2,000 times during the 40-year plant design life and if the number of events were extended through the period of extended operation, then 3,000 events will be assumed to occur. The applicant also explained that the letdown flow rate can be changed manually by switching from one letdown orifice to another or by valving in an additional orifice. The applicant stated that letdown flow is normally only changed to initiate maximum purification or to make boron concentration changes associated with load follow and plant shutdown, and both of these operations would normally involve an increase in letdown flow. Finally, the applicant stated that letdown flow reductions "do not support the typical operation" of the plant, and there are currently no plans to implement a letdown flow reduction below nominal letdown flow (75 gpm). The staff reviewed FSAR

Section 9.3.4.2.3.2 SP and noted that the letdown flow would be 120 gpm during normal operation with maximum purification.

The staff noted that since the applicant currently operates its plant on 18-month refueling cycles, it can be expected that approximately 40 cycles would occur in a 60-year timeframe because of plant shutdowns. The staff finds it reasonable that the applicant's assumed margin (approximately 2,960 cycles) accounts for the expected occurrences of the "letdown flow step decrease and return to normal" transient through the period of extended operation.

The staff finds the applicant's responses to RAIs 4.3-15 and 4.3-15a acceptable because the CUFs for the letdown heat exchanger (tubesheet, tube-side nozzle and stud) were recalculated and shown to be less than the design limit of 1.0 consistent with ASME Code Section III NB 3222.4(e)(5) and the applicant sufficiently justified, as described below, its assumption to increase the number of cycles for Transient 6 to 3,000. The staff's concerns described in RAIs 4.3-15 and 4.3-15a are resolved.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the analysis for the letdown heat exchanger has 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 number of operating cycles anticipated for 60 years of operation for the letdown heat exchanger will not be exceeded through the period of extended operation with sufficient margin to account for unanticipated operating cycles and the recalculated CUF values are less than the design limit of 1.0.

Letdown Reheat Heat Exchanger. LRA Section 4.3.8 provides a list of eleven transients and its associated design cycles that may have been used in the fatigue analysis of Class 2 heat exchangers. Specifically, Transients 1, 2, 4, 5, 6, 7 and 11 were used in the letdown reheat heat exchanger fatigue analysis. The applicant stated that Transients 1 and 2 are monitored by the Fatigue Monitoring Program. The staff noted that these two transients will be cycle counted, as part of the Fatigue Monitoring Program, and involves initiating corrective actions if the cycle count for any one transient approaches an action limit. The staff's evaluation of cycle counting monitoring method and the Fatigue Monitoring Program is documented in SER Section 3.0.3.2.22. The applicant stated that Transients 4 and 5 each with design cycles of 24,000 are load-following events. Since the design numbers of cycles for these transients are for a plant designed for load-following operation and the applicant does not operate as a load-following plant, the staff finds it reasonable that these transients are not monitored and that it is not credible for the occurrences of these transients to approach the design limit of 24,000 during the period of extended operation. The staff's evaluation of Transients 6, 7, and 11 are discussed below.

LRA Section 4.3.8 states that the fatigue analysis for the letdown reheat heat exchanger indicated a maximum CUF of 4.431 for the studs, which is driven mainly by the load-following transients, "letdown flow step increase and return to normal" and "load follow boration." Furthermore, the LRA states that it does not practice load-following operation and the assumed number of these transients was dropped by an order of magnitude and the CUF dropped to about 0.503.

The staff noted that the Transient 7, "letdown flow step increase and return to normal," and Transient 11, "load follow boration," each with a design limit of 24,000 cycles, were based on load-following operation; thus, it may be reasonable to conclude that because the applicant's site does not practice load-following operation there will be margin between the design limit and the expected number of cycles for these transients. However, since the applicant reduced the

number of cycles for these transients from 24,000 by an order of magnitude (i.e., 2,400), it is not clear to the staff if there is still a margin between the design number and expected number of cycles through the period of extended operation. Thus, the staff requires additional information to verify the adequacy of the applicant's disposition in accordance with 10 CFR 54.21(c)(1)(ii), that the CUF of 0.503 for the letdown reheat heat exchanger studs has been projected to be valid through the period of extended operation.

By letter dated September 6, 2012, the staff issued RAI 4.3-16 requesting the applicant provide the basis that there is sufficient margin to conclude that the TLAA has been projected to remain valid through the period of extended operation (i.e., 10 CFR 54.21(c)(1)(ii)), given that the CUF value of 0.503 may no longer be valid if, for each transient ("letdown flow step increase and return to normal" and "load follow boration"), a three-occurrence-per-month assumption through the period of extended operation is exceeded.

In its response to RAI 4.3-16 dated October 11, 2012, the applicant stated that the letdown reheat heat exchanger is part of the boron thermal regeneration (BTR) system and is used to heat the BTR system process fluid flowing through the shell side. The applicant stated that the "letdown flow step increase and return to normal" and "load follow boration" transients are load-following transients and they are meant to compensate for changes in the RCS water volume and boron concentration that accompany load changes. The staff noted that the applicant's original plant design assumed that it would be a load-following plant. However, since the applicant operates its plant as base-loaded, it stated that, ideally, the plant will experience power changes only at the beginning and at the end of a cycle. Based on these assumptions, the staff noted that since the applicant operates on an 18-month refueling cycle there would be an estimated 80 load changes over a 60-year life. The staff noted that there is margin between this estimated 80 load changes and the 2,400 occurrences used in the revised analysis to accommodate any unforeseen operating issues that would necessitate a power reduction or increase.

The staff finds it reasonable that "letdown flow step increase and return to normal" and "load follow boration" transients are not monitored because there is significant margin between the estimated number of transients occurrences through 60 years, based on the applicant's base-loaded operating practices, and the 2,400 cycles used in the analysis to account for operating issues that would require or have required a power reduction or increase.

The staff finds the applicant's response acceptable because the applicant provided sufficient justification, as described above, that the number of "letdown flow step increase and return to normal" and "load follow boration" transient cycles assumed in the revised fatigue analysis of the letdown reheat exchanger will not be exceeded during the period of extended operation and there is a margin to account for unanticipated occurrences. The staff's concern described in RAI 4.3-16 is resolved.

LRA Section 4.3.8 states that the fatigue analyses of the letdown reheat heat exchanger also include the shell and tube side nozzles and tubesheet, with CUF values of 0.054 and 0.47, respectively. The LRA discusses the transients that were included in the fatigue analyses for these components, the transients that will be monitored by the Fatigue Monitoring Program and the transients that will not be monitored. Specifically, for the Transient 6, "letdown flow step decrease and return to normal," with a design limit of 2,000 cycles, if the number of events is extended through the period of extended operation, then 3,000 events will be assumed to occur and the CUFs will increase to 0.57 for the tubesheet and 0.0563 for the tube side nozzles.

Additional information regarding the CUF contribution for each of the transients in the original fatigue analysis for this component is required for the staff to verify the adequacy of the TLAA disposition. ASME Code Section III Paragraph NB-3222.4(e)(5) Step 1 indicates that transients shall be paired to produce a total stress difference range greater than the stress difference range of the individual cycles. It is not clear to the staff if the applicant has performed a CUF recalculation, consistent with the ASME Code, to arrive at the conclusion that, through the period of extended operation with 3,000 cycles of this transient assumed to occur, the CUF values will increase to 0.57 for the tubesheet and 0.0563 for the tube side nozzles. Furthermore, the technical basis to support the assumption that this transient can be extended to 3,000 cycles for 60 years is not clear to the staff. In addition, it is not clear to the staff if this assumption is conservative.

By letter dated September 6, 2012, the staff issued RAI 4.3-17 requesting, in Part (a), that the applicant provide the CUF contribution, as documented in the original fatigue evaluation, for each of the transient pairing (including number of cycles used in each pairing) consistent with the provisions in ASME Code Section III, Paragraph NB-3222.4(e)(5). The applicant was also requested, in Part (b), to confirm that the CUF value has been recalculated consistent with ASME Code Section III, Paragraph NB-3222.4(e)(5), and was requested in Part (c) to justify its assumption that the "letdown flow step decrease and return to normal" transient can be extended to 3,000 cycles for 60 years. The applicant was requested, in Part (d), to clarify the nozzles CUFs that are not affected by the increase for this transient.

In its response to RAI 4.3-17, Parts (a) and (b), dated October 11, 2012, the applicant provided the CUF contributions from the tube side nozzle and tubesheet stress report as documented in the original fatigue evaluation for the letdown reheat heat exchanger, for each of the transient pairing (including number of cycles used in each pairing) consistent with ASME Code Section III, Paragraph NB-3222.4(e)(5).

The applicant also confirmed that the letdown reheat heat exchanger CUF will be less than 1.0 if the number of "letdown flow step decrease and return to normal" transient events is increased to 3,000 cycles, consistent with ASME Code Section III, Paragraph NB-3222.4(e)(5). The staff noted that ASME Code Section III, Paragraph NB-3222.4(e)(5) provides the required procedures to analyze cyclic loading. The applicant stated that the LRA incorrectly states 0.57 as the increased CUF for the tubesheet and that the LRA was revised to identify the corrected CUF value of 0.50 for the tubesheet.

In its response to RAI 4.3-17, Part (c), the applicant also stated in its response that the "letdown flow step decrease and return to normal" transient is assumed to occur 2,000 times during the 40-year plant design life and if the number of events were extended through the period of extended operation, then 3,000 events will be assumed to occur. The applicant also explained that the letdown flow rate can be changed manually by switching from one letdown orifice to another or by valving in an additional orifice. However, it is only normally changed to initiate maximum purification or to affect boron concentration changes associated with load follow and plant shutdown and there are currently no plans to implement a letdown flow reduction below nominal letdown flow (75 gpm). The staff reviewed FSAR Section 9.3.4.2.3.2 SP and noted that the letdown flow would be 120 gpm during normal operation with maximum purification. The applicant stated that the letdown flow reduction does not support the typical operation of the plant, such as to commence maximum purification or load following operation.

The staff noted that since the applicant currently operates its plant on 18-month refueling cycles, it can be expected that approximately 40 cycles occur because of plant shutdowns. In addition,

since the applicant does not operate as a load-following plant or operate in such a manner to normally initiate maximum purification, the staff finds it reasonable that there is margin (approximately 2,960 cycles) to account for occurrences of the "letdown flow step decrease and return to normal" transient through the period of extended operation.

In response to RAI 4.3-17, Part (d), the applicant revised the letdown reheat heat exchanger portion of LRA Section 4.3.8 to delete the statement "[t]he nozzles CUFs are not affected by this increase." The staff noted this statement was referring to the original design fatigue analyses and the applicant confirmed that these analyses are not the "current" fatigue analysis used to support the LRA. The staff finds the revision of LRA Section 4.3.8 acceptable because the confusion as to whether the tube side nozzles CUFs were affected by the increase of the "letdown flow step decrease and return to normal" transient to 3,000 cycles has been eliminated.

The staff finds the applicant's response acceptable because the CUFs for the letdown reheat heat exchanger were recalculated and shown to be less than the design limit of 1.0 consistent with ASME Code Section III, Paragraph NB-3222.4(e)(5) and the applicant sufficiently justified, as described above, its assumption to increase the number of cycles for Transient 6 to 3,000. The staff's concern described in RAI 4.3-17 is resolved.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(ii), that the analysis for the letdown reheat heat exchanger has 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 number of operating cycles anticipated for 60 years of operation for the letdown reheat heat exchanger will not be exceeded through the period of extended operation with sufficient margin to account for unanticipated operating cycles and the recalculated CUF values are considerably less than the design limit of 1.0 (i.e., 0.50 for the tubesheet and 0.0563 for the tube side nozzles).

Residual Heat Removal Heat Exchangers. LRA Section 4.3.8 provides a list of transients that were in the design specification for RHR heat exchangers. It also states that the fatigue analysis for the RHR heat exchangers explained that a fatigue analysis is not necessary for these transients since they are very weak and when these transients were put through the criteria of ASME Code Section III, Paragraph NB-3222.4(d), it was concluded that a detailed fatigue analysis is not required. The LRA continues to explain that all of these transients except "pressurization" are monitored by the Fatigue Monitoring Program and that the design specification describes the "pressurization" event as pressurization to the design pressure, at the design temperature and "can" coincide with plant cooldown and plant heatup. Based on this statement, the staff needed to confirm if the "pressurization" transient can also coincide with transients other than plant cooldown and plant heatup.

By letter dated September 6, 2012, the staff issued RAI 4.3-18, Part (a), requesting that the applicant confirm that the "pressurization" transient can only coincide with plant cooldowns and plant heatups and cannot coincide with any other transient. The applicant was also requested, in Part (b), to clarify if the "pressurization" transient will definitively coincide with each and every occurrence of the identified transient(s).

In its response to RAI 4.3-18, Part (a), dated October 11, 2012, the applicant clarified that the RHR system can only be placed in service below a RCS temperature of 177 °C (350 °F) and a RCS pressure less than 450 psig and these pressure and temperature conditions require a plant cooldown or heatup. Therefore, the applicant determined that the plant cooldown and plant heatup will conservatively account for the "pressurization" transient of the RHR heat

exchangers. The staff reviewed the FSAR Section 1.2.9.2 and noted that the RHR systems is designed to remove heat from the reactor coolant at a controlled rate when the reactor coolant pressure is less than 450 psig and the temperature is from 177 °C (350 °F) to 60 °C (140 °F).

Based on the RHR system design, the staff finds it reasonable that the "pressurization" transient, as used in the RHR heat exchanger fatigue analysis, is considered to coincide with a plant cooldown cycle or a plant heat up cycle. In addition, since the total number of design cycles for plant cooldowns and plant heatups (400 total cycles) is equal to the number of design cycles for the "pressurization" transient (400 cycles); the staff finds its reasonable that monitoring of plant heatup and cooldown cycles with the Fatigue Monitoring Program will ensure the design limit on the "pressurization" transient will not be exceeded during the period of extended operation.

Based on the acceptability of the applicant's response to RAI 4.3-18, Part (a), as described above, Part (b) of the request is moot.

The staff finds the applicant's response acceptable because the applicant confirmed that the "pressurization" transient coincides with a plant heat up or plant cooldown and the Fatigue Monitoring Program, as described above, ensures that the design limit of the "pressurization" transient will not be exceeded during the period of extended operation. The staff's concern described in RAI 4.3-18 is resolved.

The staff determined that the Fatigue Monitoring Program includes three monitoring methods (cycle counting, CBF monitoring and SBF monitoring) that are capable of managing metal fatigue during the period of extended operation. The staff also determined that the use of these three monitoring methods progressively provides a more refined monitoring approach to manage metal fatigue to ensure that the applicable allowable design limits are not exceeded. The staff determined that these characteristics of the applicant's Fatigue Monitoring Program are consistent with GALL Report AMP X.M1. Specifically for the RHR heat exchangers, the applicant's 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 corrective actions will be taken. The staff's evaluation of the Fatigue Monitoring Program is documented in SER Section 3.0.3.2.22.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging related to fatigue waiver of RHR heat exchangers 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 is crediting its Fatigue Monitoring Program, which the staff determined in SER Section 3.0.3.2.22 is consistent with GALL Report AMP X.M1, to manage metal fatigue to ensure that the allowable design cycles established in the fatigue waiver are not exceeded during the period of extended operation; otherwise, the applicant will take corrective actions in accordance with its program.

Excess Letdown Heat Exchanger. LRA Section 4.3.8 states that excess letdown heat exchanger calculated a component maximum CUF of 0.154. In addition, based on the design specification this heat exchanger is designed for 100 operating cycles. The staff noted that these operating cycles are meant to facilitate unusual maintenance or repair operations which require isolation of the normal letdown path. The applicant stated that it has initiated excess letdown approximately 49 times over the past 11 years and if this sample is extrapolated, then 270 excess letdown initiation transient events would be anticipated for 60 years, which results in a CUF of 0.415.

By letter dated December 13, 2012, as part of its response to RAI 4.3-2a the applicant provided Table 1, "Accumulation Rates that Support the 60-Year Projections," which clarified that the excess letdown heat exchanger operation transient did not rely on a short-term and long-term weighting of transient occurrences for the 60-year projection. The applicant's Table 1 in RAI 4.3-2a response also clarified that a linear extrapolation was used that encompassed transient occurrence from initial plant start-up until 2011 to determine the 60-year projection. The staff's evaluation of RAI 4.3-2a is documented in SER Section 4.3.1.2.2. The staff finds the linear extrapolation of the excess letdown heat exchanger operation transient conservative because it takes into account early plant operation when transient occurrences were common, which was prior to the applicant incorporating operating practices to reduce transient occurrences at Callaway. The staff finds it reasonable that the applicant will continue to improve its ability to operate its plant based on operating experience and limit the number of operating cycles to facilitate unusual maintenance or repair operations that require isolation of the normal letdown path. In addition, the staff finds that there is sufficient margin between the applicant's anticipated number of operating cycles for 60 years of operation (270) compared to the allowable of number of operating cycles (650) that equate to the a CUF limit of 1.0 to account for unanticipated operating cycles that would require isolation of the normal letdown path.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(ii), that the analysis for the excess letdown heat exchanger has 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 number of operating cycles anticipated for 60 years of operation will be less than the design through the period of extended operation with sufficient margin to account for unanticipated operating cycles.

4.3.8.3 FSAR Supplement

LRA Section A3.2.7 provides the FSAR supplement summarizing the TLAA for Class 2 heat exchangers. The staff reviewed LRA Section A3.2.7 consistent with the review procedures in SRP-LR Section 4.3.3.2, which state that the reviewer verifies that the applicant has provided information to be included in the FSAR supplement that includes a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the FSAR supplement, as amended by letters dated October 11, 2012, and December 13, 2012, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2, and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA for Class 2 heat exchangers, as required by 10 CFR 54.21(d).

4.3.8.4 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 TLAAs for the letdown heat, letdown reheat, and excess letdown heat exchangers 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 effects of metal fatigue on the intended functions of the regenerative heat exchangers and RHR heat exchangers, will be adequately managed by the Fatigue Monitoring Program for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.4 Environmental Qualification (EQ) of Electric Equipment

4.4.1 Summary of Technical Information in the Application

LRA Section 4.4 describes the applicant's TLAA for the evaluation of EQ for the period of extended operation. The applicant stated that the EQ of Electric Equipment Program is consistent with the requirements of NUREG-0588, Revision 1, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," Category I and is also committed to RG 1.89, Revision 0, "Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants," dated November 1974. The LRA states that "[t]he EQ [of Electric Equipment] manages applicable component thermal, radiation, and cyclic aging effects through the aging evaluations for the current operating license using methods for qualification for aging and accident conditions established by 10 CFR 50.49(f)." In addition, the LRA states that "re-analysis of an aging evaluation to extend the qualification of components is performed on a routine basis as part of the EQ [of Electric Equipment]." The LRA further states that "important attributes of reanalysis include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met)."

The applicant dispositioned the TLAA for EQ of the electric equipment, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of thermal, radiation, and cyclical aging on the intended functions will be adequately managed by the EQ of Electrical Components Program for the period of extended operation.

4.4.2 Staff Evaluation

The staff reviewed the applicant's TLAA for EQ of the electric equipment and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with the review procedures in SRP-LR Section 4.4.3.1.3, which state that an applicant must demonstrate the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The EQ requirements established by 10 CFR Part 50, Appendix A, Criterion 4, and 10 CFR 50.49 specifically require each applicant to establish a program to qualify electrical equipment so that such equipment, in its end-of-life condition, will meet its performance specifications during and following design basis accidents. The 10 CFR 50.49 EQ of the Electric Equipment Program is a TLAA for purposes of license renewal. These components have a qualified life equal to or greater than the current operating term and are covered by a TLAA. The TLAA of EQ of electrical components includes all long-lived, passive, and active electrical and instrumentation and controls (I&C) components that are important to safety and are located in a harsh environment. The harsh environments of the plant are those areas subject to environmental effects by a loss-of-coolant accident (LOCA), a high-energy line break (HELB), or post-LOCA environment. EQ equipment comprises safety-related and nonsafety-related equipment, the failure of which could prevent satisfactory accomplishment of any safety-related function and necessary post-accident monitoring equipment.

As required by 10 CFR 54.21(c)(1), the applicant must provide a list of EQ electrical equipment TLAAs. The applicant shall demonstrate one of the following for each type of EQ equipment TLAAs: (1) that the analyses remain valid for the period of extended operation, (2) that the analyses have been projected to the end of the period of extended operation, or (3) that the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The staff reviewed LRA Sections 4.4 and B3.2, "Environmental Qualification (EQ) of Electrical Components," plant basis documents, and additional information provided to the staff. It also interviewed plant personnel to verify whether the applicant provided adequate information to meet the requirement of 10 CFR 54.21(c)(1). For electrical equipment, the applicant used 10 CFR 54.21(c)(1)(iii) in its TLAA evaluation to demonstrate that the aging effects of EQ equipment will be adequately managed during the period of extended operation. Per 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 reviewed the applicant's EQ of Electric Equipment Program to determine whether it will ensure 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.

The staff's evaluation of the components qualification focused on how the EQ of Electric Equipment Program manages the aging effects to meet the requirements, in accordance with 10 CFR 50.49. The staff conducted an audit of the information provided in LRA Sections 4.4 and B.3.2 and the program basis documents. LRA Section B3.2 discusses the component reanalysis attributes, including analytical models, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions. On the basis of its audit and evaluation of the AMP as documented in SER Section 3.0.3.1.19, the staff finds that the EQ of Electric Equipment Program, which the applicant claimed to be consistent with GALL Report AMP X.E1, is consistent with the GALL Report. Therefore, the staff concludes that the applicant's EQ of Electric Equipment TLAA is implemented per the requirements of 10 CFR 54.21(c)(1)(iii).

The staff noted that LRA Section 4.4, "Environmental Qualification (EQ) of Electric Equipment," includes a discussion of mechanical EQ and states that the qualification for some mechanical equipment extends beyond 40 years. The LRA also states that the EQ of Electric Equipment TLAA also manages the aging of mechanical components.

However, SRP-LR Section 4.4, "Environmental Qualification (EQ) of Electric Equipment," Subsection 4.4.1, "Areas of Review," states that some nuclear power plants have mechanical equipment that was qualified in accordance with the provisions of Criterion 4 of Appendix A to 10 CFR Part 50. If a plant has qualified mechanical equipment, it is typically documented in the plant's master EQ list. If this qualified mechanical equipment requires the performance of a TLAA, it should be performed in accordance with the provisions of SRP-LR Section 4.7, "Other Plant-Specific Time-Limited Aging Analysis." If a TLAA of qualified mechanical equipment is necessary, it usually involves the environmental effects on components such as seals, gaskets, lubricants, hydraulic fluid, or diaphragms.

The inclusion of mechanical components in EQ of Electric Equipment TLAA is inconsistent with the guidance provided in SRP-LR Section 4.4.1, "Areas of Review." In addition LRA Table 3.6-1, Item 3.6.1.001, does not identify mechanical equipment as a component type for the EQ of Electric Equipment TLAA. By letter dated August 23, 2012, the staff issued RAI 4.4-1 requesting the applicant to explain why EQ of mechanical components is included in LRA Section 4.4, "Environmental Qualification (EQ) of Electric Components," contrary to the guidance provided in SRP-LR 4.4.1 with regard to TLAAs for mechanical components and associated AMR items. The staff also requested the applicant to explain the discrepancy between LRA Sections B3.2, 4.4, A2.2, and A3.3 with regard to the inconsistency in the application of aging management of EQ of mechanical components. In addition, the staff

requested the applicant to explain why the component type (electrical equipment) in LRA Table 3.6-1, Item 3.6.1-1, is inconsistent with LRA Section 4.4 that includes electrical and mechanical components.

In response letter dated September 20, 2012, the applicant stated that it has revised the following LRA sections as shown in LRA Amendment 10, to address the following:

(1) The EQ of mechanical equipment discussion was removed from Section 4.4, "Environmental Qualification (EQ) of Electric Components," and a new Section 4.7.10, "Mechanical Environmental Qualification," was created.

(2) The environmental qualification of mechanical equipment discussion was removed from Appendix A3.3, "Environmental Qualification (EQ) of Electric Components," and a new Section A3.6.10, "Mechanical Environmental Qualification," was created.

(3) Appendix A2.2 and Appendix B3.2 for the Environmental Qualification of Electrical Components Program were updated to be consistent with the mechanical [EQ] disposition in Section 4.7.10.

(4) Table 3.6.2-1 was revised to include a line for mechanical environmental qualification components. Further evaluation 3.6.2.2.1 also was revised to identify mechanical [EQ] components.

(5) Section 2.5.1.15 was added for mechanical environmental qualification components, and conforming changes were incorporated in Section 2.5 and Section 2.1.2.3.2.

(6) Conforming changes were made to Table 4.1-1, List of TLAAs.

The staff finds the applicant response acceptable because the removal of mechanical EQ from LRA Section 4.4 and the creation of a new LRA Section 4.7.10 for mechanical EQ is consistent with the guidance provided in SRP-LR Section 4.4.1, which states that a TLAA for mechanical components should be performed under the provision of SRP-LR Section 4.7, "Other Plant-Specific Time-Limited Aging Analysis." The staff also finds the associated LRA changes consistent with the addition of a separate TLAA for mechanical EQ. The staff evaluation of LRA Section 4.7.10, "Mechanical Environmental Qualification," is provided in SER Section 4.7.10. The staff's concern described in RAI 4.4-1 is resolved.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of thermal, radiation, and cyclical aging on the intended functions of the electric equipment will be adequately managed for the period of extended operation.

Additionally, the changes meet the acceptance criteria in SRP-LR Section 4.4.2.1 because the applicant's EQ of Electrical Components Program is capable of programmatically managing the qualified life of components within the scope of the program for license renewal. The continued implementation of the EQ of Electrical Components Program provides assurance that the aging effects will be managed and that components within the scope of the EQ of Electric Equipment TLAA will continue to perform their intended functions for the period of extended operation.

4.4.3 FSAR Supplement

LRA Section A2.2 provides the FSAR supplement summarizing the EQ of Electric Equipment TLAA. The staff reviewed LRA Section A2.2, as revised in LRA Amendment 10, consistent with the review procedures in SRP-LR Section 4.4.3.2, which state that the reviewer verifies that the

applicant has provided information to be included in the FSAR supplement that includes a summary description of the evaluation of the EQ of electrical equipment TLAA.

Based on its review of the EQ of Electrical Components FSAR supplement, the staff finds that LRA Section A2.2, as revised in LRA Amendment 10, meets the acceptance criteria in SRP-LR Section 4.4.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the EQ of electric equipment TLAA for the period of extended operation, 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, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of thermal, radiation, and cyclical aging on the intended functions of the electric equipment will be adequately managed by the EQ of Electrical Components Program for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.5 Concrete Containment Tendon Prestress

4.5.1 Summary of Technical Information in the Application

LRA Section 4.5, as amended by the applicant's LRA Amendment 37 in its letter dated June 17, 2014, describes the applicant's TLAA for its post-tensioned concrete containment structure with a cylindrical wall, a hemispherical dome, and a flat foundation slab. The LRA states that the post-tensioned tendons compress the concrete and permit the structure to withstand design basis accident internal pressures. The LRA also states that the Callaway post-tensioning system consists of 86 vertical, inverted U-shaped tendons, 135 cylinder hoop tendons, and 30 dome hoop tendons (for a total of 165 horizontal hoop tendons). The LRA further states that the vertical tendons extend through the full height of the cylindrical walls, are draped over the dome, and are anchored at the bottom of the base slab. The cylinder hoop tendons are anchored at buttresses located 240 degrees apart. The 30 hemispherical dome hoop tendons start at the springline and continue up to an approximate 45-degree vertical angle from the springline. Collectively, the inverted U-shaped vertical tendons and the horizontal dome tendons prestress the hemispherical dome.

The LRA states that the tendons are made of approximately 170 high-steel wires 0.64 centimeters (0.25 in.) in diameter and have an ultimate strength of approximately 1,000 tons. The LRA also states that the applied prestressing load is transferred to the structure through steel bearing plates embedded in concrete and the tensioned steel tendons relax with time while the concrete structure, which the tendons hold in compression, both creeps and shrinks.

The LRA states that tendon surveillances are performed under the Inservice Inspection Program per ASME Code Section XI, Subsection IWL, to ensure the integrity of the containment pressure boundary under design basis accident loads. The LRA also states that the acceptance criteria compare the measured individual tendon forces against the predicted lower limit (PLL) force lines, and the surveillance includes separate regression analyses for the vertical and horizontal tendon groups. The LRA further states that the analyses are used to confirm whether average prestress forces are expected to remain above their minimum required values (MRVs) for the remainder of the licensed operating period.

The LRA states that PLL and the regression analyses predict the future performance of the post-tensioning system to the end of design life and are TLAAs. The LRA also states that the tendon surveillance results from 2010, the 25-year tendon surveillance, found no significant abnormal degradation and no lift-off values from this surveillance below the predicted force line. The discussion below reviews the three parameters used in the implementation of the tendon surveillance program: MRV, PLL force lines, and the regression analysis.

Minimum Required Value. The LRA states that the MRV is the average tendon prestress force used in the prestressed concrete containment design analysis. The design prestress must account for the loss of prestressing force after the initial tensioning, in accordance with RG 1.35.1, "Determining Prestressing Forces for Inspection of Prestressed Concrete Containments." The LRA also states that the MRV is the acceptance criterion for the average tendon prestressing force over the entire plant life; it does not vary with the plant life. The applicant concluded that the MRV is not a TLAA because is not in accordance with Criterion 3 of 10 CFR 54.3(a), which states that TLAA for the purposes of this part "involve time-limited assumptions defined by the current operating term; for example, 40 years."

Predicted Lower Limit. The LRA, as amended by LRA Amendment 37 dated June 17, 2014, states:

> [t]he Concrete Containment Tendon Prestress program (Section B3.3), which is part of the ASME Section XI, Subsection IWL Inservice Inspection program, manages loss of tendon prestress. Predicted force lines are incorporated in the Concrete Containment Tendon Prestress program to identify any abnormal degradation in tendon prestressing force,

The amended LRA also states that the predicted loss lines determine the PLL force lines, which form the acceptance criteria for measured forces in individual tendons, and the calculations of PLL lines are consistent with RG 1.35.1, "Determining Prestressing Forces for Inspection of Prestressed Concrete Containments." The amended LRA further states that "actual measured values for each tendon are compared to their respective PLL values, with acceptance criteria consistent with ASME Section XI, Subsection IWL requirements."

The applicant dispositioned the TLAA for the PLL lines in accordance with 10 CFR 54.21(c)(1)(iii) to demonstrate that the PLL lines, developed as acceptance criteria for the prestress force losses in individual tendons of the concrete containment prestressing system, will be adequately managed by the Concrete Containment Tendon Prestress Program for the period of extended operation.

Regression Analysis. The LRA states that the lift-off trend lines are necessary to demonstrate that the tendon prestressing force will remain above the MRV at least until the next scheduled surveillance. The LRA also states that the tendon surveillances are scheduled every 5 years. The trend lines are calculated by regression of individual tendon lift-off data and are, therefore, consistent with NRC Information Notice (IN) 99-10, Revision 1, "Degredation of Prestressing Tendon Systems in Prestressed Concrete Containments," dated October 7, 1999. The regression analysis trend lines indicate lift offs in excess of the MRV for at least 60 years. The IWL Inspection Report includes the results through the 2010, 25-year surveillance.

LRA Table 4.5-1, "Vertical Tendon Regression Analysis," and Table 4.5-2, "Horizontal Tendon (Cylinder and Dome) Regression Analysis," summarize the input data (i.e., selected tendons, age and time stressed, lift-off force) from the 1st-year surveillance performed in 1985 to the last (25th-year surveillance) performed in 2010.

LRA Figure 4.5-1, “Regression Analysis of Vertical Tendons,” and Figure 4.5-2, “Regression Analysis of Horizontal Tendons,” plot the table surveillance data and the resulting regression analyses, along with the MRV.

The LRA further states that the current analysis demonstrates that the average tendon prestresses in each of the vertical group and hoop tendon group will remain above their MRV through 60 years of operation; therefore, the analysis is valid for the period of extended operation.

The applicant dispositioned the TLAA for the regression analyses in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

4.5.2 Staff Evaluation

The staff reviewed FSAR-Standard Plant (SP) Section 1.2.5.1.1, “Containment Structure,” and confirmed that the containment structure is a prestressed, post-tensioned concrete structure with a cylindrical wall, a hemispherical dome, and a flat foundation slab. The wall and dome form a prestressed, post-tensioned system consisting of horizontal tendons in the wall and inverted U-shaped vertical tendons in the wall and dome. The staff also reviewed FSAR-SP Appendix 3.8A, “Computer Programs Used for Structural and Seismic Analyses,” Section 3.8A.1.2, “Bechtel CE 239 Hemispherical Dome Tendon Analysis (TENDON),” and confirmed that the dome hoop tendons extend from the springline into the dome region up to 45 degrees latitude.

The staff further reviewed FSAR-SP Section 3.8.1.1.2, “Post-Tensioning System,” and confirmed the applicant’s statements as presented in LRA Section 4.5. In addition, the staff reviewed the summary presented in FSAR-SP Appendix 3A, “Conformance to NRC Regulatory Guides – Regulatory Guide 1.35, Revision 3, dated April 1979,” which states that inservice inspection of ungrouted tendons in prestressed concrete containment structures for the post-tensioning system follows the guidance of Bechtel Topical Report BC-TOP-5-A, Revision 3, “Prestressed Concrete Nuclear Reactor Containment Structures,” February 1975 (BC-TOP-5-A), as modified by RG 1.35, Revision 3, “Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containments.” Details of the Tendon Surveillance Program are in FSAR-SP Section 16.6.1.2, “Containment Vessel Structural Integrity Limiting Condition of Operation” which is outlined in TS 5.5.6 and further described in LRA Section B3.3, “Concrete Containment Tendon Prestress [Program].”

The staff noted that the applicant’s tendon surveillance program, inspection frequencies, and acceptance criteria are in accordance with Section XI, Subsection IWL of the ASME Boiler and Pressure Vessel (B&PV) Code and applicable addenda, as required by 10 CFR 50.55a, except where an exemption or relief has been authorized by the staff. Both the FSAR-SP and the applicant’s Concrete Containment Tendon Prestress Program discuss the PLL force lines, the MRV, and the regression analyses. These quantities are further reviewed and discussed in the appropriate sections for each of the staff’s evaluations below.

Minimum Required Value. The staff reviewed the applicant’s claim that the MRV (average tendon prestress force used in the concrete containment design analysis) is not a TLAA. The staff also reviewed BC-TOP-5-A and noted that the report provides guidance for calculating average stresses for each tendon group (vertical and horizontal) before any losses and, subsequently, to anticipated losses, such as slip at the anchorage and elastic shortening when seating the tendons. RG 1.35.1 provides guidance in establishing the predicted forces. The average initial seating force at the anchorage, therefore, is the MRV that serves as the

acceptance criterion for the average tendon prestressing force over the entire plant life (i.e., it does not vary with the plant life).

The staff finds that the applicant has demonstrated that the MRV is not a TLAA because it does not satisfy 10 CFR 54.3(a), Criterion (3), which states that TLAAs must involve time-limited assumptions defined by the current operating term.

Predicted Lower Limit. The staff reviewed LRA Section 4.5 (as amended by LRA Amendment 37) regarding the Predicted Lower Limit TLAA and the corresponding disposition of 10 CFR 54.21(c)(iii), consistent with the review procedures in SRP-LR Section 4.5.3.1.3, which states that the reviewer verifies the applicant has identified the appropriate program in the GALL Report (i.e., AMP X.S1, "Concrete Containment Tendon Prestress") and has in place a program consistent with the corresponding generic program in the GALL Report.

The staff confirmed that the PLL calculated data for the TLAA, are developed from the loss of prestress model consistent with RG 1.35.1 and compared to measured lift-off force values as discussed in the applicant's Concrete Containment Tendon Prestress program in accordance with Section XI, Subsection IWL of the ASME Code, using edition and addenda as required by 10 CFR 50.55a. The staff evaluated and documented the applicant's proposed enhancement to the Concrete Containment Tendon Prestress program (see Commitment No 32) in SER Section 3.0.3.2.23.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the PLL lines, developed as acceptance criteria for the prestress force losses in individual tendons of the concrete containment prestressing system, will be adequately managed for the period of extended operation. Additionally, this meets the acceptance criteria in SRP-LR Section 4.5.2.1.3 because the applicant has in place an AMP consistent (after enhancements) with GALL Report AMP X.S1 to adequately manage the development of the PLL lines for tendon prestress loss during the period of extended operation.

Regression Analysis. The staff reviewed LRA Section 4.5 regarding the regression analysis-based trend lines and the corresponding disposition of 10 CFR 54.21(c)(i), consistent with the review procedures in SRP-LR Section 4.5.3.1.1, which state that the trend line of the measured prestressing force shows that the existing analysis will cover the period of extended operation. The staff also reviewed LRA Table 4.5-1, "Vertical Tendon Regression Analysis," and LRA Table 4.5-2, "Horizontal Tendon (Cylinder and Dome) Regression Analysis," and the corresponding figures, Figure 4.5-1, "Regression Analysis of Vertical Tendons," and Figure 4.5-2, "Regression Analysis of Horizontal Tendons," and noted that trend lines are calculated by regression of individual tendon lift-off data. The staff confirmed that the reported lift-off forces in the LRA are as those listed in the audited Document No. CA-N1042-500, "Final Report for the Callaway Nuclear Plant 25th Year Containment Building Tendon Surveillance."

The staff then examined the LRA aforementioned figures and noted that the applicant considered the information provided in IN 99-10, Revision 1, Attachment 3, "Comparison and Trending of Prestressing Forces," by using each sampled tendon's lift-off force as a data point instead of the group averages at the scheduled surveillance intervals. The staff noted that this approach provides the true representation of the variability of the tendon forces (lift-off forces) with respect to time sought by IN 99-10, Revision 1, Attachment 3. Based on the applicant's regression analysis, the lift-off forces will remain above the MRV for at least 60 years.

The staff finds the applicant has demonstrated in accordance with 10 CFR 54.21(c)(1)(i), that the regression analysis for the horizontal (hoop) and vertical tendon trend lines is valid for the period of extended operation.

4.5.3 FSAR Supplement

Minimum Required Value. The staff concludes that no FSAR supplement is required for the calculated MRV because the MRV is not time dependent but a constant quantity throughout the plant life and, hence, does not require a TLAA.

Predicted Lower Limit. LRA Section A3.4, as amended by LRA Amendment 37 dated June 17, 2014, provides the FSAR supplement summarizing the PLL force lines TLAA. The staff reviewed amended LRA Section A3.4 consistent with the review procedures in SRP-LR Section 4.5.3.2, which state that the reviewer verifies that the applicant has provided information to be included in the FSAR supplement that includes a summary description of the evaluation of the tendon prestress TLAA.

The staff also noted that the applicant plans to enhance the Concrete Containment Tendon Prestress program and this TLAA through a common commitment (see Commitment No. 32), as discussed in SER Section 3.0.3.2.23.

Based on its review of the FSAR supplement, as amended by LRA Amendment 37 dated June 17, 2014, the staff finds that it meets the acceptance criteria in SRP-LR Section 4.5.2.2, and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address PLL force lines, as required by 10 CFR 54.21(d).

Regression Analysis. LRA Section A3.4 Concrete Containment Tendon Prestress provides the FSAR supplement summarizing the regression analysis trend lines TLAA. The staff reviewed LRA Section A3.4 consistent with the review procedures in SRP-LR Section 4.5.3.2 which state that the reviewer verifies that the applicant has provided information to be included in the FSAR supplement that includes a summary description of the evaluation of tendon prestress TLAA.

Based on its review of the FSAR supplement, the staff finds that it meets the acceptance criteria in SRP-LR Section 4.5.2.2 and is, therefore, acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the tendon prestress regression analysis trend lines, 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 demonstrated that the MRV is not a TLAA because it does not satisfy 10 CFR 54.3(a)(3). The staff concludes that the applicant has provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(i), that the trend lines based on regression analysis for the horizontal and vertical tendon groups remain valid for the period of extended operation. The staff also concludes that the applicant has provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(iii), that the PLL force lines will be adequately managed by the Concrete Containment Tendon Prestress Program for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluations, as required by 10 CFR 54.21(d).

4.6 Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analyses

LRA Section 4.6 describes the applicant's TLAA of the containment structure liner plate, containment access hatches, and leak chase channels. The LRA states that the Callaway prestressed concrete containment vessel is designed to Bechtel Topical Report BC TOP-5-A, Revision 3. The LRA states that the containment is poured against a steel membrane liner designed to BC-TOP-1 Revision 1. The LRA states that the Callaway containment liner and other metal containment (MC) components (e.g., containment penetrations) were "designed to stress limit criteria of BC-TOP-1 Revision 1, independent of the number of load cycles, and require no fatigue analyses, with the exception of the main steam and feedwater penetrations, the containment access hatches, and the leak chases." The staff's evaluation of the applicant's claim that Callaway's metal containment liner requires no fatigue analysis is documented in SER Section 4.1.2.1.2. The staff's evaluation of the applicant's fatigue analyses for the main steam and feedwater penetrations, the containment access hatches, and the leak chases is documented is SER Section 4.6.1 and 4.6.2 below.

4.6.1 Design Cycles for the Main Steam Line and Feedwater Penetrations

4.6.1.1 Summary of Technical Information in the Application

LRA Section 4.6.1 states that BC-TOP-1 accounts for cyclical loads in the design of the main steam penetrations. The LRA states that "[t]hese cyclic loads include: 10 steady state operating thermal gradient plus steam pipe rupture cyclic loads (BC-TOP-1, Part II, "Loading Condition IV") and 100 lifetime steady state operating thermal gradient plus normal operating cyclic loads; i.e., Startup-Shutdown (BC-TOP-1, Part II, "Loading Condition V")."

The LRA states that the analyses in BC-TOP-1 do not qualify the components on a generic basis, but represent an acceptable method in which to demonstrate the components will meet the requirements of BC-TOP-5-A, Appendix C; however, the analyses must be performed, or at least confirmed to be conservative, on a plant-specific basis. The LRA also states that the specific analyses were performed for the main steam line penetrations and the feedwater penetrations at Callaway. The LRA further states that the analysis uses the simplified approach set in ASME Code Subparagraph NB-3228.3 of Section III, and it is only required if the penetration fails to meet the $3S_M$ requirement of Subparagraph NB-3222.2.

BC-TOP-1 Loading Condition IV – Normal Plus Pipe Rupture – 10 Cycles. For "loading condition IV" (normal plus pipe rupture), the LRA states that a main steam line or feedwater rupture is only anticipated to occur once during the design lifetime. However, the original calculation used 10 occurrences; therefore, the one anticipated occurrence is bounded by the design calculation, and the evaluation remains valid for the period of extended operation.

The applicant dispositioned the TLAA for loading condition IV of the main steam and feedwater lines, in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid for the period of extended operation.

BC-TOP-1 Loading Condition V – Normal Penetration Thermal Gradient Plus Startup-Shutdown – 100 Cycles. For "loading condition V," (normal thermal gradient plus operating cycle), the LRA states that stress intensity of the feedwater penetrations do not exceed the $3S_M$ requirement of NB-3222.2, therefore the cyclic loading aging effect does not need to be analyzed and the analysis is not a TLAA.

For “loading condition V,” the LRA states that the allowable stress is based on 100 startup-shutdown cycles for an assumed plant design life of 40 years, however, a review of the ASME Code Section III Table I-9-1 shows that the allowable stress for 500 cycles envelopes the calculated stress. The LRA also states that 500 cycles exceeds the number of cycles projected for 60 years; therefore, the calculation has been projected through the period of extended operation. The applicant dispositioned the analysis for the main steam line penetrations, in accordance with 10 CFR 54.21(c)(1)(ii), that the analysis has been projected to the end of the period of extended operation.

4.6.1.2 Staff Evaluation

BC-TOP-1 Loading Condition IV – Normal Plus Pipe Rupture – 10 Cycles. The staff reviewed the applicant’s TLAA associated with “loading condition IV” for the main steam line and feedwater containment penetrations to verify, in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid for the period of extended operation.

The staff reviewed the applicant’s TLAAs associated with “loading condition IV” for the main steam line and feedwater containment penetrations and the corresponding disposition consistent with the review procedures in SRP-LR Section 4.6.3.1.1.1. These procedures state that the reviewer should verify 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 and that 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 BC-TOP-1 Section 5.3.4, “Loading Condition IV,” and noted that the original calculation assumed 10 cycles for this loading condition. The staff confirmed that LRA Table 4.3-2, “Transient Accumulations and Projections,” replicates the information provided in FSAR-SP Table 3.9(N)-1, “Summary of Reactor Coolant System Analyzed Design Transients,” which states that the reactor trip from full power, with cooldown, with safety injection is expected to be, at most, a single event during the design plant lifetime. Therefore, the calculation based on 10 cycles remains valid for the period of extended operation.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the analysis for “loading condition IV” for the main steam line and feedwater containment penetrations remains valid for the period of extended operation. Additionally, the analysis meets the acceptance criteria in SRP-LR Section 4.6.2.1.1.1 because the number of assumed cyclic loads will not be exceeded during the period of extended operation.

BC-TOP-1 Loading Condition V – Normal Penetration Thermal Gradient Plus Startup-Shutdown – 100 Cycles. The staff reviewed the applicant’s TLAA associated with the analysis of “loading condition V” for the feedwater containment penetrations to verify that the analysis is not a TLAA. The staff audited the applicant’s TLAA basis document and noted that Callaway performed a plant-specific evaluation for the feedwater penetrations as an addendum to the BC-TOP-1 calculations. According to the calculations referenced in the basis document, the stress for the feedwater penetrations does not exceed the allowable primary and secondary stress intensity $3S_M$ requirement of NB-3222.2 for “loading condition V.” The analyses in the CLB for “loading condition V,” for the feedwater containment penetrations does not include any cyclic loading aging effects. Therefore, the staff concludes that the calculation for feedwater penetrations does not meet the definition of a TLAA, in accordance with 10 CFR 54.3(a)(2).

The staff reviewed the applicant's TLAA associated with the analysis of "loading condition V" for the main steam line containment penetration to verify, 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.

The staff reviewed this TLAA consistent with the review procedures in SRP-LR Section 4.6.3.1.1.2, which state that the reviewer should review operating transient experience and a list of the increased number of assumed cyclic loads projected to the end of the period of extended operation to ensure that the cyclic load projection is adequate.

The staff reviewed BC-TOP-1 and noted that loading condition V includes the normal thermal gradient plus an operating cycle, which is equivalent to a startup-shutdown cycle. The original allowable stress was based on 100 startup-shutdown cycles. The staff reviewed LRA Table 4.3-2, "Transient Accumulations and Projections," and noted that 65 startups and shutdowns are expected for 60 years. The projected value of 65 cycles is below the 100 cycles associated with an allowable stress greater than the actual calculated stress; therefore, the calculation has been projected to the end of the period of extended operation.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(ii), that the analysis for "loading condition V" for the main steam line containment penetration has been projected to the end of the period of extended operation. Additionally, the analysis meets the acceptance criteria in SRP-LR Section 4.6.2.1.1.2 because calculations were re-evaluated based on an increased number of assumed cyclic loads to cover the period of extended operation.

4.6.1.3 FSAR Supplement

LRA Section A3.5.1 provides the FSAR supplement summarizing the main steam line and feedwater penetrations TLAAs. The staff reviewed LRA Section A3.5.1 consistent with the review procedures in SRP-LR Section 4.6.3.2.

Based on its review of the FSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.6.2.2, and is, therefore, acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address main steam line and feedwater penetrations TLAAs, as required by 10 CFR 54.21(d).

4.6.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(i), that the analysis for "loading condition IV" for the main steam line and the feedwater penetrations remains valid for the period of extended operation. The staff also concludes that the applicant has provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(ii), that the analysis for "loading condition V" for the main steam line has been projected to the end of the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.6.2 Fatigue Waiver Evaluations for the Access Hatches and Leak Chase Channels

4.6.2.1 Summary of Technical Information in the Application

LRA Section 4.6.2 describes the applicant's TLAA for the fatigue waivers associated with the containment access hatches and the leak chase channels.

Access Hatches. The LRA states that a fatigue waiver evaluation for the access hatches was completed in accordance with ASME Code Section III, Subsection NE-3222.4(d).

The LRA states that two of the six criteria in the access hatch evaluation include time-dependent assumptions, as follows:

- the evaluation assumes 1,920 pressure fluctuations from atmospheric to design pressure and back to atmospheric pressure during normal operation to satisfy fatigue waiver criterion 1
- the evaluation assumes 160 temperature fluctuations between 10 °C (50 °F) and 49 °C (120 °F) during startup and shutdown to satisfy fatigue waiver criterion 3

The LRA also states that containment pressure will only fluctuate between atmospheric and design pressure during integrated leak rate tests (ILRT) conducted every 10 years and will only experience the temperature fluctuations during startups and shutdowns. The LRA states that the number of cycles assumed will not be exceeded during the period of extended operation; therefore, the applicant dispositioned the TLAA for the access hatch, in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid for the period of extended operation.

Leak Chase Channels. The LRA states that a fatigue waiver evaluation was completed in accordance with ASME Code Section III, Subsection NE-3222.4(d).

Two of the six criteria of the ASME Code Section III, Subsection NE-3222.4(d), in the leak chase evaluation include time-dependent assumptions, as follows:

- the evaluation assumes 40 Type A ILRT design pressure tests to satisfy fatigue waiver criteria 1 and 2
- the evaluation assumes 1,265 thermal transients, which considers all design basis transients over 40 years, as identified in FSAR-SP Table 3.9(N)-1A, to satisfy fatigue waiver criterion 3

The LRA further states that the Type A ILRT is only conducted every 10 years, and the only thermal transients that affect the containment components are heatup and cooldowns, which have a design number of 200 cycles. The projected values will not exceed the assumed values during the period of extended operation; therefore, the applicant dispositioned the TLAA for the leak chases, in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid for the period of extended operation.

4.6.2.2 Staff Evaluation

Access Hatches. The staff reviewed the applicant's TLAA for the containment access hatch fatigue waiver and the corresponding disposition of 10 CFR 54.21(c)(1)(i) consistent with the review procedures in SRP-LR 4.6.3.1.1.1. These procedures state that the number of assumed transients used in the existing calculations for the current operating term and the extrapolation

to 60 years of operation of the number of operating transients experienced to date are reviewed to confirm that the number of transients in the existing analyses will not be exceeded during the period of extended operation.

The staff noted that, for Criterion 1 of ASME Code Section III, Subsection NE-3222.4(d), the applicant's evaluation assumes 1,920 pressure fluctuations from atmospheric to design pressure and back to atmospheric. This cycle would only occur during accident conditions or during ILRTs, which are conducted, on average, every 10 years. This results in much fewer cycles over 60 years than assumed in the original fatigue waiver calculation. The staff further noted that, to satisfy fatigue waiver criterion 3, the applicant's evaluation assumes 160 temperature fluctuations between 10 °C (50 ° F) and 49 °C (120 °F). There are several other transients that may lead to a significant temperature fluctuation in the containment (e.g., reactor trip, RCS depressurization, loss of power). As described in SER Section 4.3.1.2.2 on the applicant's response to RAI 4.3-5 by letter dated October 11, 2012, the applicant explained that if any of these transients lead to a cooldown, the cooldown would be counted independently, as would the subsequent heatup. The staff found the applicant's response acceptable and its evaluation of this concern associated with RAI 4.3-5 is provided in SER Section 4.3.1.2.2. Therefore, the cooldown-heatup transient is an acceptable measure of the temperature cycles in containment. The staff reviewed LRA Table 4.3-2, "Transient Accumulations and Projections," and noted that 65 startups (heatups) and shutdowns (cooldowns) are expected for 60 years. The projected value of 65 cycles is well below the 160 cycles assumed in the original calculation. Since the values assumed in the original fatigue waiver analysis bound the expected values for the period of extended operation, the analysis remains valid for the period of extended operation.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the analysis for the containment access hatch fatigue waiver remains valid for the period of extended operation. Additionally, the analysis meets the acceptance criteria in SRP 4.6.2.1.1.1 because the containment access hatch fatigue waiver number of assumed cyclic loads will not be exceeded during the period of extended operation.

Leak Chase Channels. The staff reviewed the applicant's TLAA for the for the leak chase channel fatigue waiver and the corresponding disposition of 10 CFR 54.21(c)(1)(i), consistent with the review procedures in SRP-LR 4.6.3.1.1.1. These procedures state that the number of assumed transients used in the existing calculations for the current operating term and the extrapolation to 60 years of operation of the number of operating transients experienced to date are reviewed to confirm that the number of transients in the existing analyses will not be exceeded during the period of extended operation.

The staff noted that for fatigue waiver criteria 1 and 2, the applicant's evaluation assumes 40 pressure fluctuations associated with Type A ILRTs (i.e., pressure fluctuations from atmospheric to design). As noted above, this testing only occurs, on average, every 10 years, which results in fewer cycles over 60 years than the 40 assumed in the original fatigue waiver calculation. The staff also noted that for fatigue waiver criterion 3, the applicant's evaluation assumes 1,265 thermal transients. As stated above, the only transients that will cause a significant thermal transient on containment components are the heatups and cooldowns, which, as noted in LRA Table 4.3-2, are projected to be 65 occurrences over 60 years. Since the values assumed in the original fatigue waiver analysis bound the expected values for the period of extended operation, the analysis remains valid for the period of extended operation.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the analysis for the leak chase channel fatigue waiver remains valid for the period of extended operation. Additionally, the analysis meets the acceptance criteria in SRP 4.6.2.1.1.1 because the leak chase channel fatigue waiver number of assumed cyclic loads will not be exceeded during the period of extended operation.

4.6.2.3 FSAR Supplement

LRA Section A3.5.2 provides the FSAR supplement summarizing the access hatches and leak chase channels fatigue waiver TLAAs. The staff reviewed LRA Section A3.5.2 consistent with the review procedures in SRP-LR Section 4.6.3.2, which states that the reviewer verifies that the applicant has provided information to be included in the FSAR supplement that includes a summary description of the evaluation of the penetrations fatigue TLAA.

Based on its review of the FSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.6.2.2 and is, therefore, acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the access hatches and leak chase channels fatigue waiver TLAAs, 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, in accordance with 10 CFR 54.21(c)(1)(i), that the analyses for the containment access hatches and the containment leak chase channels fatigue waiver TLAAs remain valid for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7 Other Plant-Specific Time-Limited Aging Analyses

4.7.1 Containment Polar Crane, Fuel Building Cask Handling Crane, Spent Fuel Pool Bridge Crane, and Refueling Machine CMAA 70 Load Cycle Limits

4.7.1.1 Summary of Technical Information in the Application

LRA Section 4.7.1 describes the applicant's TLAA for the containment polar crane, fuel building cask handling crane, spent fuel pool bridge crane, and refueling machine Crane Manufacturers Association of America (CMAA) 70 load cycle limits. The LRA states that the CMAA 70 crane service classification for each machine depends, in part, on the assumption that the number of stress cycles at or near the maximum allowable stress will not exceed the number assumed for that design class. The LRA further states that in operation, this means the number of lifts that approach or equal the design load (significant lifts) will not exceed the number of stress cycles assumed for that design class. Therefore, the applicant concluded that the design of cranes for these standard numbers of lifts for the plant lifetime is a TLAA.

Design Lifts of Heavy-Lift Cranes. The LRA states that the cask handling crane is a CMAA 70, Class A crane designed for 100,000 full-capacity lifts in a design lifetime. The LRA also states that, to date, this crane has raised no significant number of heavy lifts, not yet shipped spent fuel, nor moved any spent fuel to onsite storage outside the spent fuel pool. The applicant assumed fuel used during the 80 postulated refueling operations is transferred to dry storage before the end of the period of extended operation, moving approximately 200 casks (80 refuelings times 90 assemblies per refueling, plus 193 initial core load, divided by 37 assemblies

per cask), resulting in about 400 lifts over its service life, which will not exceed the 100,000 cycles specified for CMAA 70, Class A service.

The LRA states that the polar crane is a CMAA 70, Class C crane designed for 500,000 full-capacity lifts in a design lifetime. The LRA states that the polar crane trolley is rated at 260 tons; a second temporary trolley, rated at 220 tons, was installed to permit heavier lifts during construction; and the bridge is rated for 440 tons. The LRA states that the number of polar crane dual trolley capacity construction lifts is estimated to be 14, with about 70 additional lifts at the single trolley capacity, including replacement steam generator lifts. The LRA also states that the polar crane specification anticipated 16 rated lifts per year, which would be 960 rated lifts for a 60-year design life. The polar crane, however, is used only for removal and reinstallation of the vessel head, upper internals, and lower internals, which will result in 480 lifts over a 60-year life. The LRA further states that, even if the specified number is used, the polar crane will only experience 1,044 lifts over its service life (14 dual trolley construction lifts plus 70 single trolley construction lifts plus 960 specified lifts) and, therefore, given the frequency of polar crane operation, it will not exceed the 500,000 cycles specified for CMAA 70, Class C Service.

Design Lifts of the Spent Fuel Pool Bridge and Refueling Machine. The LRA states that the spent fuel pool bridge crane is CMAA 70, Class B, and therefore, rated for up to 100,000 lifetime lifts. The LRA states that the spent fuel bridge crane is used to lift the fuel storage pool transfer gates to and from the storage racks and to move new and spent fuel assemblies. The LRA also states that the spent fuel pool bridge crane is conservatively expected to perform about 736 lifts per fuel cycle, consisting of:

- offload – 193 lifts per fuel cycle
- reload – 193 lifts per fuel cycle
- new fuel receipt – 90 lifts per fuel cycle
- cleaning – 100 lifts per fuel cycle
- fuel reshuffle – 160 lifts per fuel cycle

However, once Callaway commences dry cask storage, additional lifts will be necessary. The LRA states that the number of lifts is estimated to be the total number of new fuel assemblies received over 80 assumed refueling, plus 193 lifts for initial core loading. The LRA also states that moving the fuel storage gate adds about 160 lifetime lifts for the spent fuel bridge crane (2 lifts per refueling). Therefore, the total expected lifetime lifts for the spent fuel pool bridge crane is (736 times 80 refuelings) plus (90 times 80 plus 193) plus 160, which equals 66,433 lifts.

The LRA states that the refueling machine, used to load, unload, and move fuel assemblies within the reactor core and to transfer fuel to and from the fuel transfer tube only requires about two refueling machine lifts per fuel assembly. There LRA states that there are 193 assemblies in a full core, or roughly 400 lifts for the refueling machine in a normal refueling outage and Callaway is designed for 80 refuels, for about 32,000 fuel handling lifts.

The LRA also stated the spent fuel pool bridge and refueling machines will experience only a fraction of their rated lifetime number of lifts; therefore, the spent fuel bridge and refueling machines will not exceed the 100,000 cycles specified.

The applicant dispositioned the TLAAs for the containment polar crane, fuel building cask handling crane, spent fuel pool bridge crane, and refueling machine CMAA 70 load cycle limits,

in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

4.7.1.2 Staff Evaluation

The staff reviewed LRA Section 4.7.1 and the TLAAs for the containment polar crane, fuel building cask handling crane, spent fuel pool bridge crane, and refueling machine to verify, in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation. The staff reviewed these TLAAs consistent with the review procedures in SRP-LR Section 4.7.3.1.1, which state that the existing analyses should be shown to be bounding, even during the period of extended operation.

The staff also reviewed the LRA referenced FSAR-SP Section 9.1.4, "Fuel Handling System," and noted that it is composed of cranes, equipment, special fuel handling devices, and a fuel transfer system that are designed to meet the seismic and safety requirements of the plant. The staff noted that the section discusses the classification and function of (1) the cask handling crane (CMAA 70, Class A), (2) the spent fuel bridge crane (CMAA 70, Class B), (3) the containment building polar crane (CMAA 70, Class C), and (4) the refueling machine, which are further reviewed below.

Design Lifts of Heavy-Lift Cranes. The staff reviewed LRA Section 4.7.1 and Section 9.1.4, "Fuel Handling System," of the Callaway FSAR-SP and confirmed that the fuel building cask handling crane is used to handle spent fuel shipping casks between trucks, the loading pool, and the washdown pit. LRA Table 4.7-1 shows that the estimated number of lifts for 60 years of operation will not exceed the maximum number of lifts for which the fuel building cask handling crane was designed. Considering the applicant's assumption that all fuel used during the 80 postulated refueling operation is transferred to dry storage before the end of the period of extended operation, the estimated maximum number of significant crane lifts for the fuel building cask handling crane is 400 lifts. The staff finds that this estimated number of lift cycles is significantly less than the 100,000 permissible cycles for a CMAA 70 Class A crane and, therefore, is acceptable.

The staff reviewed LRA Section 4.7.1 and FSAR-SP Section 9.1.4, "Fuel Handling System," and confirmed that the containment building polar crane is used, in conjunction with various lifting rigs, to remove the reactor vessel head, the reactor vessel upper internals, and the lower internals, and for routine maintenance and inservice inspection. LRA Table 4.7-1 shows that the estimated number of lifts for 60 years of operation will not exceed the maximum number of lifts for which the polar crane was designed. The estimated number of dual trolley capacity construction lifts is estimated to be 14, with about 70 additional lifts at the single trolley capacity, for a total of 84 lifts. The crane specification anticipated 16 rated lifts per year, which for a 60-year design life, would be 960 lifts. The estimated maximum number of significant crane lifts for the containment building polar crane is 1,044 lifts. The staff finds that this estimated number of lift cycles is significantly less than the 500,000 permissible cycles for a CMAA 70 Class C crane and, therefore, is acceptable.

Design Lifts of the Spent Fuel Pool Bridge and Refueling Machine. The staff reviewed LRA Section 4.7.1 and FSAR-SP Section 9.1.4, "Fuel Handling System," and confirmed that the spent fuel pool bridge crane is used to transport new and spent fuel to and from various locations inside the fuel building. LRA Table 4.7-1 shows that the estimated number of lifts for 60 years of operation will not exceed the maximum number of lifts for which the spent fuel bridge crane was designed. Based on refueling operations, the spent fuel bridge crane is expected to perform about 736 lifts per fuel cycle, 90 lifts per fuel cycle once dry cask storage

has commenced,193 initial core loading lifts, and 160 lifts moving the storage pool gate, for an estimated 66,433 significant crane lifts. The staff finds that this estimated number of lift cycles is less than the 100,000 permissible cycles for a CMAA 70 Class B crane and, therefore, is acceptable.

The staff reviewed LRA Section 4.7.1 and FSAR-SP Section 9.1.4, "Fuel Handling System," and confirmed that the refueling machine is used to load, unload, and move fuel assemblies within the reactor core and to transfer fuel to and from the fuel transfer tube. LRA Table 4.7-1 shows that the estimated number of lifts for 60 years of operation will not exceed the maximum number of lifts for which the refueling machine was designed. Considering there are 193 assemblies in the core, roughly 400 lifts are estimated each refueling outage. Assuming 80 refuel cycles of the 60 years of operation, the estimated maximum significant crane lifts for the refueling machine is 32,000 lifts. The staff finds that this estimated number of lift cycles is less than the 100,000 permissible cycles for CMAA 70 and, therefore, is acceptable.

The staff finds that the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the analyses for the containment polar crane, fuel building cask handling crane, spent fuel pool bridge crane, and refueling machine CMAA 70 load cycle limits remain valid for the period of extended operation. Additionally, the applicant meets the acceptance criteria in SRP-LR Section 4.7.2.1 because the applicant has demonstrated that the analyses for the containment polar crane, fuel building cask handling crane, spent fuel pool bridge crane, and refueling machine CMAA load cycle limits remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(i).

4.7.1.3 FSAR Supplement

LRA Section A3.6.1 provides the FSAR supplement summarizing the containment polar crane, fuel building cask handling crane, spent fuel pool bridge crane, and refueling machine CMAA 70 load cycle limits. 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 FSAR 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 verify that it is appropriate, such that later changes can be controlled by 10 CFR 50.59, "Changes, Tests and Experiments," 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 FSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.7.2.2 and is, therefore, acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address CMAA 70 load cycle limits, 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, in accordance with 10 CFR 54.21(c)(1)(i), that the analyses for the containment polar crane, fuel building cask handling crane, spent fuel pool bridge crane, and refueling machine CMAA 70 load cycle limits remain valid for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.2 Inservice Flaw Analyses that Demonstrate Structural Integrity for 40 Years

4.7.2.1 Summary of Technical Information in the Application

LRA Section 4.7.2 describes the TLAA for inservice flaw analyses. The LRA states that inservice flaw growth is identified in the SRP-LR as a potential TLAA and flaws of such size that they cannot be dispositioned through comparison with the ASME Code tables must be analyzed. The LRA states that these analyses depend on a specified number of operating events or years and, therefore, may be TLAAs. The applicant identified three flaw evaluations as discussed here.

Cold Leg Elbow-to-Safe End Weld Flaw Indications. The fatigue crack growth analysis for the cold leg elbow-to-safe end weld flaw indications assumes the design number of transients. The projected transient accumulations show that the numbers of transient cycles are expected to remain within the assumed numbers and, therefore, the analyses are valid through the period of extended operation. The TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

Canopy Seal Weld Overlay. The fracture mechanics crack growth analysis for the CRDM canopy seal weld overlay repairs indicates that the design is adequate for 57 years of operation. Since the repairs were performed in 1992, the repairs are valid through the period of extended operation, until 2049. The TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

Pressurizer SWOL Fatigue Crack Growth Analysis. The pressurizer nozzle structural weld overlays (SWOL), performed in 2007, depend on 40-year fatigue crack growth analyses, which will remain valid until 2047. The projected transient accumulations are expected to remain within the assumed numbers and, therefore, the analyses are valid through the period of extended operation. The TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

4.7.2.2 Staff Evaluation

The staff reviewed the applicant's TLAAs for inservice flaw growth analyses and the corresponding dispositions 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 analysis are reviewed to ensure that the number of assumed cycles would not be exceeded during the period of extended operation.

Cold Leg Elbow-to-Safe End Weld Flaw Indications. LRA Section 4.7.2 states that for the cold leg elbow-to-safe end weld flaw indications, a fatigue crack growth analysis was performed. The LRA also states that the elbow is statically cast stainless steel (SA-351, CF8A) and the GTAWs are subject to thermal aging, but the effects are considered negligible. The applicant concluded that the fracture mechanics analysis did not consider aging effects and is not a TLAA, in accordance with 10 CFR 54.3(a), Criterion 2. The staff noted that the applicant did not justify why the GTAWs are not subject to thermal aging but the effect is considered negligible. The staff also noted that the applicant did not indicate whether the statically cast stainless steel elbow is susceptible to thermal aging and why such a fracture mechanics analysis of the elbow would not be a TLAA in accordance with 10 CFR 54.3.

By letter dated August 6, 2012, the staff issued RAI 4.7.2-2 requesting that the applicant justify why the effect of thermal aging on the GTAWs is considered negligible and justify why the fracture mechanics analysis did not consider the elbow material, which may also be susceptible to thermal aging.

In its response to RAI 4.7.2-2 dated September 6, 2012, the applicant stated that because of the high fracture toughness properties for GTAWs and per ASME Code Section XI, Appendix C, Paragraph C-4210, GTAWs only need to consider the plastic collapse failure mode. The applicant also stated that plastic collapse is prevented by satisfying the IWB-3640 requirements that include a fatigue crack growth analysis. The RAI response also stated that the potential changes in the fracture toughness properties caused by thermal aging would not affect the result fatigue crack growth analysis. Therefore, the applicant concluded that thermal aging can be neglected for GTAWs because thermal aging will not affect the analysis results for the dominant failure mode. The staff noted that NUREG/CR-6428, "Effects of Thermal Aging on Fracture Toughness and Charpy-Impact Strength of Stainless Steel Pipe Welds," May 1996, states that GTAWs exhibit higher fracture resistance than other types of welds. Therefore, the staff finds it reasonable that the effect of thermal aging on GTAWs is considered negligible.

The applicant also stated that the elbow is CASS but is not susceptible to thermal aging, as described in LRA Section 3.1.2.2.6.2, because the molybdenum (less than 0.5 percent) and ferrite (less than 20 percent) content of these fittings and piping pieces are below the industry accepted thermal aging significance threshold. The staff also noted that the staff's recommendations for component susceptibility to thermal aging are provided in the GALL Report AMP XI.M12, which states that the susceptibility to thermal aging embrittlement of CASS materials is determined in terms of casting method, molybdenum content, and ferrite content. The staff noted that in its response to RAI 3.1.1.50-1, dated September 20, 2012, the applicant provided details justifying that its CASS components in the RCS are not susceptible to thermal aging embrittlement. The staff determined that the reactor coolant piping is not subjected to thermal aging. The staff's review of the applicant's response to RAI 3.1.1.50-1 is documented in SER Section 3.1.2.1.1.

The staff finds the applicant's response to RAI 4.7.2-2 acceptable because the applicant provided sufficient justification, as described above, that the GTAW and the elbows of the cold leg elbow-to-safe end weld are not susceptible to thermal aging and, therefore, the fracture mechanic analyses are not TLAAs, in accordance with 10 CFR 54.3. The staff concern in RAI 4.7.2-2 is resolved.

The LRA also indicates that the design numbers of transients assumed to occur over the plant life are consistent with those of FSAR Table 3.9(N)-1SP. However, LRA Section 4.7.2 did not specifically identify the transients that were used in the fatigue crack growth analysis and the staff cannot verify the adequacy of the disposition of the fatigue crack growth TLAA, in accordance with 10 CFR 54.21 (c)(1)(i). By letter dated August 6, 2012, the staff issued RAI 4.7.2-1 requesting the applicant identify all the transients and associated number of cycles that were used in the fatigue crack growth analysis of the cold leg elbow-to-safe end weld flaw indications.

In its response to RAI 4.7.2-1 dated September 6, 2012, the applicant provided a list of all the transients and associated number of cycles used in the fatigue crack growth analysis of the cold leg elbow-to-safe end weld flaw indications. The staff confirmed that those transients are included in LRA Table 4.3-2 and confirmed that the numbers of cycles analyzed in the fatigue crack growth analysis bound the number of cycles projected in LRA Table 4.3-2 for the applicant's plant through 60 years of operation. The staff's evaluation of the applicant's projection methodology for transient cycles is documented in SER Section 4.3.1.2. The staff noted that the 60-year projections listed in LRA Table 4.3-2 are less than the analyzed cycle limit with margin to account unanticipated occurrence of plant transients through the period of extended operation.

The staff finds the applicant's response to RAI 4.7.2-1 acceptable because the applicant confirmed that the transients used as inputs to the fatigue crack growth analysis were listed in LRA 4.3-2, and the 60-year projected cycles in LRA Table 4.3-2 are bounded by the numbers of cycles analyzed in fatigue crack growth analysis. The staff's concern described in RAI 4.7.2-1 is resolved.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the fatigue crack growth analysis for the cold leg elbow-to-safe end weld indications remains valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.3.2.1.5.1 because the cycle limits assumed in the fatigue crack growth analysis will not be exceeded during the period of extended operation based on the 60-year projected cycles and there is margin in the 40-year cycle limits to account for unanticipated occurrence of plant transients during the period of extended operation.

Canopy Seal Weld Overlay. For the canopy seal weld overlay, the applicant stated that the remaining life of the 1992 repair was determined with a fracture mechanics crack growth analysis that accounts for the stress corrosion cracking (SCC) resistance of the repair. The results of the SCC crack growth law are a function of time (e.g., years) and not based on monitored plant events (e.g., plant heatups). The staff noted that the fracture mechanics crack growth analysis for the canopy seal weld overlay repairs was assumed for 57 years of operation. In addition, since the repairs were performed in 1992, based on the analysis, the repairs are valid until 2049. The staff noted that the period of extended operation will be through October 2044 and the analysis remains valid during the period of extended operation.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the fracture mechanics crack growth analysis for the canopy seal weld overlay remains valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.3.2.1.5.1 because the 57-year time limit established by the existing fracture mechanics crack growth analysis extends beyond the period of extended operation.

Pressurizer SWOL Fatigue Crack Growth Analysis. For the pressurizer SWOL, LRA Section 4.7.2 states that a fatigue crack growth evaluation was performed to support the relief request to perform preemptive SWOL on the pressurizer spray, relief, and safety nozzles.

The LRA states that the 40-year design numbers of transients were used in the fatigue crack growth analysis. However, LRA Section 4.7.2 did not specifically identify the transients that were used in this analysis and the staff cannot verify the adequacy of the disposition of the TLAA in accordance with 10 CFR 54.21 (c)(1)(i). By letter dated August 6, 2012, the staff issued RAI 4.7.2-3 requesting the applicant identify all the transients and associated number of cycles that were used in this fatigue crack growth analysis. The staff also requested the applicant to:

> [i]dentify the baseline number of occurrences for each transient from 2007 to January 2011. In addition, provide and justify the projected occurrences for each transient from January 2011 to 2043 to support the TLAAs disposition, in accordance with 10 CFR 54.21 (c)(1)(i). Alternatively, justify that the number of occurrences between 1983 to January 2011 is a conservative representation of the number of occurrences between 2007 to January 2011.

In its response letter dated September 6, 2012, the applicant listed in Table 1, "Transients Used in the Fatigue Crack Growth Analyses," of Enclosure 1, all transients and associated number of cycles used in the fatigue crack growth analysis of the pressurizer SWOL. The applicant also

stated that all the transients in Table 1, Enclosure 1, are included in LRA Table 4.3-2. The applicant further stated that Table 1, Enclosure 1, "provides the baseline and projected numbers for all transients included in the fatigue crack growth analyses supporting the Callaway pressurizer (SWOL) repairs." The applicant further stated that "the transients will not exceed the design numbers; therefore, the analyses will remain valid through the period of extended operation and the TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(i)." The staff confirmed that those transients are included in LRA Table 4.3-2 and confirmed that the numbers of cycles analyzed in the analysis bound the number of cycles projected in LRA Table 4.3-2 for the applicant's plant through 60 years of operation. The staff noted that the 60-year projections provided in LRA Table 4.3-2 are less than the analyzed cycle limit, with margin to account unanticipated occurrence of plant transients through the period of extended operation. The staff's evaluation of the projection methodology is documented in SER Section 4.3.1.2.

The staff finds the applicant's response to RAI 4.7.2-3 acceptable because the applicant confirmed that the transients used as inputs in the fatigue crack growth analyses were listed in LRA 4.3-2 and the 60-year projected cycles in LRA Table 4.3-2 are bounded by the numbers of cycles analyzed in fatigue crack growth analysis. The staff's concern described in RAI 4.7.2-3 is resolved.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the fatigue crack growth analysis for the pressurizer SWOL remains valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.3.2.1.5.1 because the cycle limits assumed in the fatigue crack growth analysis will not be exceeded during the period of extended operation based on the 60-year projected cycles and there is margin in the 40-year cycle limits to account for unanticipated occurrence of plant transients during the period of extended operation.

4.7.2.3 FSAR Supplement

LRA Section A3.6.2 provides the FSAR supplement summary description of the applicant's TLAA evaluation of the fatigue crack growth analyses associated with the cold leg elbow-to-safe end weld flaw indications, canopy seal weld overlay, and pressurizer SWOL. The staff reviewed LRA Section A3.6.2 consistent with the review procedures in SRP-LR Section 4.3.3.2, which states that the information to be included in the FSAR supplement should include a summary description of the evaluation of the TLAAs and describes how the TLAAs have been dispositioned for the period of extended operation.

Based on its review of the FSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.3.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the fatigue crack analyses, as required by 10 CFR 54.21(d).

4.7.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(i), that its fatigue crack analyses associated with the cold leg elbow-to-safe end weld flaw indications, canopy seal weld overlay, and pressurizer SWOL remain valid for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.3 Corrosion Analysis of the Reactor Vessel Cladding Indications

4.7.3.1 Summary of Technical Information in the Application

LRA Section 4.7.3 describes the applicant's assessment for corrosion analysis of the reactor vessel cladding indications. The LRA states that two areas were identified during RFO 13 (spring 2004) and RFO 15 (spring 2007) where the RPV low-alloy steel has been left exposed to the reactor coolant. The evaluation of these indications considered a plant life of 40 years, which includes 20 years under the current license, plus 20 years for the period of extended operation. The LRA states that the vessel minimum wall thickness evaluation demonstrated that the wall thickness minus the maximum degraded area depth meets the criterion of ASME Code Section III, NB-3324.2.

The applicant dispositioned the corrosion analysis of the reactor vessel cladding indications TLAA, in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid for the period of extended operation.

4.7.3.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the corrosion analysis of the reactor vessel cladding indications and the corresponding disposition, consistent with the review procedures in SRP-LR Section 4.7.3.1.1, which state that the existing analyses should be shown to be bounding during the period of extended operation. The SRP-LR also states that the applicant should show 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 reasonable assurance that the intended functions are maintained for renewal.

LRA Section 4.7.3 states that RPV low-alloy steel has been left exposed to the reactor coolant and that the vessel minimum wall thickness evaluation demonstrated that the wall thickness (13.67 cm or 5.38 in.) minus the maximum degraded area depth (0.71 cm or 0.28 in.) meets the criterion of NB-3324.2 (11 cm or 4.33 in.). The amount of corrosion was calculated assuming a corrosion rate of 0.003 cm (0.001 in)/yr for normal operating condition, 0.038 cm (0.015 in.)/yr for an outage, and 0.025 cm (0.010 in.)/yr for a startup period after each outage. In addition, the LRA also indicates that assuming an outage corrosion rate for the entire 40-year period would yield 0.15 cm (0.6 in.) of corrosion. The staff noted that the corrosion analysis, which was performed in 2004 with an update in 2007, covered 40 additional years that coincides with the end of the period of extended operation.

The staff noted that the applicant did not provide the thickness of the cladding and whether the wall thickness of 13.67 cm (5.38 in.) includes this cladding thickness; therefore, the staff was not able to determine if the criterion of NB-3324.2 was met. In addition, the staff noted that the applicant has not provided the technical bases regarding the use of the specified corrosion rates for its plant-specific conditions. Furthermore, only the maximum degraded area depth of 0.71 cm (0.28 in.) was discussed with respect to the minimum wall thickness criterion of NB-3324.2; the staff could not verify the adequacy of the disposition of the TLAA in accordance with 10 CFR 54.21(c)(1)(i).

By letter dated August 16, 2012, the staff issued RAI 4.7.3-1 requesting that the applicant justify that the corrosion rate of 0.038 cm (0.015 in.)/yr is bounding for the conditions at the plant. The staff also requested the applicant to confirm that the maximum degraded area depth of 0.71 cm (0.28 in.) was a calculated or measured value at the time the cladding was discovered to be missing. The applicant was also requested to provide additional information from the calculation

to support its conclusion that the wall thickness meets the criterion of NB-3324.2 and to revise the LRA as necessary.

In it response to RAI 4.7.3-1 dated September 20, 2012, the applicant stated that the calculation assumes corrosion rates for three plant conditions (normal operation, refueling, and startup) based on test data referenced in EPRI technical report, "Boric Acid Corrosion Guidebook," Revision 1. The applicant stated that a corrosion rate of less than 0.003 cm (0.001 in)/yr was determined for carbon steel and low-alloy steel in the EPRI technical report based on test condition in deaerated water with 2,500 to 3,000 ppm boron at temperatures up to 310 °C (590 °F). The applicant explained that its plant-specific normal operating conditions are consistent with historical maximum hot full power boric acid concentration of 1,400 ppm and the average RCS temperature is 307 °C (585 °F). Thus, the staff found it reasonable that the applicant used 0.003 cm (0.001 in)/yr for its plant for normal operating conditions corrosion rate in this analysis because the applicant's normal operating conditions are within the bounds of the test conditions.

The applicant explained that, for the plant startup corrosion rate, the test was conducted in the environment that was not deaerated, and no additional oxygen was added during the test. During the test, the specimens were held at 177 °C (350 °F), and the results indicated slightly higher average corrosion rates than 0.025 cm (0.010 in.)/yr. The applicant also explained that, since its plant is required to establish oxygen controls in the RCS before exceeding 121 °C (250 °F), deaerated conditions will be established before exceeding the temperature range of the test data. The staff noted that, since the applicant start-up operation would maintain minimal oxygen content before 121 °C (250 °F), the actual plant condition during start-up is less severe than the test data conditions. Thus, it is reasonable for the applicant to use 0.025 cm (0.010 in.)/yr for startup conditions corrosion rate in this analysis.

The applicant stated that the refueling corrosion rate of 0.038 cm (0.015 in.)/yr was obtained based on a series of tests conducted for low alloy steel immersed in aerated water with 2,500 ppm boron at low temperatures, up to 60 °C (140 °F). The applicant stated that its refueling conditions are consistent with these conditions with nominal refueling boric acid concentration and maximum refueling temperature at 2,500 ppm and 60 °C (140 °F), respectively. The staff noted that since its actual plant condition during refueling is no more severe than the test data conditions, it is reasonable for the applicant to use 0.038 cm (0.015 in.)/yr for refueling conditions corrosion rate in this analysis.

The applicant also stated that, even though its current operation schedules a refueling outage with an average duration of less than 8 weeks every 18 months, it used the outage corrosion rate of 0.038 cm (0.015 in.)/yr for the entire 40-year period such that the resulting wall loss would be 1.5 cm (0.6 in.). The staff finds the applicant use of outage corrosion rate for the entire evaluation period conservative because it assumed a higher corrosion rate than those for normal operation and startup periods.

The applicant also clarified that the minimum design wall thickness of the low-alloy steel reactor vessel bottom head is 13.67 cm (5.38 in.), which does not include the cladding. However, the applicant stated that in its assessment for corrosion of the reactor vessel cladding indications, it conservatively assumed that the nominal cladding thickness of 0.56 cm (0.22 in.) is included in the thickness of 13.67 cm (5.38 in.). The applicant explained that the depth for the defect is approximately 0.35 cm (0.14 in.) based on its ultrasonic testing inspection report and the evaluation conservatively assumed the defect depth to be 0.71cm (0.28 in.). The staff noted that the assumed depth of 0.71cm (0.28 in.) is greater than the cladding thickness of 0.56 cm

(0.22 in.), which supports the applicant's statement that the low-alloy steel has been left exposed to reactor coolant. The staff finds the applicant's assumption on the damage depth of 0.71cm (0.28 in.) reasonable because it doubled the approximated damage depth to allow additional margin in the evaluation.

The applicant further explained that adding the 1.5 cm (0.6 in.) wall loss due to corrosion to the assumed defect depth of 0.71 cm (0.28 in.) would still leave the reactor wall thickness at 11.4 cm (4.5 in.) (13.67 cm – 0.71 cm – 1.5 cm = 11.4 cm) (5.38 in. – 0.28 in. - 0.6 in. = 4.5 in.). The applicant concluded that the requirement minimum wall thickness based on the criterion of NB-3324.2 of 11 cm (4.329 in.) is satisfied.

The staff finds the applicant's response to RAI 4.7.3-1 acceptable because the applicant (1) justified that corrosion rate assumed in the analysis is bounding for the conditions at the plant, (2) clarified the cladding thickness and whether the thickness of the vessel wall include the cladding, and (3) calculated and identified the remaining wall thickness at year 2044 (end of the period of extended operation) to support its TLAA disposition. The staff concerns described in RAI 4.7.3-1 are resolved.

As part of RAI B2.1.5-4b, dated January 30, 2013, the staff requested the applicant provide information regarding the aging management aspect of these reactor vessel cladding indications. Specifically, the applicant was requested to provide the inspection method to manage the degradation of the cladding and reactor vessel. In its response to RAI B2.1.5-4b, dated February 14, 2013, the applicant stated that during the upcoming refueling outage (RFO) (Spring 2013), an ultrasonic examination of each indication in the reactor vessel wall is planned and surface profile data will be collected in the area of the indication and the surrounding cladding. The applicant also stated that future thickness measurements of the reactor vessel wall indications will be performed as part of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The staff's review of the applicant's response to RAI B2.1.5-4b is documented in SER Section 3.0.3.1.4.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the corrosion analysis of the reactor vessel cladding indications remains 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 (1) its corrosion rate assumption is conservative in addressing the relevant aging effect of corrosion, and (2) the design criterion of minimum wall thickness of 11 cm (4.329 in.) is maintained.

4.7.3.3 FSAR Supplement

LRA Section A3.6.3, as amended by letter dated September 20, 2012, provides the FSAR supplement summary description of the applicant's TLAA evaluation of the corrosion analysis of the reactor vessel cladding indications. 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 information to be included in the FSAR supplement should include a summary description of the evaluation of the TLAA and describes how the TLAA has been dispositioned for the period of extended operation.

Based on its review of the FSAR supplement, as amended by letter dated September 20, 2012, the staff finds it meets the acceptance criteria in SRP-LR Section 4.7.2.2, and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the corrosion analysis of the reactor vessel cladding indications, 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, in accordance with 10 CFR 54.21(c)(1)(i), that the corrosion analysis of the reactor vessel cladding indications remains valid for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.4 Reactor Vessel Underclad Cracking Analyses

4.7.4.1 Summary of Technical Information in the Application

LRA Section 4.7.4 describes the applicant's assessment of underclad cracking of the reactor vessel. The applicant stated that Westinghouse prepared a topical report on underclad cracking that included fatigue crack growth analyses and ASME Code Section XI allowable flaw size evaluations for typical Westinghouse vessels. The topical report concluded that the expected maximum flaw predicted by the crack growth analyses was less than the ASME Code Section XI allowable flaw size. The staff's safety evaluation of the topical report determined that it may be incorporated by reference in an LRA, provided that the analysis is applicable to the applicant's plant. However, the applicant stated that no underclad cracks have been discovered and this analysis is not invoked in its CLB, therefore it is not a TLAA by 10 CFR 54.3(a), Criterion 6.

4.7.4.2 Staff Evaluation

The staff reviewed LRA Section 4.7.4 and the assessment of underclad cracking of the reactor vessel components to verify the applicant's basis for determining there are no applicable TLAAs. The staff reviewed the applicant's evaluation and conclusion consistent with the review procedures in SRP-LR Section 4.1.3, which state that the reviewer should verify that the selected analyses do not meet at least one of the criteria of a TLAA, as defined in 10 CFR 54.3(a).

By letter dated May 3, 2012, the applicant amended LRA Section 4.7.4 to reference Westinghouse Report, WCAP-15338-A, as the basis for managing potential underclad cracking in the reactor vessel components that were made from SA-508, Class 2 alloy steel forging materials. The applicant also identified the fatigue crack growth analysis in WCAP-15338-A as a TLAA for the LRA. The applicant dispositioned this TLAA in accordance with 10 CFR 54.21(c)(1)(i), that this fatigue crack growth analysis remains valid for the period of extended operation.

The staff reviewed the applicant's amended TLAA for underclad cracking of reactor vessel 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 analysis are reviewed to ensure that the number of assumed cycles would not be exceeded during the period of extended operation.

The staff noted that the WCAP-15338-A provides a fatigue crack growth analysis for underclad cracks that are postulated in the internal cladding of SA-508, Class 2 alloy steel components in Westinghouse-designed RPVs. The staff noted that the fatigue crack growth analysis was based on ASME Code Section XI, Appendix A, and evaluated potential RPV underclad flaws over the licensed operating period. The staff's review of the fatigue crack growth analysis is

documented in its Safety Evaluation of WCAP-15338, "A Review of Cracking Associated with Weld Deposited Cladding In Operating PWR Plants," dated October 15, 2001 (ADAMS Accession No. ML012890230).

The staff's SE indicated that a license renewal applicant must address two action items if WCAP-15338 is referenced for use in the LRA. The first action item states that the applicant should demonstrate that the design cycles assumed in WCAP-15338-A bound the number of cycles for 60 years of operation at the plant. The second action item states that the applicant should provide a summary description of the TLAA evaluation in the FSAR supplement.

The staff noted that Westinghouse considered the entire set of design basis transients to assess the impact on the postulated flaw sizes in the WCAP-15338 analysis. The staff further confirmed that those design basis transients considered in WCAP-15338 are included in LRA Table 4.3-2, the transients monitored by the applicant's Fatigue Monitoring Program. The staff also confirmed that the number of cycles analyzed in WCAP-15338-A is bounding for the number of cycles projected for Callaway for 60 years of operation, as shown LRA Table 4.3-2. Thus, the applicant addressed the first action item and demonstrated that the WCAP-15338-A bound the number of cycles for 60 years of operation for its plant. The staff's evaluation of the applicant's projection methodology is documented in SER Section 4.3.1.2. The staff noted that the applicant, by letter dated May 3, 2012, revised its LRA to include LRA Section A3.6.4, which is the FSAR supplement for the TLAA related to underclad cracking of RPV components and WCAP-15338. Thus, the applicant addressed the second action item and provided a summary description of the TLAA evaluation in the FSAR supplement. The staff's review of LRA Section A3.6.4 is documented in SER Section 4.7.4.3.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the analysis for underclad cracking of the reactor vessel components remains valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.3.2.1.5.1 because the fatigue crack growth analysis demonstrated that the full set of design transients were considered and the design cycle limits will not be exceeded during the period of extended operation.

4.7.4.3 FSAR Supplement

LRA Section A3.6.4, as amended by letter dated May 3, 2012, provides the FSAR supplement summarizing the TLAA for underclad cracking of the reactor vessel components. The staff reviewed LRA Section A3.6.4 consistent with the review procedures in SRP-LR Section 4.3.3.2, which states that the information to be included in the FSAR supplement should include a summary description of the evaluation of the metal fatigue TLAA.

Based on its review of the FSAR 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 reactor vessel 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, in accordance with 10 CFR 54.21(c)(1)(i), that the analysis for underclad cracking of the reactor vessel components remains valid for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.5 Reactor Coolant Pump Flywheel Fatigue 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 analysis. The LRA states that a fatigue crack growth analysis demonstrates that 6,000 start-stop cycles (over an assumed 60-year life) will produce an acceptable extension of the crack. The evaluation is based on the 60-year operating period. The LRA states that the 6,000 events in Callaway's fatigue flaw growth are based on the sum of the RCP start-stop cycles in FSAR Table 3.9(N)-1 SP, multiplied by 1.5, which is the general design number of events for the Nuclear Steam Supply System extrapolated to 60 years. The LRA states that only 220 RCP start-stop events are projected to occur in 60 years. Therefore, 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

The staff reviewed the applicant's TLAA for RCP flywheel 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, which states that the existing analyses should be shown to be bounding during the period of extended operation. The SRP-LR also states that the applicant should show 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 reasonable assurance that the intended functions are maintained for renewal.

The staff noted that the applicant is relying on the flaw growth analysis referenced in "Transmittal of WCAP-15666, 'Extension of Reactor Coolant Pump Motor Flywheel Examination,' Non-Proprietary Class 3 (MUHP-3043)," dated August 24, 2001, (ADAMS Accession No. ML012420149) that assumed 6,000 start-stop cycles for the RCP for a 60-year operating period. The staff confirmed that the NRC endorsed the methodology and results in its "Safety Evaluation of Topical Report WCAP-15666, 'Extension of Reactor Coolant Pump Motor Flywheel Examination,'" dated May 5, 2003 (ADAMS Accession No. ML031250595). LRA Table 4.3-2 shows the projected total number of RCP startups and shutdowns for the 60-year projection to be 220 for the most limiting RCP. The staff noted the expected cycles through the period of extended operation to be less than 5 percent of the design limit of 6,000 cycles, which leaves significant margin to account for unanticipated occurrences of the RCP operation.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the fatigue flaw growth analysis for the RCP flywheel remains valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.7.2.1 because the applicant's 60-year projection for the RCP startups and shutdowns demonstrates that the existing analysis remains valid for the period of extended operation.

4.7.5.3 FSAR Supplement

LRA Section A3.6.5, as amended by letter dated May 3, 2012, provides the FSAR supplement summary description of the applicant's TLAA evaluation of the RCP flywheel fatigue crack growth analysis. The staff reviewed LRA Section A3.6.5 consistent with the review procedures in SRP-LR Section 4.7.3.2, which states that the information to be included in the FSAR supplement should include a summary description of the evaluation of the TLAA and describes how the TLAA has been dispositioned for the period of extended operation. The applicant revised the LRA section number from A3.6.4 to A3.6.5 by letter dated May 3, 2012. The staff

reviewed the revisions and noted they were administrative and did not alter the technical content.

Based on its review of the FSAR supplement, as amended by letter dated May 3, 2012, 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, in accordance with 10 CFR 54.21(c)(1)(i), that the RCP flywheel fatigue crack analysis remains valid for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.6 High-Energy Line Break Postulation Based on Fatigue Cumulative Usage Factors

4.7.6.1 Summary of Technical Information in the Application

LRA Section 4.7.6 describes the applicant's TLAA for HELB postulation based on fatigue CUF. The LRA states that the selection of ASME Code Section III, Class 1 piping HELB locations depends on CUFs, which will remain valid as long as the assumed numbers of cycles are not exceeded. Furthermore, it states that the Fatigue Monitoring Program ensures that the analytical bases of the HELB locations are maintained or that a HELB analysis for the new locations with a CUF greater than 0.1 is performed.

The applicant dispositioned the TLAA, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of cracking postulated for HELB locations based on CUF will be adequately managed by the Fatigue Monitoring Program for the period of extended operation.

4.7.6.2 Staff Evaluation

The staff reviewed LRA Section 4.7.6 and the TLAAs for HELB postulation based on fatigue CUF to verify, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging will be adequately managed 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 4.7.3.1.3, which states that the applicant is to identify the structures and components associated with the TLAA and to describe the TLAA with respect to the objectives of the analysis, conditions, assumptions used, acceptance criteria, relevant aging effects, and intended functions of the components or structures in the analysis. It further states that the reviewer is to assess the applicant's AMP to verify that the effects of aging on the intended functions will be adequately managed consistent with the CLB for the period of extended operation.

FSAR Section 3.6.1.1.a SP defines high-energy piping as systems or portions of systems in which the maximum operating temperature exceeds 93 °C (200 °F) or the maximum operating pressure exceeds 275 psig during normal plant conditions. The staff noted that the pipe break identification basis in FSAR Section 3.6.2.1.1 SP is defined in a manner that conforms to the pipe break identification criteria in NRC Branch Technical Position MEB 3-1. The staff noted that a given location is identified as a line break location if it was a high-energy line location that

satisfied the criteria in FSAR Section 3.6.1.1.a SP. One such criterion is that intermediate ASME Code Class 1 piping locations (i.e., locations between terminal ends) with design basis CUF values exceeding a value of 0.1 are identified as line break locations. The staff noted that the postulations of break locations based on CUFs are TLAAs because they are dependent on an assumed number of cycles expected for the design of the plant. FSAR Section 3.6.2.1.1.a SP also indicated that breaks are eliminated from RCS primary loops, the accumulator and RHR lines because of the approved application of a LBB methodology.

The applicant credits the Fatigue Monitoring Program to manage metal fatigue of these postulated HELB locations 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 HELB postulation evaluation remains valid. The staff also noted that the applicant enhanced the "corrective actions" program element in its Fatigue Monitoring Program to indicate that when a cycle counting action limit is reached, action will be taken to ensure the analytical bases of the HELB locations are maintained. The staff determined that the applicant's AMP, when enhanced, 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 Fatigue Monitoring Program and this enhancement is documented in SER Section 3.0.3.2.22.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of cracking postulated for HELB locations based on CUF will be adequately managed for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.7.2.1 because the applicant's Fatigue Monitoring 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 to ensure that the effects of metal fatigue on the intended functions of these postulated HELB locations will be managed during the period of extended operation.

4.7.6.3 FSAR Supplement

LRA Section A3.6.6, as amended by letter dated May 3, 2012, provides the FSAR supplement summarizing the TLAA for HELB postulation based on CUF. The staff reviewed LRA Section A3.6.6, consistent with the review procedures in SRP-LR 4.7.3.2, which states that the information to be included in the FSAR supplement should include a summary description of the evaluation of the TLAA and describe how the TLAA has been dispositioned for the period of extended operation. The applicant revised the LRA section number from A3.6.5 to A3.6.6 by letter dated May 3, 2012. The staff reviewed the revisions and noted that they were administrative and did not alter the technical content.

Based on its review of the FSAR supplement, as amended by letter dated May 3, 2012, 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 TLAA for HELB postulation based on CUF as required by 10 CFR 54.21(d).

4.7.6.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of cracking postulated for HELB locations based on CUF will be adequately managed for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.7 Fatigue Crack Growth Assessment in Support of a Fracture Mechanics Analysis for the Leak-Before-Break Elimination of Dynamic Effects of Piping Failures

4.7.7.1 Summary of Technical Information in the Application

LRA Section 4.7.7 describes the TLAAs for fatigue crack growth and fracture mechanics analyses performed to support LBB application. LBB analyses eliminated postulated breaks in the applicant's reactor coolant loops (RCL), accumulator injection lines, and RHR hot leg suction lines.

Reactor Coolant Loops. The LRA states that the fatigue crack growth analysis associated with the LBB analyses depend on design transient cycle assumptions and will remain valid as long as the assumed numbers of cycles are not exceeded. The LRA also states that the projected transient accumulations show that the numbers of transient cycles are expected to remain within the assumed numbers and therefore the analyses will remain valid for the period of extended operation. Therefore, the TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

Accumulator Injection and Residual Heat Removal Lines. The LRA states that the fatigue crack growth analyses are based on assumed 40-year design transients. The LRA also states that the projected transient accumulations are expected to remain within the assumed numbers and therefore the analyses will remain valid for the period of extended operation. The TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

4.7.7.2 Staff Evaluation

The staff reviewed the applicant's TLAAs for fatigue crack growth and fracture mechanics analyses performed to support LBB and the corresponding dispositions 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 analysis are reviewed to ensure that the number of assumed cycles would not be exceeded during the period of extended operation.

LRA Section 4.7.7 states that the reactor coolant loops piping LBB analyses included a fracture mechanics analysis and a fatigue crack growth assessment. The staff noted that the fracture mechanics analysis accounts for reduction in fracture toughness of the CASS in the primary loops from thermal aging. The LRA indicates that the fracture mechanics analysis in support of the LBB submittal was performed for a reference material with fully-aged fracture toughness material properties. However, the applicant did not indicate whether the RCL piping is susceptible to thermal aging and did not justify why such a fracture mechanics analysis, performed for a reference material with fully-aged fracture toughness material properties, is not a TLAA as defined by 10 CFR 54.3.

By letter dated August 6, 2012, the staff issued RAI 4.7.7-2 requesting the applicant discuss whether the reactor coolant loops piping material is susceptible to thermal aging and justify why the fracture toughness material properties used in the LBB analysis are not time-dependent parameters. The applicant was also requested to justify that the thermal aging data used in the LBB analysis are up-to-date or conservative when compared to the most recent data for the state of the industry if the analysis involves assumption of referenced fracture toughness values.

In its response dated September 6, 2012, the applicant stated that the reactor coolant loops LBB fracture mechanics analysis was performed with the fracture toughness (J_{1C} , T_{mat} and J_{max}) from a reference material, which showed that the reference material values bound the fully aged

fracture toughness properties of the RCPB cast stainless steel material. The applicant stated that it compared the GTAWs prepared with stainless steel filler material against the results of NUREG/CR-6428. In addition, the applicant performed a comparison of the SA-351 Grade CF8A base metal against the results of NUREG/CR-4513, Revision 1, "Estimation of Fracture Toughness of Cast Stainless Steels during Thermal Aging in LWR Systems," dated May 1994. The applicant concluded that fracture toughness properties values were compared to the most recent data for the state of the industry and determined that the data used in the LBB analysis was conservative.

Thus, based on the comparison performed by the applicant, the staff finds that the applicant's calculation remains valid when compared to the most recent available data in NUREG/CR-6428 and NUREG/CR-4513. Furthermore, based on the results of this comparison, the staff finds that there is not a time-dependency for the lower bound fracture toughness value that was assumed for reactor coolant loop piping and fitting.

The applicant also stated that the reactor coolant loop piping material and elbow fittings are SA351 Grade CF8A cast stainless steel. Furthermore, the molybdenum (less than 0.5 percent) and ferrite (less than 20 percent) content of these fittings and piping pieces are below the thermal aging significance threshold. The applicant concluded that thermal aging of its CASS reactor coolant loop piping and fittings is not a concern, as described in LRA Section 3.1.2.2.6.2. The staff noted that GALL Report AMP XI.M12 indicates that, for steels with low molybdenum (less than 0.5 percent) content, only static-cast steels with more than 20 percent ferrite are potentially susceptible to thermal aging embrittlement. The staff's review of the applicant's CASS reactor coolant system piping and components exposed to reactor coolant is documented in SER Section 3.1.2.2.6.2, which determined that these components are not subject to thermal aging embrittlement. Therefore, since reactor coolant loop piping and fitting components are not susceptible to thermal aging embrittlement, the staff finds it reasonable that the applicant does not need to manage this aging effect for the period of extended operation.

In addition, the staff finds it acceptable that the fracture mechanics evaluation in the RCL LBB analysis is not a TLAA, in accordance with 10 CFR 54.3, because it does not involve time-limited assumptions defined by the current operating term.

The staff finds the applicant's response to RAI 4.7.7-2 acceptable because the applicant provided sufficient justification, as described above, that the reactor coolant loops piping material is not susceptible to thermal aging embrittlement, and the analysis performed does not involve time-limited assumptions. The staff concern described in RAI 4.7.2-2 is resolved.

The LRA indicates that the 40-year design numbers of transients were used in the fatigue crack growth analysis for the reactor coolant loop piping. The staff also noted that the 60-year projections provided in LRA Table 4.3-2 are less than the design limit for each transient, with margin to account unanticipated occurrence of plant transients through the period of extended operation. The staff's evaluation of the projection methodology is documented in SER Section 4.3.1.2.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the fatigue crack growth analysis that supports the reactor coolant loop piping LBB analyses remain valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.3.2.1.5.1 because the 40-year cycle limits assumed in these fatigue crack growth evaluations will not be exceeded during the period of extended operation based on the

60-year projected cycles and because there is margin in the 40-year cycle limits to account for unanticipated occurrence of plant transients during the period of extended operation.

LRA Section 4.7.7 states that the LBB analysis for the accumulator injection and RHR lines included a fracture mechanics and a fatigue crack growth analysis. The applicant stated these lines and associated fittings are forged and are not subject to thermal aging. Therefore, the fracture mechanics analyses are not TLAAs by 10 CFR 54.3(a), Criterion 2. The staff noted that, as described in the GALL Report, CASS may exhibit significant embrittlement (reduction in fracture toughness) because of thermal aging. The staff noted that, since the accumulator injection and RHR lines included associated fittings that are forged, thermal aging embrittlement is not a concern. The staff evaluation of the applicant's absence of TLAA for these fracture mechanics analyses is documented in SER Section 4.1.2.1.2.

The LRA states that normal operating and upset thermal transients were selected as input to the fatigue crack growth evaluation of the LBB analyses. However, LRA Section 4.7.7 did not specifically identify the transients that were used in the analysis, and the staff cannot verify the adequacy of the disposition of the TLAA in accordance with 10 CFR 54.21(c)(1)(i). By letter dated August 6, 2012, the staff issued RAI 4.7.7-1 requesting the applicant identify all the transients and associated number of cycles that were used in the fatigue crack growth analysis for the accumulator injection and RHR lines.

In its response to 4.7.7-1 dated September 6, 2012, the applicant provided a list of the transients and associated number of cycles used in the LBB fatigue crack growth analyses for the accumulator injection and RHR lines. The staff confirmed that those transients are included in LRA Table 4.3-2 and confirmed that the numbers of cycles analyzed in the fatigue crack growth analysis bound the number of cycles projected in LRA Table 4.3-2 for the applicant's plant through 60 years of operation. The staff noted that the 60-year projections provided in LRA Table 4.3-2 are less than the analyzed cycle limit, with margin to account for unanticipated occurrences of plant transients through the period of extended operation. The staff's evaluation of the projection methodology is documented in SER Section 4.3.1.2.

The staff finds the applicant's response to RAI 4.7.7-1 acceptable because the applicant confirmed that the transients used as inputs in the fatigue crack growth analyses were listed in LRA Table 4.3-2, and the 60-year projected cycles in LRA Table 4.3-2 are bounded by the numbers of cycles analyzed in these fatigue crack growth analysis. The staff concern described in RAI 4.7.7-1 is resolved.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the fatigue crack growth analysis for the accumulator injection and RHR lines remains valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.3.2.1.5.1 because the cycle limits established in the fatigue crack growth evaluation will not be exceeded during the period of extended operation based on the 60-year projected cycles. The staff also finds there is margin in the 40-year cycle limits to account for unanticipated occurrence of plant transients during the period of extended operation.

4.7.7.3 FSAR Supplement

LRA Section A3.6.7, as amended by letter dated May 3, 2012, provides the FSAR supplement summary description of the applicant's TLAAs evaluation of the fatigue crack growth analyses and fracture mechanics analyses associated with the LBB. The staff reviewed LRA Section A3.6.7, consistent with the review procedures in SRP-LR Section 4.3.3.2, which states that the information to be included in the FSAR supplement should include a summary

description of the evaluation of the TLAAs and describe how the TLAAs have been dispositioned for the period of extended operation. The applicant revised the LRA section number from A3.6.6 to A3.6.7 by letter dated May 3, 2012. The staff reviewed the revisions and noted that they were administrative and did not alter the technical content.

Based on its review of the FSAR supplement, as amended by letter dated May 3, 2012, 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 fatigue crack analyses, as required by 10 CFR 54.21(d).

4.7.7.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(i), that the fatigue crack growth analyses and fracture mechanics analyses associated with LBB remain valid for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAAs evaluation, as required by 10 CFR 54.21(d).

4.7.8 Replacement Class 3 Buried Piping

4.7.8.1 Summary of Technical Information in the Application

LRA Section 4.7.8 describes the applicant's TLAA for its replacement essential service water (ESW) piping from the pump house to the control building and from the control building to the ultimate heat sink (UHS) cooling tower with high-density polyethylene (HDPE) piping. The applicant submitted a relief request as an alternative to ASME Code Section XI to allow installation of HDPE piping in lieu of metallic piping. The LRA states that the acceptance criteria in the analysis of the design pressure, longitudinal stress, and thermal loads; as well as the modulus of elasticity used as input to the analysis of the soil and surcharge loads and thermal loads were all based on a 40-year life. The LRA also states that the replacement of the buried piping began in 2008 and, therefore, a 40-year life exceeds the end of the period of extended operation, October 2044.

The applicant dispositioned the TLAA for the replacement ESW piping, in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

4.7.8.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the replacement ESW piping 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. The procedures state that the applicant should show that the conditions and assumptions used in the analysis already address the relevant aging effects for the period of extended operation and that acceptance criteria are maintained to provide reasonable assurance that the intended function(s) is maintained for renewal.

The staff noted that calculations 2007-13241, Revision 1, "Minimum Wall Thickness for ESW Buried HDPE Piping," dated September 3, 2008, (ADAMS Accession No. ML082630799) and 2007-1670, "Analysis of Buried HDPE Piping," dated December 21, 2007, (ADAMS Accession No. ML081220483), use a 40-year normal service life and include a 30-day duration of peak post-accident conditions. The staff also noted that LRA Section 4.7.8 states that the replacement of the buried ESW piping with HDPE material began in 2008. The staff further noted that the design analysis for 40 years surpasses the end of the period of extended

operation for the applicant's site, October 2044; however, based on a review of the FSAR, the staff noted that other transient scenarios less severe than the postulated 30-day transient (e.g., inadvertent opening of a pressurizer safety or relief valve, minor steam system piping failure) could result in operating parameters that are higher than those for the 40-year life parameters and for which multiple frequencies could occur in the plant's expected life (i.e., 60 years). These potential other transients are not reflected in the calculations. By letter dated July 5, 2012, the staff issued RAI 4.7.8-1 requesting the applicant to state whether other transients should have been included in the HDPE analyses and, if so, state the basis for why these additional transients do not impact the 40-year life of the piping.

In its response to RAI 4.7.8-1 dated August 6, 2012, the applicant stated that only the following transients result in a release of energy to the containment environment:

- inadvertent opening of a steam generator relief or safety valve (Condition II, FSAR Chapter 15.1.4)
- inadvertent opening of a pressurizer safety or relief valve (Condition II, FSAR Chapter 15.6.1)
- break in instrument line or other lines from RCPB that penetrate containment (Condition II, FSAR Chapter 15.6.2)
- loss-of-coolant accidents resulting from a spectrum of postulated piping breaks within the RCPB (small break) (Condition III, FSAR 15.6.5)
- steam system piping failure (Condition III, FSAR 15.1.5)

In its response the applicant also stated that:

> The Condition II transients will not result in the ESW return piping exceeding its normal design temperature of [41 °C] (105 °F). The vent paths for the Condition II transients do not discharge to the containment atmosphere and would not increase the containment temperature. Therefore, an increase to the ESW return piping temperature would not be expected. Even if conditions resulted in a release to the containment atmosphere (e.g. blown pressurizer relief tank rupture disk), the accident requires that the [RCS] be at normal operating pressure (NOP). With the RCS at NOP, the RHR system would not be aligned to the RCS. Since the RHR system accounts for most of the heat load on the ESW system; there would be sufficient heat removal capacity to prevent the ESW return piping from exceeding its normal design temperature of [41 °C] (105° F).
>
> Condition III transients occur very infrequently during the life of the plant but may result in the ESW water increasing to greater than the normal design temperature of [41 °C] (105° F). The design basis assumes five small LOCA events and five small steam line break events. The ESW return piping temperature during these Condition III transients would be much closer to the normal design temperature versus the post-accident design temperature of [79 °C] (175 °F). The large break LOCA event itself only results in an ESW temperature of [60 °C] (140 °F), and the mass and energy released during a small break event is a fraction of the release during a design basis event. The peak post-LOCA ESW temperature will only be short-lived, and the long-term post-LOCA discharge temperature will be significantly lower. Given that the maximum ESW temperature and the duration at the maximum temperature were analyzed at a much greater value than those

actually expected; the current analysis is sufficient to account for the Condition III transients.

The staff finds the applicant's response acceptable because, based on a review of all operating transients in FSAR Section 15, none exceed the design limits in the calculations for minimum wall thickness and the stress analyses for the HDPE piping. The staff's concern described in RAI 4.7.8-1 is resolved.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the analyses for the replacement ESW piping remain valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.7.2.1 because, as documented in the above referenced calculations and response to RAI 4.7.8-1, the stress evaluations are acceptable for 40 years, which, in the case of the applicant's site, will surpass the period of extended operation. The staff noted that the applicant will be required to submit subsequent relief requests in accordance with 10 CFR 50.55a at the start of each subsequent inservice inspection interval in order to continue to allow use of the HDPE piping in lieu of metallic piping.

4.7.8.3 FSAR Supplement

LRA Section A3.6.8, as amended by letter dated May 3, 2012, provides the FSAR supplement summarizing the replacement Class 3 buried piping. The staff reviewed LRA Section A3.6.8, consistent with the review procedures in SRP-LR Section 4.7.3.2, which states that each such summary description should contain information that the TLAAs have been dispositioned for the period of extended operation and should have sufficient detail to ensure that later changes can be controlled by 10 CFR 50.59. The applicant revised the LRA section number from A3.6.7 to A3.6.8 by letter dated May 3, 2012. The staff reviewed the revisions and noted that they were administrative and did not alter the technical content.

Based on its review of the FSAR supplement, as amended by letter dated May 3, 2012, the staff finds it meets the acceptance criteria in SRP-LR Section 4.7.2.2, and is therefore acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the replacement Class 3 buried piping, as required by 10 CFR 54.21(d).

4.7.8.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(i), that the analyses for the replacement Class 3 buried piping remain valid for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.9 Replacement Steam Generator Tube Wear

4.7.9.1 Summary of Technical Information in the Application

LRA Section 4.7.9 describes the applicant's TLAA for replacement steam generator tube wear. The applicant stated that for the replacement steam generators, the time-averaged wear rates at the tube support locations were analyzed due to the impact or sliding motion of the tubes against their supports. The LRA also states that this analysis assumed a cumulative operating service life of 45 years and compared the calculated maximum wear (0.010 in.) to the maximum allowable wear of 40 percent of the tube wall thickness (0.0156 in.). In addition, the LRA states

that since the 45-year design life of the RSG tubes extends beyond the period of extended operation, the design of the replacement steam generator tubes is valid through the period of extended operation. The applicant dispositioned the TLAA for the steam generator tube wear in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid for the period of extended operation.

4.7.9.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the steam generator tube wear and the corresponding disposition of 10 CFR 54.21(c)(1)(i), consistent with the review procedures in SRP-LR Section 4.7.3, which state that for certain applicants, plant-specific analyses may meet the definition of a TLAA as given in 10 CFR 54.3. SRP-LR Section 4.7.3 also states that the review of these TLAAs provides the assurance that the aging effect is properly addressed through the period of extended operation.

LRA Section B2.1.9, "Steam Generators," indicates that the previous steam generators were replaced in Fall 2005 (RFO 14). LRA Section 4.7.9 states that the TLAA analysis assumed a cumulative operating service of 45 years. LRA Section 4.7.9 also compared the calculated maximum wear of 0.010 in. to the maximum allowable wear of 40 percent of the tube wall thickness, 0.0156 in.

The staff noted that by letter dated May 17, 2012, the applicant submitted to the NRC the "Callaway Energy Center Steam Generator Tube Inspection Report." Section 4.0 of the inspection report addresses the results of the applicant's in-service inspection of the steam generators, which was conducted during RFO 18 (corresponding to 6 years of operation of the steam generators). The following summarizes the inspection results and related information for the tube wear observed in the four replacement steam generators as addressed in Table 2 of the steam generator inspection report:

- Callaway's plugging limit for the steam generator tubes was set at 28 percent through-wall, conservatively, for the next three cycles (Cycles 19, 20, and 21).
- A total of 258 steam generator tubes indicated wear. A total of 232 tubes indicated anti-vibration bar (AVB) wear, and 28 tubes indicated tube support plate (TSP) wear.
- Based on the inspection results, a total of 29 tubes were plugged due to AVB wear

In its review, the staff noted that some of the actual measured tube wear indications exceeded the calculated maximum wear (0.010 in.). Therefore, the staff needed additional information to justify the validity of the applicant's TLAA and its disposition. By letter dated August 16, 2012, the staff issued RAI 4.7.9-2 requesting that the applicant justify why the applicant's TLAA is valid even though some of the steam generator tubes indicated wear greater than the calculated maximum wear for 45 years (0.010 in. for 45 years). The staff also requested that if necessary, the applicant identify any impact of actual measured wear on its analysis, and revise the TLAA accordingly.

In its response dated September 20, 2012, the applicant stated that the AVB wear is the most active wear mechanism in its steam generators, as observed by the steam generator tube inspections, but only one percent (232 out of 23,488) of the steam generator tubes show indications of AVB wear.

In addition, the applicant stated that all wear indications are justified for continued operation until the next scheduled inspection, typically 3 cycles, by establishing a wear rate based on

measured data. The applicant stated that 30 tubes out of a total 23,488 tubes were plugged for aging management, including one tube that was plugged pre-service. The applicant further stated that since the wear analysis describes the wear experienced by the typical steam generator tube, and since all tubes with excessive wear are removed from service, the TLAA will remain valid for the period of extended operation. The applicant stated that excessive wear is defined as tube wear exceeding the TS 5.5.9.c tube plugging criterion of 40 percent through-wall thickness, as incorporated in the Steam Generators Program.

In addition to its response above, the applicant also changed the disposition of this TLAA to 10 CFR 54.21(c)(1)(iii), and stated that the effects of aging on the intended function(s) will be adequately managed for the period of extended operation using the Steam Generators Program. The applicant also revised LRA Sections 4.7.9 and A3.6.9 to reflect the revised TLAA disposition, consistent with 10 CFR 54.21(c)(1)(iii). The staff's evaluation of the Steam Generators Program is discussed in SER Section 3.0.3.1.7.

The applicant stated that the Steam Generators Program detects flaws in tubing, plugs, and tube supports needed to maintain tube integrity. The applicant also stated that assessment of tube integrity is performed in accordance with plant TS and the program implementing procedures. In addition, the applicant stated that plugs and tube supports with aging indications are evaluated for corrective actions, in accordance with the applicant's Corrective Action Program and the Steam Generators Program. The applicant further stated that, therefore, the steam generator tube wear associated with this TLAA will be adequately managed for the period of extended operation.

In its review, the staff noted the applicant's explanation regarding AVB wear and that the TLAA's disposition was changed to 10 CFR 54.21(c)(1)(iii), indicating excessive tube wear will be managed by the Steam Generators Program.

However, the staff also noted that the total number of the steam generator tubes (i.e., 23,488), described in the applicant's response is not consistent with the total number of the tubes (22,144) in Table 1 of the applicant's inspection report, dated May 17, 2012. In addition, the applicant's response does not clearly address the number of the steam generator tubes that show wear indications due to TSP wear. Therefore, the staff needed confirmation on the actual total number of steam generator tubes.

By letter dated November 21, 2012, the staff issued RAI 4.7.9-2a requesting that the applicant clarify the total number of steam generator tubes. The staff also requested that the applicant confirm if a total of 258 steam generator tubes have wear indications because of AVB wear and TSP wear, as described in the applicant's inspection report dated May 17, 2012.

In its response dated December 13, 2012, the applicant stated that there are 5,872 tubes in each steam generator, for a total of 23,488 tubes. The applicant also clarified that the number provided in the inspection report dated May 17, 2012 is a summary of the number of tubes (22,143) that were eddy current tested during RFO 18. The applicant also stated that Table 2 of the inspection report dated May 17, 2012, correctly presents the number of tube support plate indications and there are a total of 258 steam generator tubes that show wear indications because of AVB wear or TSP wear. The staff finds the applicant's response acceptable because the applicant clarified that the total number of the steam generator tubes are 23,488 and a total of 258 steam generator tubes show wear indications because of AVB wear or TSP wear. The staff's concerns described in RAIs 4.7.9-2 and 4.7.9-2a are resolved.

LRA Section 4.7.9 indicates that the applicant's TLAA analyzes steam generator tube wear caused by the impact or sliding motion of the tubes against their supports. In comparison, the recent industry operating experience indicates that steam generator tubes may be subject to tube-to-tube wear, as well as tube wear against their support structures. However, LRA Section 4.7.9 did not indicate that the applicant's TLAA considered tube-to-tube wear as one of the mechanisms that could cause steam generator tube wear. By letter dated August 16, 2012, the staff issued RAI 4.7.9-3 requesting that the applicant provide its technical basis for why the TLAA did not consider tube-to-tube wear as one of the wear mechanisms.

In its response dated September 20, 2012, the applicant stated that the steam generators, which have experienced tube-to-tube wear in the industry, are from a different manufacturer than the manufacturer of Callaway's steam generators. The applicant further stated that Callaway has a different nuclear steam supply system design (AREVA-manufactured Westinghouse 4-loop design) from the Combustion Engineering 2-loop design that experienced steam generator tube-to-tube wear. The applicant also stated that a review of its steam generator inspections confirmed that Callaway steam generator tubes are not exhibiting signs of tube-to-tube proximity or contact. The staff finds the applicant's response acceptable because the applicant clarified that the manufacturer of its steam generators is different from the manufacturer of the steam generators that showed tube-to-tube wear and the applicant's inspection results confirm that tube-to-tube wear has not occurred in the steam generators at Callaway. In addition, the staff finds that the applicant's Steam Generators Program adequately manages steam generator wear by performing periodic inspections of the tubes; assessment of the inspection results; and plugging and repair activities as necessary. Therefore, the staff's concern described in RAI 4.7.9-3 is resolved.

In its review, the staff also noted that industry operating experience indicates that clogging of TSP holes may increase steam generator tube wear. In comparison, LRA Section 4.7.9 does not clearly indicate if the applicant considered the potential adverse effect of clogging of TSP holes in its tube wear calculations. By letter dated August 16, 2012, the staff issued RAI 4.7.9-4 requesting that the applicant clarify if its TLAA considers the potential adverse effect of clogging of TSP holes on steam generator tube wear.

In its response dated September 20, 2012, the applicant stated that the clogging of the holes at the TSP is taken into consideration in the tube wear analysis. The applicant also stated that a clogged hole results in a reduced damping ratio for the vibratory system, which is a penalizing effect in the wear analysis, and the phenomenon is considered even though it is rather unlikely to occur. The staff finds the applicant's response acceptable because the applicant clarified that its TLAA considers potential adverse effect of clogging of the TSP holes. The staff's concern described in RAI 4.7.9-4 is resolved.

During the audit, the staff noted that Callaway Action Request (CAR) 200500411 describes the failure of a flow meter component due to flow-accelerated corrosion (FAC) as addressed in RAI B2.1.7-6, dated July 18, 2012. The staff review of the applicant's response to RAI B2.1.7-6 is discussed in SER Section 3.0.3.1.6. The staff also noted that the flow tube, which was separated from its venturi throat, migrated down the pipe and blocked the minimum recirculation flow line. The failed flow meter addressed in the applicant's CAR is not a feedwater flow meter. However, the staff noted that the applicant's feedwater venturi flow meter may be subject to similar aging degradation (e.g., FAC or corrosion product deposits). Degradation of feedwater flow meters may cause flow rate calculation errors or flow correction factor errors, which can lead to reactor overpower conditions because of underestimations of feedwater flow rates. In turn, reactor overpower conditions can increase steam generator tube wear.

Therefore, the staff needed to clarify if the applicant considered the potential analysis input errors associated with flow rate calculations or flow correction factors, which might affect the TLAA results. By letter dated August 16, 2012, the staff issued RAI 4.7.9-5 requesting that the applicant provide additional information to clarify if its TLAA considers feedwater flow rate calculation errors or flow correction factor errors as part of the analysis.

In its response dated September 20, 2012, the applicant stated that its analysis includes a 2 percent measurement uncertainty. In its review of the applicant's response, the staff noted that the applicant did not clearly address if the 2 percent measurement uncertainty is specifically associated with the feedwater flow rate or reactor thermal power. By letter dated November 21, 2012, the staff issued RAI 4.7.9-5a requesting the applicant to provide additional clarification regarding the 2 percent measurement uncertainty.

In its response dated December 13, 2012, the applicant stated that each feedwater flow venturi is visually inspected and cleaned as necessary at least once per 18 months in accordance with FSAR 16.4.9.1.1. The applicant also stated that these inspections have ensured that the feedwater flow meters adequately maintain the accuracy of the flow coefficient so that Callaway is within the 2 percent measurement uncertainty on the reactor thermal power analysis.

The staff finds the applicant's response acceptable because the applicant clarified that it performs periodic visual inspections of the feedwater flow meters to ensure that the plant is within the 2 percent measurement uncertainty on the reactor thermal power analysis. The staff's concerns described in RAIs 4.7.9-5 and 4.7.9-5a are resolved.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of loss of material caused by wear on the intended functions of the steam generator tubes will be adequately managed by the Steam Generators Program for the period of extended operation. As documented in SER Section 3.0.3.1.7, the staff finds that the Steam Generators Program is adequate to manage steam generator tube wear because it includes periodic inspections of the tubes; assessment of the inspection results; and plugging and repair activities. Additionally, it meets the acceptance criteria in SRP-LR Section 4.7.2.1 because the applicant demonstrated that effects of aging on the intended function(s) of the steam generators tube wear will be adequately managed for the period of extended operation.

4.7.9.3 FSAR Supplement

LRA Section A3.6.9 provides the FSAR supplement summarizing the applicant's TLAA for steam generator tube wear. As amended on September 20, 2012, the applicant amended LRA Section A3.6.9 to reflect TLAA disposition in accordance with 10 CFR 54.21(c)(1)(iii), using the Steam Generators Program for aging management. The applicant also amended the FSAR supplement to clarify that the allowable limit for tube wear is 40 percent through-wall thickness.

The staff reviewed amended LRA Section A3.6.9, consistent with the review procedure in SRP-LR Section 4.7.3.2, which states the FSAR summary description is reviewed to verify that it is appropriate, such that later changes can be controlled by 10 CFR 50.59. The SRP-LR also states that the description should contain information that the TLAAs have been dispositioned for the period of extended operation.

Based on its review of the FSAR supplement, as amended by letter dated September 20, 2012, the staff finds it meets the acceptance criteria in SRP-LR Section 4.7.2.2 and is, therefore, acceptable. Additionally, the staff determines that the applicant provided an adequate summary

description of its actions to address steam generator tube wear, as required by 10 CFR 54.21(d).

4.7.9.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of loss of material caused by wear on the intended functions of the steam generator tube will be adequately managed by the Steam Generators Program for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.10 Mechanical Environmental Qualification

4.7.10.1 Summary of Technical Information in the Application

LRA Section 4.7.10 was added to the LRA by LRA Amendment 10, submitted by letter dated September 20, 2012. The section describes the applicant's TLAA for the evaluation of EQ of mechanical components for the period of extended operation. The LRA states that the Mechanical EQ Program establishes qualified lives for safety-related mechanical components located in harsh environments, in accordance with the requirements of 10 CFR Part 50, Appendix A, Criterion 4. The LRA states that as part of the qualification, replacement intervals were identified as required either on the basis of component aging under an IEEE 323-1974 qualification program or based on published material aging data. The LRA also states that the EQ of Electrical Components Program manages applicable component thermal, radiation, and cyclic aging effects for mechanical EQ components for the current operating license using methods for qualification for aging and accident conditions established by 10 CFR 50.49(f). The applicant took an exception to the LRA Appendix B, Section B3.2, "Environmental Qualification (EQ) of Electric Components" Program that expands the "scope of program" to include mechanical EQ components. The LRA further states that this ensures the effects of aging on the intended function(s) of equipment included under mechanical EQ will be adequately addressed for the period of extended operation. The applicant finally stated that mechanical components with qualification extending beyond 40 years are TLAAs and are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

LRA Section 4.4 states that re-analysis of an aging evaluation to extend the qualification of components (qualified life) is performed on a routine basis as part of the EQ of Electric Components Program. The applicant included under this program the important attributes of reanalysis including analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met).

The applicant dispositioned the TLAA for mechanical components, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of thermal, radiation, and cyclical aging on the intended functions will be adequately managed by the EQ of Electric Components Program for the period of extended operation.

4.7.10.2 Staff Evaluation

By letter dated September 20, 2012, as part of its response to RAI 4.4-1, the applicant amended its LRA to add LRA Section 4.7.10, "Mechanical Environmental Qualification." The staff's evaluation of the applicant's response to RAI 4.4-1 is documented in SER Section 4.4.2. The staff reviewed the applicant's TLAA for the EQ of mechanical components and the

corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with the review procedures in SRP-LR Sections 4.4.3.1.3 and 4.7.3.1.3, which state that an applicant must demonstrate the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The applicant is using its EQ of Electric Components Program to manage the effects of aging for mechanical EQ components.

The staff reviewed LRA Sections 4.7.10 and B3.2, plant basis documents, and interviewed plant personnel to verify whether the applicant provided adequate information to meet the requirement of 10 CFR 54.21(c)(1). For mechanical EQ components, the applicant dispositions its TLAA evaluation in accordance with 10 CFR 54.21(c)(1)(iii), that the aging effects of mechanical EQ components will be adequately managed by its EQ of Electric Components Program during the period of extended operation based on both electrical and mechanical components having the same materials, environments, and aging effects. Per the GALL Report, a plant EQ of Electric Equipment Program that implements the requirements of 10 CFR 50.49 is considered an acceptable AMP under license renewal 10 CFR 54.21(c)(1)(iii), with GALL Report AMP X.E1, "Environmental Qualification (EQ) of Electric Components," providing a means to meet the requirements of 10 CFR 54.21(c)(1)(iii). The staff reviewed the applicant's EQ of Electric Components Program to determine whether it will ensure that the mechanical components covered under this program will continue to perform their intended functions, consistent with the CLB, for the period of extended operation. LRA Section 4.7.10 for mechanical EQ is also consistent with the guidance provided in SRP-LR Section 4.4.1, which states that a TLAA for mechanical components should be performed under the provision of SRP-LR Section 4.7, "Other Plant-Specific Time-Limited Aging Analysis."

The staff's evaluation of the components qualification focused on how the EQ of Electric Equipment Program manages the aging effects to meet the requirements, in accordance with 10 CFR 50.49 and 10 CFR Part 50, Appendix A, Criterion 4, for mechanical EQ components. The applicant stated that as part of qualification, replacement intervals were identified for mechanical equipment. The applicant also stated that the qualifications of some mechanical equipment extends beyond 40 years and are considered TLAAs. Therefore, mechanical components qualified for 40 years need to be evaluated to determine the qualified life for the period of extended operation. The applicant also stated that design basis conditions will remain the same as the current license period and the design basis parameters for temperature, radiation and humidity do not require further evaluation for license renewal.

The EQ of Electric Components Program includes an exception to expand the scope to include aging management of mechanical EQ components. The staff conducted an audit of the information provided in LRA Sections 4.4 and B3.2 and the program basis documents. LRA Section B3.2 discusses the component reanalysis attributes, including analytical models, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions for the program. As described in SER Section 3.0.3.1.19, the staff found that the EQ of Electric Equipment Program with the expanded scope for mechanical EQ components exception, which the applicant claimed to be consistent with GALL Report AMP X.E1, is consistent with the GALL Report.

The applicant's mechanical EQ TLAA is implemented per the requirements of 10 CFR 54.21(c)(1)(iii) and therefore is consistent with SRP-LR Sections 4.7.3.1.3 and 4.4.3.1.3 and with the applicant's TLAA for EQ of Electric Components Program. The staff finds that the applicant's mechanical EQ TLAA, in conjunction with the applicant's EQ of Electric Components Program, will adequately manage the aging effects for mechanical EQ components for the

period of extended operation. The staff's review of the EQ of Electric Components Program is documented in SER Section 3.0.3.1.19.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of thermal, radiation, and cyclical aging on the intended functions of mechanical EQ components will be adequately managed for the period of extended operation. Additionally, the applicant's mechanical EQ TLAA meets the acceptance criteria in SRP-LR Section 4.7.2.1 because the applicant's EQ of Electric Equipment Program is capable of programmatically managing the qualified life of mechanical EQ components within the scope of the program for license renewal. The continued implementation of the EQ of Electric Equipment Program provides assurance that the aging effects will be managed and that components within the scope of the EQ of Electric Equipment Program, including mechanical EQ components, will continue to perform their intended functions for the period of extended operation.

4.7.10.3 FSAR Supplement

LRA Section A3.6.10, as incorporated by LRA Amendment 10, dated September 20, 2012, provides the FSAR supplement summarizing the mechanical EQ TLAA. The staff reviewed LRA Section A3.6.10, consistent with the review procedures in SRP-LR Section 4.7.3.2, which state that the FSAR supplement is reviewed to verify that the applicant has provided information to be included in the FSAR supplement that includes a summary description of the evaluation of each TLAA.

Based on its review of the FSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.7.2.2 and is, therefore, acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the mechanical EQ TLAA for the period of extended operation, as required by 10 CFR 54.21(d).

4.7.10.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of thermal, radiation, and cyclical aging on the intended functions of the mechanical components will be adequately managed by the mechanical EQ TLAA for the period of extended operation. The staff also concludes that the FSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.8 Conclusion

The staff reviewed the information in LRA Section 4, "Time-Limited Aging Analyses." On the basis of its review, the staff concludes that the applicant provided a sufficient list of TLAAs, as defined in 10 CFR 54.3, and that the applicant has demonstrated the following:

- The TLAAs will remain valid for the period of extended operation, as required by 10 CFR 54.21(c)(1)(i).
- The TLAAs have been projected to the end of the period of extended operation, as required by 10 CFR 54.21(c)(1)(ii).
- The effects of aging on intended functions will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(c)(1)(iii).

The staff also reviewed the FSAR supplement for the TLAAs and finds that the supplement contains descriptions of the TLAAs sufficient to satisfy the requirements of 10 CFR 54.21(d). In addition, the staff concludes, as required by 10 CFR 54.21(c)(2), that no plant-specific, TLAA-based exemptions are in effect.

With regard to these matters, the staff concludes that there is reasonable assurance that the activities authorized by the renewed licenses will continue to be conducted in accordance with the CLB. Additionally, any changes made to the CLB to comply with 10 CFR 54.29(a) are in accordance with the Atomic Energy Act of 1954, as amended, and NRC regulations.

SECTION 5

REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," the Advisory Committee on Reactor Safeguards (ACRS) reviewed the license renewal application (LRA) for Callaway Plant, Unit 1 (Callaway) in its meeting on May 22, 2014. The ACRS Subcommittee on Plant License Renewal will continue its detailed review of the LRA after this safety evaluation report (SER) is issued. Union Electric Company, doing business as Ameren Missouri and the staff of the United States (U.S.) Nuclear Regulatory Commission (NRC) (the staff) will meet with the ACRS full committee to discuss issues associated with the review of the LRA.

After the ACRS completes its review of the LRA and SER, the full committee will issue a report discussing the results of its review. An update to this SER will include the ACRS report and the staff's response to any issues and concerns reported.

SECTION 6

CONCLUSION

The staff of the United States (U.S.) Nuclear Regulatory Commission (NRC) (the staff) reviewed the license renewal application (LRA) for Callaway Plant, Unit 1, in accordance with NRC regulations and NUREG-1800, Revision 2, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” dated December 2010. Title 10 of the *Code of Federal Regulations* (10 CFR) 54.29, “Standards for Issuance of a Renewed License,” sets the standards used for issuing a renewed license.

On the basis of its review of the LRA, the staff determines that the requirements of 10 CFR 54.29(a) have been met.

The staff noted that any issues pertaining to 10 CFR Part 51, “Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions," Subpart A, “National Environmental Policy Act—Regulations Implementing Section 102(2),” will be documented in NUREG-1437, plant-specific supplement 51, “Generic Environmental Impact Statement for License Renewal of Nuclear Plants, Supplement 51, Regarding Callaway Plant, Unit 1.”

APPENDIX A

CALLAWAY PLANT UNIT 1 LICENSE RENEWAL COMMITMENTS

During the review of the Callaway Plant Unit 1 (Callaway) license renewal application (LRA) by the staff of the U.S. Nuclear Regulatory Commission (NRC or the staff), Union Electric Company, doing business as Ameren Missouri (the applicant), made commitments related to aging management programs (AMPs) to manage aging effects of structures and components. LRA Section A0, "Appendix A Introduction," states that Appendix A "[as revised by supplements and RAI responses] provides the information to be submitted in a Supplement to the Final Safety Analysis Report (FSAR) Update as required by 10 CFR 54.21(d) for the Callaway Plant License Renewal Application." It also states "…Section A4 contains summary descriptions of license renewal commitments. These summary descriptions […] and license renewal commitments will be incorporated in the Callaway Plant FSAR Update following issuance of the renewed operating license in accordance with 10 CFR 50.71(e)." The following table lists these commitments, as well as the implementation schedules and the sources for each commitment.

Item Number	Commitment	FSAR Supplement Section/ LRA Section	Implementation Schedule	Source
1	Procedures will be enhanced to apply the elements of corrective actions, confirmation process, and administrative controls of the Callaway Plant Quality Assurance Program to those nonsafety-related structures, systems, and components (SSCs) requiring aging management. (Completed LRA Amendment 23 dated April 26, 2013)	B1.3	Completed	Letter ULNRC-05963 dated February 28, 2013 Letter ULNRC-05979 dated April 26, 2013
2	Enhance the station operating experience review process and Corrective Action Program (CAP) to perform reviews of plant-specific and industry operating experience to confirm the effectiveness of the license renewal aging management programs (AMPs), to determine the need for AMPs to be enhanced, or indicate the need to develop a new AMP. In order to provide additional assurance that internal and external operating experience related to aging management continues to be used effectively in the AMPs, Callaway will enhance its operating experience program to: • Explicitly require the review of operating experience for age-related degradation. (Completed LRA Amendment 18 dated December 19, 2012) • Establish criteria to define age-related degradation. In general, the criteria will be used to identify aging that is considered excessive relative to design, previous inspection experience, and inspection intervals. (Completed LRA Amendment 18 dated December 19, 2012) • Establish coding for use in identification, trending and communications of age-related degradation. This coding will assist plant personnel in ensuring that, in addition to addressing the specific issue, the adequacy of existing aging management programs is assessed. This could lead to AMP revisions or the establishment of new AMPs, as appropriate. (Completed LRA Amendment 18 dated December 19, 2012) • Require communication of significant internal age-related degradation, associated with SSCs in the scope of license renewal, to the industry. Criteria will be established for determining when aging-related degradation is significant. (Completed LRA Amendment 18 dated December 19, 2012)	B1.4	Completed	Letter ULNRC-05939 dated December 19, 2012 Letter ULNRC-05957 dated February 14, 2013 Letter ULNRC-05979 dated April 26, 2013

Item Number	Commitment	FSAR Supplement Section/ LRA Section	Implementation Schedule	Source
	• Require review of external operating experience for information related to aging management, and evaluation of such information for potential improvements to Callaway aging management activities. License Renewal Interim Staff Guidance (LR-ISG) documents will be reviewed as part of this external operating experience information as they are issued on an ongoing basis, capturing new insights or addressing issues that emerge from license renewal reviews. (Completed LRA Amendment 21 dated February 14, 2013) • Provide training to those responsible for screening, evaluating and communicating operating experience items related to aging-related degradation. This training will be commensurate with their role in the process. (Completed LRA Amendment 23 dated April 26, 2013) • Explicitly require AMP activities, criteria, and evaluations integral to the elements of the AMPs be included in the operating experience evaluation. (Completed LRA Amendment 21 dated February 14, 2013)			
3	Enhance the Boric Acid Corrosion Program procedures to: include steel, copper alloy greater than 15% zinc, and aluminum as materials that are susceptible to boric acid corrosion. (Completed LRA Amendment 13 dated October 24, 2012) • Ensure that system engineers will observe for signs of boric acid residue when performing system walkdowns. (Completed LRA Amendment 13 dated October 24, 2012) • Specify that the corrective actions taken by the program will include a consideration to modify the present design or operating procedures to mitigate or prevent recurrence of aging effects caused by borated water leakage. Consideration will be given to modifications that (a) reduce the probability of primary coolant leaks at locations where they may cause corrosion damage and (b) entail the use of suitable corrosion resistant materials or the application of protective coatings or claddings. (Completed LRA Amendment 13 dated October 24, 2012)	B2.1.4	Completed	Letter ULNRC-05920 dated October 24, 2012 Letter ULNRC-05963 dated February 28, 2013

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4	Implement the PWR Vessel Internals Program as described in LRA Section B2.1.6. As part of the implementation activities address the following Applicant/Licensee Action Items (A/LAI) of NRC MRP-227-A Safety Evaluation dated December 16, 2011. (Completed LRA Amendment 28 dated December 20, 2013) Applicant/Licensee Action Item (A/LAI) #1 Each applicant or licensee is responsible for assessing its plant's design and operating history and demonstrating that the approved version of Materials Reliability Program (MRP)-227 is applicable to the facility. Each applicant or licensee shall refer, in particular, to the assumptions regarding plant design and operating history made in the failure modes, effects, and criticality analysis and functionality analyses for reactors of their design (i.e., Westinghouse, Combustion Engineering, or Babcock and Wilcox) which support MRP-227 and describe the process used for determining plant-specific differences in the design of their reactor vessel internals (RVI) components or plant operating conditions, which result in different component inspection categories. The applicant or licensee shall submit this evaluation for NRC review and approval as part of its application to implement the approved version of MRP-227. (Completed LRA Amendment 28 dated December 20, 2013)	B2.1.6	Completed	LRA Letter ULNRC-05950 dated January 24, 2013 Letter ULNRC-06050 dated October 17, 2013 Letter ULNRC-06057 dated December 20, 2013 Letter ULNRC-06080 dated February 14, 2014 Letter ULNRC-06106 dated March 28, 2014

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5	Enhance the Bolting Integrity Program procedures to: • Reference NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation of Failure in Nuclear Power Plants," and Electric Power Research Institute (EPRI) NP-5769 to meet the GALL Report recommendations. (Completed LRA Amendment 1 dated April 25, 2012) • Include bolting in the list of items to be inspected during walkdowns. (Completed LRA Amendment 15 dated November 8, 2012) • Include a visual inspection of a sample of submerged bolting heads in raw water and waste water environments every four refueling outages (6 years) when the pumps are dewatered. In addition, when submerged raw water and waste water pump casings are disassembled during maintenance activities, the bolting threads will be opportunistically inspected. A sample of submerged bolting on the fuel oil storage tank transfer pumps will be visually inspected every 10 years when the pumps are disassembled during maintenance activities. The sample for submerged bolting will be 20% of the population with a maximum of 25 for each environment. The inspection of submerged bolting will focus on the bounding or lead components most susceptible to aging due to time in service and severity of operating conditions.	B2.1.8	Portions completed are as shown. Remaining portions to be implemented as follows: Completed no later than 6 months prior to the period of extended operation. Inspections and testing to be completed no later than 6 months 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.	Letter ULNRC-05856 dated April 25, 2012 Letter ULNRC-05928 dated November 8, 2012 Letter ULNRC-05963 dated February 28, 2013 Letter ULNRC-06121 dated June 5, 2014
6	Enhance the Open-Cycle Cooling Water System Program procedures to: • Include polymeric material inspection requirements, parameters monitored, and acceptance criteria. Examination of polymeric materials by the Open-Cycle Cooling Water System Program will be consistent with examinations described in the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. • Include inspection and cleaning, if necessary, of the air-side of safety-related air-to-water heat exchangers cooled by the essential service water (ESW) system. • Prior to the period of extended operation, an inspection technique will be selected from available technologies to identify internal pipe wall degradation due to MIC for performance of a one-time inspection of a	B2.1.10	Completed no later than 6 months prior to the period of extended operation. Inspections and testing to be completed no later than 6 months 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.	Letter ULNRC-05892 dated August 21, 2012 Letter ULNRC-05963 dated February 28, 2013

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	buried carbon steel piping segment that is representative of other accessible carbon steel ESW piping segments. • Procedures will be enhanced to perform periodic visual inspections on all accessible internal surface coatings of the component cooling water heat exchangers, Class IE electrical equipment air conditioners, control room air conditioners, and essential service water self-cleaning strainers. Baseline inspections will be conducted in the 10-year period prior to the period of extended operation on the accessible internal surfaces coatings of the in-scope components. Coatings are inspected every 6 years on an alternating train basis based on no observed degradation or cracking and flaking that has been evaluated as acceptable; and the component is not subject to turbulent flow. Baseline inspections may be used to demonstrate that long-term coatings are or are not subject to turbulent flow conditions that could result in mechanical damage to the coating. Coatings with blisters, peeling, delaminations, or rusting that has been determined not to require remediation are inspected on a 4-year frequency. For peeling, delaminations, and blisters determined to not meet the acceptance criteria and that will not be repaired or replaced, physical testing is performed where physically possible (i.e., sufficient room to conduct testing). Testing consists of destructive or nondestructive adhesion testing using ASTM International Standards endorsed in RG 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Plants." Monitoring and trending of coatings is based on a review of the previous two inspections' results (including repairs) with the current inspection results. The training and qualification of individuals involved in coating inspections are conducted in accordance with ASTM International Standards endorsed in RG 1.54 including guidance from the staff associated with a particular standard. Coating acceptance criteria are as follows: • Indications of peeling and delamination are not acceptable and the coatings are repaired or replaced.			

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	• Blisters are evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff guidance associated with use of a particular standard. • Indications such as cracking, flaking, and rusting are to be evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff guidance associated with use of a particular standard. • Adhesion testing results meet or exceed the degree of adhesion recommended in engineering documents specific to the coating and substrate. Inspection results not meeting the acceptance criteria will be evaluated by a qualified coatings evaluator. Corrective actions will be determined using the Corrective Action Program.			
7	Enhance the Closed Treated Water Systems Program procedures to: • Include visual inspections of the surfaces of components with a closed treated water systems water environment. Representative samples of each combination of material and water treatment program will be visually inspected at least every 10 years or opportunistically when consistent with sample requirements. Sample locations will be selected based on the likelihood of corrosion and cracking. Inspections will be conducted and evaluated consistent with ASME Code inspections, industry standards, or a plant-specific inspection procedure by personnel qualified to detect aging. If adverse conditions are found, additional examinations will be performed. This periodic inspection will determine the extent of cracking, loss of material and fouling, and serves as a leading indicator of the condition of the interior of piping components otherwise inaccessible for visual inspection.	B2.1.11	Completed no later than 6 months prior to the period of extended operation. Inspections to be completed no later than 6 months 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.	Letter ULNRC-05886 dated August 6, 2012 Letter ULNRC-05963 dated February 28, 2013

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8	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, and loss of preload due to loose or missing bolts and nuts. • Include performance of periodic inspections as defined in the appropriate ASME B30 series standard for all cranes, hoists, and equipment handling systems within the scope of license renewal. For handling systems that are infrequently in service, such as those only used during refueling outages, periodic inspections may be deferred until just prior to use. • Require evaluation of loss of material due to wear or corrosion and loss of bolting preload per the appropriate ASME B30 series standard. • Require repairs to cranes, hoists, and equipment handling systems per the appropriate ASME B30 series standard.	B2.1.12	Completed no later than 6 months prior to the period of extended operation. Inspections to be completed no later than 6 months 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.	Letter ULNRC-05963 dated February 28, 2013
9	Enhance the Fire Protection Program procedures to: • Include visual inspections of the external surfaces of halon fire suppression system components for excessive loss of material due to corrosion. (Completed LRA Amendment 28 dated December 20, 2013) • Include trending of the performance of the halon system during testing. (Completed LRA Amendment 1 dated April 25, 2012)	B2.1.13	Completed	Letter ULNRC-05856 dated April 25, 2012 Letter ULNRC-06057 dated December 20, 2013
10	Recoat the internal surface of fire water storage tanks. Enhance the Fire Water System Program procedures to: • Perform internal inspections on accessible exposed portions of fire water piping during plant maintenance activities. When visual inspections are used to detect loss of material, the inspection technique is capable of detecting surface irregularities that could indicate wall loss to below nominal pipe wall thickness due to corrosion and corrosion product deposition. Where such irregularities are detected, followup volumetric wall thickness examinations are performed. • Replace sprinkler heads prior to 50 years in service, or have a recognized testing	B2.1.14	Implementation is started 5 years before the period of extended operation. Recoat the internal surface of the fire water storage tanks and inspections of wetted segments that cannot be drained or that allow water to collect to be completed no later than 6 months prior to the period of extended operation or the end of the last refueling outage prior to the period of extended operation,	Letter ULNRC-05923 dated October 31,2012 Letter ULNRC-05963 dated February 28, 2013 Letter ULNRC-06057 dated December 20, 2013

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	laboratory field-service test a representative sample in accordance with National Fire Protection Association (NFPA) 25 and test additional samples every 10 years thereafter to ensure signs of aging are detected in a timely manner. • Review and evaluate trends in flow parameters recorded during the NFPA 25 fire water flow tests. • Perform annual hydrant flow testing in accordance with NFPA 25. • Perform annual hydrostatic testing of fire brigade hose. • Enhance the Fire Water System program to include nonintrusive pipe wall thickness examinations. Wall thickness measurements will be performed on fire water piping every 3 years. Each 3-year sample will include at least three locations for a total of 100 feet of aboveground fire water piping and will be selected based on system susceptibility to corrosion or fouling and evidence of performance degradation during system flow testing or periodic flushes. Pipe wall thickness examinations and internal inspections will be performed commencing after 2014 and throughout the period of extended operation. • Perform augmented tests and inspections of water-based fire protection system components that have been wetted but are normally dry. The augmented tests and inspections are conducted as follows on piping segments that cannot be drained or that allow water to collect: • In each 5-year interval, beginning 5 years prior to the period of extended operation, either conduct a flow test or flush sufficient to detect potential flow blockage, or conduct a visual inspection of 100% of the internal surface of piping segments that cannot be drained or allow water to collect. • A 100% baseline inspection will be performed prior to the period of extended operation. In each 5-year interval of the period of extended operation, 20% of the length of piping		whichever occurs later. The program's remaining inspections begin during the period of extended operation.	Letter ULNRC-05897 dated August 16, 2012 Letter ULNRC-06117 dated April 23, 2014 Letter ULNRC-06118 dated May 6, 2014

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	segments that cannot be drained or that allow water to collect is subject to volumetric wall thickness inspections. Measurement points will be obtained to the extent that each potential degraded condition can be identified (e.g., general corrosion, MIC). The 20% of piping that is inspected in each 5-year interval will be in different locations than previously inspected piping. If the results of a 100% internal visual inspection are acceptable, and the segment is not subsequently wetted, no further augmented tests or inspections will be performed. • Require the inspection of the interior of the fire water storage tanks to include checking for evidence of voids beneath the floor. • Change the frequency of trip testing each deluge valve from every 3 years to every refueling outage. • Change the frequency of tests of spray/sprinkler nozzle discharge patterns from every 3 years to every refueling outage. • Perform the following additional inspections if pitting, corrosion, or coating failure is found during the inspection of the fire water storage tanks: (1) tank coatings are evaluated using an adhesion test consistent with ASTM D 3359, Standard Test Methods for Measuring Adhesion by Tape Test; (2) dry film thickness measurements are taken at random locations to determine the overall coating thickness; (3) nondestructive ultrasonic readings are taken to evaluate the wall thickness where there is evidence of pitting or corrosion; (4) interior surfaces are spot wet-sponge tested to detect pinholes, cracks, or other compromises in the coating; (5) tank bottoms are tested for metal loss on the underside by use of ultrasonic testing where there is evidence of pitting or corrosion; (6) bottom seams are vacuum-box tested in accordance with NFPA 22, Standard for Water Tanks for Private Fire Protection. • Require the removal of foreign material if its presence is found during pipe			

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	inspections to obstruct pipe or sprinklers. In addition, the source of the material is determined and corrected.
	• Perform main drain tests consistent with NFPA 25, Section 13.2.5, of a representative sample of 20% of the main drains within the scope of license renewal annually in order to check for potential flow blockage in system risers. During annual testing, one of the tests is performed in a radiologically controlled area.
	• Inspect wet pipe suppression systems every 5 years consistent with NFPA 25, Section 14.2. For buildings containing multiple systems, half are inspected in the first 5-year interval and the remaining half inspected in the next 5-year interval. If sufficient foreign material is found in any system in a building, then all systems in the building will be inspected. The NFPA 25, Section 14.2, inspection of dry pipe preaction systems will be performed following actuation, prior to return to service. If sufficient foreign material is found to obstruct pipe or sprinklers, then an obstruction investigation is conducted per NFPA 25 Annex D. If the visual inspection detects surface irregularities that could indicate wall loss below nominal pipe wall thickness, then followup volumetric examinations will be performed.
	• Revise the implementation procedure and calculation for changing test and inspection frequencies associated with the NFPA 805 license amendment (Amendment 206) to note the following restrictions when changing license renewal Fire Water System program and Fire Protection program test and inspection frequencies.
	  • EPRI Report 1006756, Fire Protection Equipment Surveillance Optimization and Maintenance Guide will be used to adjust test and inspection frequencies.
	  • Data to be used in analyzing the potential for modifying test and inspection frequencies would not be obtained any earlier than 5 years prior to the period of extended operation.			

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	• A minimum sample size consistent with EPRI Report 1006756 Section 11.2 will be used to modify test and inspection frequencies. • EPRI Report 1006756 would not be used to modify fire water storage tank inspections/tests, underground flow tests, and inspections of normally dry but periodically wetted piping that will not drain due to its configuration.			
11	Implement the Aboveground Metallic Tanks Program as described in LRA Section B2.1.15.	B2.1.15	Implementation started within the 5-year period prior to the period of extended operation. Completed no later than 6 months prior to the period of extended operation. Inspections to be completed no later than 6 months 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.	Letter ULNRC-05923 dated October 31, 2012 Letter ULNRC-05963 dated February 28, 2013
12	Remove the blisters in the coating, inspect the base metal for aging, and repair the coating in the train A emergency diesel generator fuel oil storage tank. Enhance the Fuel Oil Chemistry Program procedures to: • Include periodic draining of the water from the bottom of the emergency fuel oil system day tanks, diesel fire pump fuel oil day tanks, and security diesel generator fuel oil day tank. • Include the addition of biocide to the diesel fire pump fuel oil day tank and security diesel generator fuel oil day tank if periodic testing indicates biological activity or evidence of corrosion. • Include draining, cleaning, and inspection of the emergency fuel oil system day tanks within the 10-year period prior to the period of extended operation and at least once every 10 years after entering the period of extended operation.	B2.1.16	Completed no later than 6 months prior to the period of extended operation. Inspections and referenced coating repairs to be completed no later than 6 months 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.	Letter ULNRC-05923 dated October 31, 2012 Letter ULNRC-05950 dated January 24, 2013 Letter ULNRC-05963 dated February 28, 2013 Letter ULNRC-06117 dated April 23, 2014

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	• Include a determination of water and sediment in the periodic sampling of the emergency fuel oil system day tanks and security diesel generator fuel oil day tank. • Include a determination of particulate concentrations in the periodic sampling of the emergency fuel oil system day tanks, diesel fire pump fuel oil day tanks, and security diesel generator fuel oil day tank. • Include a determination of microbial activity concentrations in the periodic sampling of the emergency fuel oil system storage tanks, emergency fuel oil system day tanks, diesel fire pump fuel oil day tanks, and security diesel generator fuel oil day tank. • Include new fuel oil receipt sampling for water and sediment prior to introduction into the security diesel generator fuel oil day tank and diesel fire pump fuel oil day tank. • Perform a volumetric examination of the emergency fuel oil system storage tanks and day tanks after evidence of tank degradation is observed during the visual inspection within the 10-year period prior to the period of extended operation and at least once every 10 years after entering the period of extended operation. • Perform a volumetric examination on the external surface of the diesel fire pump fuel oil day tanks and security diesel generator fuel oil day tank within the 10-year period prior to the period of extended operation and at least once every 10 years after entering the period of extended operation. • Include at least quarterly trending for water, biological activity, and particulate concentrations on the emergency fuel oil system day tanks, diesel fire pump fuel oil day tanks, and security diesel generator fuel oil day tank. • Include immediate removal of accumulated water when discovered in the emergency fuel oil system day tank, diesel fire pump fuel oil day tank, and security diesel generator fuel oil day tank. • Perform periodic visual inspections on all accessible internal surface coatings of the emergency fuel oil storage tanks and day tanks. Baseline inspections will be conducted in the 10-year period prior to the period of extended operation on the			

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	accessible internal surfaces coatings of the in-scope components. Coatings are inspected every 6 years on an alternating train basis based on no observed degradation or cracking and flaking that has been evaluated as acceptable. Coatings with blisters, peeling, delaminations, or rusting that has been determined not to require remediation are inspected on a 4-year frequency. For peeling, delaminations and blisters determined to not meet the acceptance criteria and that will not be repaired or replaced, physical testing is performed where physically possible (i.e., sufficient room to conduct testing). Testing consists of destructive or nondestructive adhesion testing using ASTM International Standards endorsed in RG 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Plants." Monitoring and trending of coatings is based on a review of the previous two inspections' results (including repairs) with the current inspection results. The training and qualification of individuals involved in coating inspections are conducted in accordance with ASTM International Standards endorsed in RG 1.54 including guidance from the staff associated with a particular standard. Coating acceptance criteria are as follows: • Indications of peeling and delamination are not acceptable and the coatings are repaired or replaced. • Blisters are evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff guidance associated with use of a particular standard. • Indications such as cracking, flaking, and rusting are to be evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including staff guidance associated with use of a particular standard. • Adhesion testing results meet or exceed the degree of adhesion recommended in engineering documents specific to the coating and substrate.			

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	Inspection results not meeting the acceptance criteria will be evaluated by a qualified coatings evaluator. Corrective actions will be determined using the Corrective Action Program.			
13	Enhance the Reactor Vessel Surveillance Program to: • Determine the vessel fluence by ex-vessel dosimetry, following withdrawal of the final capsule. (Completed LRA Amendment 28 dated December 20, 2013) • Require that pulled and tested surveillance capsules are placed in storage for future reconstitution or reinsertion unless given NRC approval to discard. (Completed LRA Amendment 28 dated December 20, 2013) • Specifically require the design change process to evaluate the impact of plant operation changes on reactor vessel embrittlement. (Completed LRA Amendment 14 dated October 31, 2012)	B2.1.17 4.2	Completed	Letter ULNRC-05923 dated October 31, 2012 Letter ULNRC-06057 dated December 20, 2013
14	Implement the One-Time Inspection Program as described in LRA Section B2.1.18.	B2.1.18	Implementation started within the 10-year period prior to the period of extended operation. Completed no later than 6 months prior to the period of extended operation. Inspections to be completed no later than 6 months 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.	Letter ULNRC-05963 dated February 28, 2013

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15	Implement the Selective Leaching Program as described in LRA Section B2.1.19.	B2.1.19	Implementation started within the 5-year period prior to the period of extended operation. Completed no later than 6 months prior to the period of extended operation. Inspections to be completed no later than 6 months 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.	Letter ULNRC-05963 dated February 28, 2013
16	Implement the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program as described in LRA Section B2.1.20.	B2.1.20	Implementation started within the 6-year period prior to the period of extended operation. Completed no later than 6 months prior to the period of extended operation. Inspections to be completed no later than 6 months 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.	Letter ULNRC-05963 dated February 28, 2013
17	Implement the External Surfaces Monitoring of Mechanical Components Program as described in LRA Section B2.1.21.	B2.1.21	Implemented no later than 6 months prior to the period of extended operation and inspections to begin during the period of extended operation.	Letter ULNRC-06057 dated December 20, 2013

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18	Implement the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program as described in LRA Section B2.1.23.	B2.1.23	Completed no later than 6 months prior to the period of extended operation. Inspections to be completed no later than 6 months 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.	Letter ULNRC-05963 dated February 28, 2013
19	Enhance the Lubricating Oil Program procedures to: • Indicate that lubricating oil contaminants are maintained within acceptable limits, thereby preserving an environment that is not conducive to loss of material or reduction of heat transfer. (Completed LRA Amendment 34 dated April 23, 2014) • State the testing standards for water content and particle count. (Completed LRA Amendment 34 dated April 23, 2014) • State that phase separated water in any amount is not acceptable. (Completed LRA Amendment 34 dated April 23, 2014)	B2.1.24	Completed	Letter ULNRC-06117 dated April 23, 2014
20	Implement the Buried and Underground Piping and Tanks Program as described in LRA Section B2.1.25.	B2.1.25	Implementation to be started within the 10-year period prior to the period of extended operation. Completed no later than 6 months prior to the period of extended operation. Inspections to be completed no later than 6 months 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.	Letter ULNRC-05963 dated February 28, 2013

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21	Enhance the ASME Section XI, Subsection IWE Program to: • Specify that whenever replacement of bolting is required, bolting material, installation torque or tension, and use of lubricants and sealants are in accordance with the guidelines of EPRI NP 5769, EPRI TR 104213, and the additional recommendations of NUREG-1339. • Perform additional surface examinations of stainless steel penetration sleeves, dissimilar metal welds, bellows, and steel components that are subject to cyclic loading for cracking, unless Appendix J testing is adequate to identify cracking.	B2.1.26	Completed no later than 6 months prior to the period of extended operation. Inspections and testing to be completed no later than 6 months 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.	Letter ULNRC-05963 dated February 28, 2013
22	Enhance the ASME Section XI, Subsection IWF Program procedures to: • Specify that whenever replacement of bolting is required, bolting material, installation torque or tension, and use of lubricants and sealants are in accordance with the applicable EPRI guidelines, ASTM standards, American Institute of Steel Construction specifications, and NUREG recommendations to prevent or mitigate degradation and failure of safety-related bolting due to stress corrosion cracking (SCC). Specifically, if ASTM A325, ASTM F1852, and/or ASTM A490 bolts are used, the preventive actions as discussed in Section 2 of the Research Council for Structural Connections, *Specification for Structural Joints Using ASTM A325 or A490 Bolts*, will be followed.	B2.1.28	Completed no later than 6 months prior to the period of extended operation.	Letter ULNRC-05891 dated August 9, 2012 Letter ULNRC-05963 dated February 28, 2013
23	Enhance the Structures Monitoring Program procedures to: • Include the main access facility, the nitrogen storage tank foundation and pipe trench, and the reinforced concrete structures under the turbine building and in the yard that provide a return flowpath for the circulating water system in the scope of the Structures Monitoring Program. • Specify that whenever replacement of bolting is required, bolting material, installation torque or tension, and use of lubricants and sealants are in accordance with the guidelines of EPRI NP-5769, EPRI NP-5067, EPRI TR-104213, and the additional recommendations of NUREG-1339. • Specify the preventive actions for storage, lubricants, and SCC potential discussed in	B2.1.31	Completed no later than 6 months prior to the period of extended operation with the exception of item indicated by *, which will be completed by December 31, 2017, and item indicated by #, for which initial inspections were completed by December 31, 2012, and any corrective actions resulting from initial inspections will be completed no later than December 31, 2017.	Letter ULNRC-05891 dated August 9, 2012 Letter ULNRC-05915 dated October 11, 2012 Letter ULNRC-05950 dated January 24, 2013 Letter ULNRC-05963 dated February 28, 2013

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	Section 2 of the Research Council for Structural Connections publication, *Specification for Structural Joints Using ASTM A325 or A490 Bolts*, for ASTM A325, ASTM F1852, and/or ASTM A490 structural bolts. • Specify inspections of penetrations, transmission towers, electrical conduits, raceways, cable trays, electrical cabinets or enclosures, and associated anchorages, and complete a baseline inspection of these components.* • Specify that groundwater is monitored for pH, chlorides, and sulfates, and every 5 years at least two samples are tested and the results are evaluated by engineering to assess the impact, if any, on below grade structures. • Specify inspector qualifications in accordance with American Concrete Institute (ACI) 349.3R-96. • Quantify acceptance criteria and critical parameters for monitoring degradation, and to provide guidance for identifying unacceptable conditions requiring further technical evaluation or corrective action in accordance with the three-tier quantitative evaluation criteria recommended in ACI 349.3R. • Incorporate applicable industry codes, standards and guidelines for acceptance criteria. • Specify that degradation associated with seismic isolation gaps, obstructions of these gaps, or questionable material in these gaps, will be evaluated by an engineer familiar with the seismic design of the plant, and the evaluation will consider the seismic isolation function in determining what corrective actions may be required.#		Inspections and testing to be completed no later than 6 months 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.	Letter ULNRC-06118 dated May 6, 2014

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24	Enhance the Protective Coating Monitoring and Maintenance Program procedures to: • Specify parameters monitored or inspected to include any visible defects, such as blistering, cracking, flaking, peeling, rusting, and physical damage. • Specify inspection frequencies, personnel qualifications, inspection plans, inspection methods, and inspection equipment that meet the requirements of ASTM D 5163-08. • Specify 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 or as postponed to future outages, but under surveillance in the interim period. • Specify characterization, documentation, and testing consistent with ASTM D 5163-08 Sections 10.2–10.4 and to specify an evaluation of the inspection reports by the responsible coating evaluation specialist who prepares a summary of findings and recommendations for future surveillance or repair. • Specify that the inspection reports prioritize repair areas as either needing repair during the same outage or as postponed to future outages, but under surveillance in the interim period.	B2.1.33	Completed no later than 6 months prior to the period of extended operation. Inspections to be completed no later than 6 months 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.	Letter ULNRC-05963 dated February 28, 2013
25	Enhance the Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program procedures to: • Include all accessible in-scope cable in an adverse localized environment. • Ensure there are no unacceptable visual indications of surface anomalies. All unacceptable visual indications of cable jacket and connection insulation surface anomalies will be subject to an engineering evaluation.	B2.1.34	Completed no later than 6 months prior to the period of extended operation. Inspections to be completed no later than 6 months 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.	Letter ULNRC-05963 dated February 28, 2013

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26	Enhance the Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program procedures to: • Identify the scope of cables requiring aging management. • Require engineering review of surveillance results every 10 years. • Initiate corrective actions when surveillance results do not meet acceptance criteria, and to require an engineering evaluation be performed. When an unacceptable condition or situation is identified, a determination is also made as to whether the review of surveillance results or the cable testing frequency needs to be increased.	B2.1.35	Completed no later than 6 months prior to the period of extended operation. Inspections and testing to be completed no later than 6 months 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.	Letter ULNRC-05856 dated April 25, 2012 Letter ULNRC-05963 dated February 28, 2013

Item Number	Commitment	FSAR Supplement Section/ LRA Section	Implementation Schedule	Source
27	Enhance the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program procedures to: • Identify the power cables (greater than or equal to 400 volts), manholes, pits, and duct banks that are within the scope of the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. • Include periodic inspection of manholes, pits, and duct banks, to confirm cables are not submerged or immersed in water, cables/splices and cable support structures are intact, and dewatering/drainage systems (i.e., sump pumps) and associated alarms operate properly. • Identify that inspections will be performed at least annually based on water accumulation over time and after event-driven occurrences (e.g., heavy rain or flooding). In addition, operation of dewatering devices will be inspected and operation verified prior to any known or predicted heavy rain or flooding events. • Ensure in-scope power cables are tested at least once every 6 years and adjusted based on test results and operating experience. • Compare test results to previous test results to evaluate for additional information on the rate of cable degradation. • Confirm cables are not submerged or immersed in water, cables, splices, and cable support structures are intact, and dewatering/drainage systems (i.e., sump pumps) and associated alarms operate properly. Acceptance criteria for cable testing will be defined prior to each test. • Require an engineering evaluation when the test or inspection acceptance criteria are not met.	B2.1.36	Completed no later than 6 months prior to the period of extended operation. Inspections and testing to be completed no later than 6 months 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.	Letter ULNRC-05856 dated April 25, 2012 Letter ULNRC-05891 dated August 9, 2012 Letter ULNRC-05963 dated February 28, 2013

Item Number	Commitment	FSAR Supplement Section/ LRA Section	Implementation Schedule	Source
28	Implement the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program as described in LRA Section B2.1.37.	B2.1.37	Completed no later than 6 months prior to the period of extended operation. Inspections to be completed no later than 6 months 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.	Letter ULNRC-05963 dated February 28, 2013
29	Implement the Monitoring of Neutron-Absorbing Materials Other than Boraflex Program as described in LRA Section B2.1.38.	B2.1.38	Completed no later than 6 months prior to the period of extended operation. Inspections to be completed no later than 6 months 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.	Letter ULNRC-05963 dated February 28, 2013
30	Implement the Metal Enclosed Bus Program as described in LRA Section B2.1.39.	B2.1.39	Completed no later than 6 months prior to the period of extended operation. Inspections to be completed no later than 6 months 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.	Letter ULNRC-05963 dated February 28, 2013
31	Enhance the Fatigue Monitoring Program procedures to: • Include fatigue usage calculations that consider the effects of the reactor water environment for a set of sample reactor coolant pressure boundary locations and reactor vessel internals locations with fatigue usage calculations. The reactor coolant pressure boundary set includes the NUREG/CR-6260 sample locations for a newer-vintage Westinghouse Plant and	4.3.2.1 4.3.2.2 4.3.4 B3.1	Completed no later than 6 months prior to the period of extended operation.	Letter ULNRC-05874 dated June 5, 2012 Letter ULNRC-05963 dated February 28, 2013

Item Number	Commitment	FSAR Supplement Section/ LRA Section	Implementation Schedule	Source
	plant-specific bounding environmentally assisted fatigue (EAF) locations. • Ensure the scope includes the fatigue crack growth analyses, which support the leak-before-break analyses, ASME Code Section XI evaluations, and the high-energy line break (HELB) selection criterion remain valid by counting the transients used in the analyses. • Require the review of the temperature and pressure transient data from the operator logs and plant instrumentation to ensure actual transient severity is bounded by the design and to include environmental effects where applicable. If a transient occurs which exceeds the design transient definition the event is documented in the CAP and corrective actions are taken. • Include additional transients that contribute significantly to fatigue usage. These additional transients were identified by evaluation of ASME Code Section III fatigue and fatigue crack growth analyses. • Include additional locations which receive more detailed monitoring. These locations were identified by evaluation of ASME Section III fatigue analyses and the locations evaluated for effects of the reactor coolant environment. In addition, reactor vessel internals locations with fatigue usage calculations will be evaluated for the effects of the reactor water environment. The monitoring methods will be benchmarked consistent with the NRC Regulatory Issue Summary (RIS) 2008-30. • Project the transient count and fatigue accumulation of monitored components into the future. • Include additional cycle count and fatigue usage action limits, which permit completion of corrective actions if the design limits are expected to be exceeded within the next three fuel cycles. The fatigue results associated with the NUREG/CR-6260 sample locations for a newer-vintage Westinghouse plant and plant-specific bounding EAF locations will account for environmental effects on fatigue. The cycle count action limits for the hot leg surge nozzle will incorporate the 60-year cycle projections used in the hot leg surge nozzle EAF analysis.			Letter ULNRC-06050 dated October 17, 2013 Letter ULNRC-05979 dated April 26, 2013 Letter ULNRC-05860 dated May 3, 2012

Item Number	Commitment	FSAR Supplement Section/ LRA Section	Implementation Schedule	Source
	• Include appropriate corrective actions to be invoked if a component approaches a cycle count or CUF action limit or if an experienced transient exceeds the design transient definition. If an action limit is reached, corrective actions include fatigue reanalysis, repair, or replacement. When a cycle counting action limit is reached, action will be taken to ensure that the analytical bases of the HELB locations are maintained. 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. • Limit the number of the most severe RCP component cooling water transient, elevated CCW inlet temperature transients, to 75% of its design value (i.e., limited to 150) in order to accommodate the seasonal temperature change transient in the RCP thermal barrier flange fatigue analysis. (Moved here from Commitment No. 38 by LRA Amendment 23) • Include non-NUREG/CR-6260 locations with a U_{en} greater than 1.0 for further evaluation using the same methods as those used for NUREG/CR-6260 locations to remove conservatisms from the preliminary U_{en}. The results of these final analyses will be incorporated into the Fatigue Monitoring Program by either counting the transients assumed or incorporate the stress intensities into a CBF ability of the program. As an alternative, the Fatigue Monitoring Program will implement SBFs of certain locations in order to ensure the component does not exceed a U_{en} of 1.0. Any use of SBF will be implemented consistent with RIS 2008-30. • The sentinel location analysis, when refined, will be revisited to confirm bounding Reactor Coolant Pressure Boundary Environmentally Assisted Fatigue susceptible sentinel locations are updated appropriately and remain bounded consistent with the refined analysis.			

Item Number	Commitment	FSAR Supplement Section/ LRA Section	Implementation Schedule	Source
32	Enhance the Concrete Containment Tendon Prestress Program specification to: • Include random samples for the 40-, 45-, 50-, and 55-year surveillances. • Extend the predicted lower limit (PLL) lines for the vertical and hoop tendon groups to 60 years. • Specifically require the final report for each surveillance interval to plot the measured results against time and to include the PLL, Minimum Required Value, and trend lines. • Require a regression analysis consistent with the requirements of NRC Information Notice 99-10 Revision 1, Attachment 3.	B3.3 4.5	Completed no later than 6 months prior to the period of extended operation.	Letter ULNRC-05963 dated February 28, 2013
33	As additional industry and plant-specific applicable operating experience becomes available, it will be evaluated and incorporated into each new program.	B2.1.15 B2.1.18 B2.1.19 B2.1.20 B2.1.21 B2.1.23 B2.1.25 B2.1.37 B2.1.38 B2.1.39	Completed consistent with implementation schedule noted with each referenced AMP.	Letter ULNRC-05963 dated February 28, 2013 Letter ULNRC-06057 dated December 20, 2013

Item Number	Commitment	FSAR Supplement Section/ LRA Section	Implementation Schedule	Source
34	Ameren Missouri replacement steam generator divider plate assemblies are fabricated of Alloy 690. The divider plate to primary head and tubesheet junctions are welded with Alloy 152 weld materials. The tubesheet cladding is Alloy 182 and the primary head cladding is stainless steel. There is a concern regarding potential failure at the divider plate welds to primary head and tubesheet cladding and Ameren Missouri commits to perform one of the following three resolution options: Option 1: Inspection Perform a one-time inspection of each steam generator to assess the condition of the divider plate welds. The examination technique(s) will be capable of detecting primary water stress-corrosion cracking (PWSCC) in the divider plate assemblies and the associated welds. OR Option 2: Analysis Perform an analytical evaluation of the steam generator divider plate welds in order to establish a technical basis which concludes that the steam generator RCS pressure boundary is adequately maintained with the presence of steam generator divider plate weld cracking. The analytical evaluation will be submitted to the NRC for review and approval. OR Option 3: Industry/NRC Studies If results of industry and NRC studies and operating experience document that potential failure of the steam generator RCS pressure boundary due to PWSCC cracking of steam generator divider plate welds is not a credible concern, this commitment will be revised to reflect that conclusion.	Section 3.1.2.2.11.1 Table 3.1.2-4	Option 1 completed between fall 2025 and fall 2029 when the replacement steam generators are in service for more than 20 years. Option 2 or Option 3 available for NRC review in the fall 2023.	Letter ULNRC-05920 dated October 24, 2012 Letter ULNRC-06057 dated December 20, 2013 Letter ULNRC-06080 dated February 14, 2014

Item Number	Commitment	FSAR Supplement Section/ LRA Section	Implementation Schedule	Source
35	The material of steam generator tubesheet cladding is Alloy 182. The tubes are made of Alloy 690 and are secured to the tubesheet by means of tube-to-tubesheet leaktight weld and tube expansion. There is a concern regarding potential failure of primary-to-secondary pressure boundary due to PWSCC cracking of tube-to-tubesheet welds. Ameren Missouri commits to perform one of the following two resolution options: Option 1: Inspection Perform a one-time inspection of a representative number of tube-to-tubesheet welds in each steam generator to determine if PWSCC cracking is present. The examination technique(s) will be capable of detecting PWSCC in the tube-to-tubesheet welds. If weld cracking is identified, the condition will be resolved through repair or engineering evaluation to justify continued service, as appropriate, and a periodic monitoring program will be established to perform routine tube-to-tubesheet weld inspections for the remaining life of the steam generators. OR Option 2: Analysis Perform an analytical evaluation of the steam generator tube-to-tubesheet welds either determining that the welds are not susceptible to PWSCC or redefining the reactor coolant pressure boundary of the tubes, where the steam generator tube-to-tubesheet welds are not required to perform a reactor coolant pressure boundary function. The redefinition of the reactor coolant pressure boundary will be submitted as part of a license amendment request requiring approval from the NRC. The evaluation for determination that the welds are not susceptible to PWSCC and do not require inspection will be submitted to the NRC for review.	Section 3.1.2.2.11.2 Table 3.1.2-4	Option 1 completed between fall 2025 and fall 2029 when the replacement steam generators are in service for more than 20 years. Option 2 available for NRC review in the fall 2023.	Letter ULNRC-05920 dated October 24, 2012 Letter ULNRC-06057 dated December 20, 2013 Letter ULNRC-06080 dated February 14, 2014

Item Number	Commitment	FSAR Supplement Section/ LRA Section	Implementation Schedule	Source
36	Implement stress-based fatigue (SBF) or cycle-based fatigue (CBF) consistent with RIS 2008-30 to monitor the CUF of the limiting location out of the pressurizer lower head, surge nozzle, and heater penetrations to accommodate the insurge-outsurge transient. (Closed. LRA Amendment 11, dated October 11, 2012. The re-evaluation of insurge-outsurge analysis demonstrated that this type of detailed monitoring was not necessary.)	4.3.1 4.3.2.2 B3.1	Closed	Letter ULNRC-05915 dated October 11, 2012 Letter ULNRC-05963 dated February 28, 2013
37	Complete an evaluation to determine if there are any additional plant-specific bounding EAF locations. The supporting environmental factors, F(en), calculations will be performed with NUREG/CR-6909 or NUREG/CR-6583 for carbon and low-alloy steels, NUREG/CR-6909 or NUREG/CR-5704 for austenitic stainless steels, and NUREG/CR-6909 for nickel alloys. (Completed Amendment 2 dated May 3, 2012) In order to determine if the pressurizer contains a limiting EAF location, the fatigue analyses will be revised to incorporate the effect of insurge-outsurge transients on the pressurizer lower head, surge nozzle, and heater well nozzles at plant-specific conditions. (Completed Amendment 2 dated May 3, 2012) The pressurizer contains a limiting EAF location. The fatigue analyses will be revised to incorporate the effect of insurge-outsurge transients in the pressurizer lower head. (Completed LRA Amendment 11 dated October 11, 2012)	4.3.2.2 4.3.4	Completed	Letter ULNRC-05860 dated May 3, 2012 Letter ULNRC-05915 dated October 11, 2012 Letter ULNRC-05979 dated April 26, 2013
38	The number of the most severe RCP component cooling water (CCW) transient, elevated CCW inlet temperature transients, will be limited to 75% of its design value (i.e., limited to 150) to accommodate the seasonal temperature change transient in the RCP thermal barrier flange fatigue analysis. (Moved to Item #31 to be managed by the Fatigue Monitoring program – LRA Amendment 23 dated April 26, 2013)	See Commitment No. 31	Implemented as part of Commitment No. 31: Completed no later than 6 months prior to the period of extended operation.	Letter ULNRC-05979 dated April 26, 2013

Item Number	Commitment	FSAR Supplement Section/ LRA Section	Implementation Schedule	Source
39	NFPA 805 and LRA gap analysis: A gap analysis of LRA Tables 2.3.3-20 and 3.3.2-20 will be provided to identify differences between the existing and NFPA 805 post-transition changes. The results and the impacts of these gaps on the fire protection program described in LRA Tables 2.3.3-20 and 3.3.2-20 will be summarized, as the basis for transitioning to the NFPA 805 nuclear safety capabilities. The summary will also list the fire protection systems and components including structural fire barriers (e.g., fire walls and slabs, fire doors, fire barrier penetration seals, fire dampers, fire barrier coatings and wraps, equipment and personnel hatchways and plugs, metal siding) that will be added or removed based on the NFPA 805 transition in the scope of license renewal in accordance with 10 CFR 54.4(a) and whether they are subject to an AMR in accordance with 10 CFR 54.21(a)(1). (Completed Amendment 31 dated February 14, 2014)	B2.1.13 B2.1.14	Completed	Letter ULNRC-05877 dated July 2, 2012 Letter ULNRC-05946 dated January 10, 2013 Letter ULNRC-05971 dated March 20, 2013 Letter ULNRC-06080 dated February 14, 2014 Letter ULNRC-06114 dated April 15, 2014
40	Enhance the ASME Section XI, Subsection IWL Program to specify that acceptability of concrete surfaces is based on the evaluation criteria provided in ACI-349.3R.	B2.1.27	Completed no later than 6 months prior to the period of extended operation. Inspections to be completed no later than 6 months 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.	Letter ULNRC-05891 dated August 9, 2012 Letter ULNRC-05963 dated February 28, 2013
41	To allow for monitoring of the condition of the threads on the RPV stud and flange hole threads, Ameren Missouri commits to remove RPV stud #18 through nondestructive or destructive means. If RPV stud hole repair is required following removal of RPV stud #18, the repair plan will include inspecting the RPV stud hole prior to the repair to assess the as-found condition and an inspection after the repair is complete to assess the results of the repair.	B2.1.3	Implemented as part of proposed License Condition No. 3: Completed no later than 6 months prior to the period of extended operation or the refueling outage prior to the period of extended operation, whichever occurs later.	Letter ULNRC-06032 dated August 29, 2013 Letter ULNRC-06057 dated December 20, 2013

Item Number	Commitment	FSAR Supplement Section/ LRA Section	Implementation Schedule	Source
42	It is noted that Ameren Missouri experienced problems with the reactor vessel head closure studs and stud holes early in plant life (1986-1992) and that multiple RPV stud holes required ASME Section XI repairs to remove damaged threads. To supplement the monitoring that is accomplished through regular volumetric inspections and to confirm that additional thread degradation is not occurring in the RPV stud holes, Ameren Missouri commits to perform a one-time inspection of select RPV stud holes using a method consistent with the Babcock and Wilcox laser inspection that was applied following stud hole repair in 1989 and 1992. RPV stud hole locations 2, 4, 5, 7, 9, and 53 have had more than one thread removed and will be inspected. If inspection of these RPV stud holes confirms that there was minimal or no additional degradation since the prior video inspection, then it is a reasonable conclusion that there will be minimal additional degradation in the period of extended operation. If additional degradation is observed in any of the repaired stud holes where more than one thread has been removed, the condition will be entered in the Corrective Action Program for evaluation and corrective action, and the remaining repaired RPV stud hole locations 13, 25, 39, and 54 will be inspected. The inspection is expected to confirm that further degradation is not occurring in the repaired stud holes and will provide a basis for the conclusion that acceptance criteria for thread engagement will continue to be met through the period of extended operation.	B2.1.3	Implemented as part of proposed License Condition No. 3: Completed no later than 6 months prior to the period of extended operation or the refueling outage prior to the period of extended operation, whichever occurs later.	Letter ULNRC-06032 dated August 29, 2013 Letter ULNRC-06057 dated December 20, 2013
43	The core design procedure will be modified to include a review for the following core design parameters to ensure that these limits are met in future core designs: • Active fuel – upper core plate distance >12.2 inches • Average core power density <124 watts/cm^3 • Heat generation figure of merit, F ≤68 watts/cm^3 (Completed Amendment 31 dated February 14, 2014)	B2.1.6	Completed	Letter ULNRC-06072 dated January 16, 2014 Letter ULNRC-06080 dated February 14, 2014 Letter ULNRC-06090 dated March 13, 2014

Item Number	Commitment	FSAR Supplement Section/ LRA Section	Implementation Schedule	Source
44	For all MRP-191 Table 4-4 components, as applicable to Callaway, Ameren Missouri commits to perform one or more of the following resolution options for the non-CASS RVI components: Option 1: Replacement RVI components determined to be subject to 20% or greater cold work and 30 ksi operating stress will be replaced. Option 2: Inspection For RVI components determined to be subject to 20% or greater cold work and 30 ksi operating stress, an augmented inspection program capable of detecting cracking will be developed. Minimum examination coverage criteria consistent with MRP-227-A Primary Inspection Category Components will apply. The augmented inspection program will be submitted to the NRC prior to performance of the inspection(s). Option 3: Impact Evaluation For RVI components determined to be subject to 20% or greater cold work and 30 ksi operating stress, an impact evaluation will be prepared to establish that the effects of aging are minimal and will not have an adverse impact on future plant operability or component intended function. The impact evaluation(s) will be submitted to the NRC. Option 4: Mitigation RVI components determined to be subject to 20% or greater cold work and 30 ksi operating stress will be mitigated of stress corrosion cracking (SCC) susceptibility. Note: Indeterminate components will be conservatively assumed to be subject to 20% or greater cold work and subject to 30 ksi operating stress. (Closed, evaluation (ULNRC-06106, March 28, 2014) concluded that the plant-specific material fabrication and design are consistent with the MRP-191 basis and the MRP-227-A aging management requirements as related to cold work are directly applicable to Callaway Unit 1. Therefore, Options 1 – 4 are not necessary.	B2.1.6	Closed	Letter ULNRC-06079 dated February 5, 2014 Letter ULNRC-06106 dated March 28, 2014 Letter ULNRC-06117 dated April 23, 2014

Item Number	Commitment	FSAR Supplement Section/ LRA Section	Implementation Schedule	Source
45	Enhance the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program procedures to include the concrete structures in the turbine building that provide a flowpath for the circulating water system in the scope of the program. (Moved to Item 23 to be managed by the Structures Monitoring program – LRA Amendment 35 dated May 6, 2014)	See Commitment No. 23	Implemented as part of Commitment No. 23: Completed no later than 6 months prior to the period of extended operation.	Letter ULNRC-06080 dated February 14, 2014 Letter ULNRC-06118 dated May 6, 2014
46	Enhance the ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD Program to perform periodic inspection of the reactor vessel cladding indications identified in FSAR Section 5.2.3.2.2 SP and reconcile the inspection results with the corrosion analysis to ensure the analytical basis of the analysis is maintained.	4.7.3	Completed no later than 6 months prior to the period of extended operation. Inspections to be completed no later than 6 months prior to period of extended operation or the end of the last refueling outage prior to the period of extended operation, whichever occurs later.	Letter ULNRC-06118 dated May 6, 2014

APPENDIX B

CHRONOLOGY

This appendix contains a chronological listing of the routine correspondence between the staff of the U.S. Nuclear Regulatory Commission (the staff) and Union Electric Company, doing business as Ameren Missouri (the applicant) and other correspondence regarding the staff's reviews of the Callaway Plant Unit 1 (Callaway), Docket Number 50-483, license renewal application (LRA).

Date	Subject
December 15, 2011	Callaway Plant Unit 1—Letter from Reasoner III C.O., Ameren Missouri: Callaway, Unit 1, Application for Renewed Operating License (LDCN 11-0022). (Agencywide Documents Access and Management System (ADAMS) Accession No. ML113530367)
December 15, 2011	Callaway Plant Unit 1, License Renewal Application. (ADAMS Accession No. ML113530372)
December 15, 2011	Callaway Plant Unit 1, Applicant's Environmental Report; Operating License Renewal Stage Final, Cover through Chapter 2. (ADAMS Accession No. ML113540349)
December 15, 2011	Callaway Plant Unit 1, Applicant's Environmental Report; Operating License Renewal Stage Final, Chapter 3 through Attachment D. (ADAMS Accession No. ML113540352)
December 15, 2011	Callaway Plant Unit 1, Applicant's Environmental Report; Operating License Renewal Stage Final, Attachment E through End. (ADAMS Accession No. ML113540354)
December 23, 2011	Letter to Heflin A. C., Union Electric Company (Ameren Missouri): Receipt and Availability of the License Renewal Application for the Callaway Plant, Unit 1. (ADAMS Accession No. ML11343A060)
December 23, 2011	Federal Register Notice: Notice of Receipt and Availability of Application for Renewal of Callaway Plant, Unit 1. (ADAMS Accession No. ML11343A087)
December 29, 2011	Press Release-11-229: NRC Announces Availability of License Renewal Application for Callaway Nuclear Power Plant. (ADAMS Accession No. ML113630433)
February 14, 2012	Letter to Heflin A. C., Union Electric Company (Ameren Missouri): Determination of Acceptability and Sufficiency for Docketing, Proposed Review Schedule, and Opportunity for a Hearing Regarding the Application from Union Electric Company, for Renewal of the Operating License for Callaway Plant, Unit 1. (ADAMS Accession No. ML12024A262)
February 14, 2012	Letter to Heflin A. C., Union Electric Company (Ameren Missouri): Notice of Intent to Prepare an Environmental Impact Statement and Conduct Scoping Process for License Renewal for Callaway Plant, Unit 1. (ADAMS Accession No. ML12040A215)
February 14, 2012	Federal Register Notice: NRC Union Electric Company Notice of Intent to Prepare an Environmental Impact Statement and Conduct the Scoping Process for Callaway Plant, Unit 1. (ADAMS Accession No. ML12040A225)
February 16, 2012	Federal Register Notice: Notice of Opportunity for Hearing, Regarding Renewal of Facility Operating License No. NPF-30 for an Additional 20-Year Period, Federal Register Notice. (ADAMS Accession No. ML12024A254)
February 24, 2012	Meeting Notice: Forthcoming Meeting to Discuss the License Renewal Process and Environmental Scoping for Callaway Plant, Unit 1. (ADAMS Accession No. ML12041A479)
March 28, 2012	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Callaway Plant Unit 1 Union Electric Co. Facility Operating License NPF-30 License Renewal Application Online LR Library. (ADAMS Accession No. ML12088A351)
April 17, 2012	Letter to Heflin A. C., Union Electric Company (Ameren Missouri): Callaway Plant, Unit 1, License Renewal Application Online Reference Portal (TAC No. ME7708). (ADAMS Accession No. ML12104A191)

Date	Subject
April 23, 2012	Letter to Salveter A., U.S. Fish and Wild Service: Callaway Plant, Unit 1, License Renewal Application Environmental Review. (ADAMS Accession No. ML12103A209)
April 25, 2012	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Callaway Plant Unit 1 Union Electric Co. Facility Operating License NPF-30 Amendment 1 to Application for Renewed Operating License. (ADAMS Accession No. ML121170324)
May 3, 2012	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Callaway Plant Unit 1 Union Electric Co. Facility Operating License NPF-30 Amendment 2 to Application for Renewed Operating License. (ADAMS Accession No. ML12128A150)
May 31, 2012	Letter to Heflin A. C., Union Electric Company (Ameren Missouri): Project Manager Change for the License Renewal Project (Safety) for Callaway Plant, Unit 1 (TAC No. ME7708). (ADAMS Accession No. ML12139A058)
June 5, 2012	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Callaway Plant Unit 1 Union Electric Co. Facility Operating License NPF-30 Amendment 3 to Application for Renewed Operating License. (ADAMS Accession No. ML121580340)
June 11, 2012	Letter to Heflin A. C., Union Electric Company (Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application (TAC No. ME7708). (ADAMS Accession No. ML12144A035)
June 22, 2012	Letter to Heflin A. C., Union Electric Company (Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application (TAC No. ME7708). (ADAMS Accession No. ML12157A058)
June 22, 2012	Summary of Site Audit Related to the Review of the License Renewal Application for Callaway Plant, Unit 1 (TAC Nos. ME7715 and ME7716. (ADAMS Accession No. ML12159A154)
July 2, 2012	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Responses to RAI Set 1 and Amendment 4 to the Callaway LRA. (ADAMS Accession No. ML121850174)
July 5, 2012	Letter to Heflin A. C., Union Electric Company(Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application (TAC No. ME7708). (ADAMS Accession No. ML12164A905)
July 9, 2012	Letter to Heflin A. C., Union Electric Company (Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application, Set 4 (TAC No. ME7708). (ADAMS Accession No. ML12172A111)
July 18, 2012	Letter to Heflin A. C., Union Electric Company (Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application, Set 5 (TAC No. ME7708). (ADAMS Accession No. ML12179A400)
July 20, 2012	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Responses to RAI Set 2 to the Callaway LRA. (ADAMS Accession No. ML122021159)
August 6, 2012	Letter to Heflin A. C., Union Electric Company (Ameren Missouri): Scoping and Screening Methodology Audit Report Regarding the Callaway Plant, Unit 1, License Renewal Application (TAC No. ME7708). (ADAMS Accession No. ML12178A475)
August 6, 2012	Letter to Heflin A. C., Union Electric Company (Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application, Set 6 (TAC No. ME7708). (ADAMS Accession No. ML12206A264)
August 6, 2012	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Responses to RAI Set 3 and Amendment 5 to the Callaway LRA. (ADAMS Accession No. ML122200189)
August 9, 2012	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Responses to RAI Set 4 and Amendment 6 to the Callaway LRA. (ADAMS Accession No. ML122230044)
August 9, 2012	Letter to Heflin A. C., Union Electric Company (Ameren Missouri): Aging Management Programs Audit Report Regarding the Callaway Plant Unit 1 License Renewal Application (TAC No. ME7708). (ADAMS Accession No. ML12180A023)

Date	Subject
August 16, 2012	Letter to Heflin A. C., Union Electric Company(Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application, Set 7 (TAC No. ME7708). (ADAMS Accession No. ML12216A338)
August 21, 2012	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Responses to RAI Set 5 and Amendment 7 to the Callaway LRA. (ADAMS Accession No. ML122350582)
August 23, 2012	Letter to Heflin A. C., Union Electric Company(Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application, Set 8 (TAC No. ME7708). (ADAMS Accession No. ML12233A613)
September 6, 2012	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Responses to RAI Set 6 and Amendment 8 to the Callaway LRA. (ADAMS Accession No. ML122510211)
September 6, 2012	Letter to Heflin A. C., Union Electric Company(Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application, Set 9 (TAC No. ME7708). (ADAMS Accession No. ML12233A570)
September 12, 2012	Letter to Heflin A. C., Union Electric Company(Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application, Set 10, Public Version (TAC No. ME7708). (ADAMS Accession No. ML12284A454)
September 18, 2012	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Supplemental Responses to RAI Set 3 to the Callaway LRA. (ADAMS Accession No. ML122630080)
September 20, 2012	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Responses to RAI Set 7 and Amendment 9 to the Callaway LRA. (ADAMS Accession No. ML122690080)
September 20, 2012	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Responses to RAI Set 8 and Amendment 10 to the Callaway LRA. (ADAMS Accession No. ML122650037)
September 20, 2012	Letter to Heflin A. C., Union Electric Company(Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application, Set #11 (TAC No. ME7708). (ADAMS Accession No. ML12250A770)
September 25, 2012	Letter to Heflin A. C., Union Electric Company(Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application, Set #12 (TAC No. ME7708). (ADAMS Accession No. ML12256A895)
October 1, 2012	Letter to Heflin A. C., Union Electric Company(Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application, Set 13 (TAC No. ME7708). (ADAMS Accession No. ML12255A287)
October 3, 2012	Letter to Heflin A. C., Union Electric Company(Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application, Set 14 (TAC No. ME7708). (ADAMS Accession No. ML12270A147)
October 11, 2012	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Responses to RAI Set 9, Amendment 11, and Supplemental Responses to the Callaway LRA. (ADAMS Accession No. ML122860144)
October 12, 2012	Letter to Heflin A. C., Union Electric Company (Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application, Set 15 (TAC No. ME7708). (ADAMS Accession No. ML12276A373)
October 15, 2012	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Responses to RAI Set 10 and Amendment 12 to the Callaway LRA. (ADAMS Accession No. ML122900161)
October 24, 2012	Letter to Heflin A. C., Union Electric Company(Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application, Set 16 (TAC No. ME7708). (ADAMS Accession No. ML12286A235)
October 24, 2012	Letter from Kremer G. S., Union Electric Company (Ameren Missouri): Responses to RAI Set 11 and 12 and Amendment 13 to the Callaway LRA. (ADAMS Accession No. ML122990295)

Date	Subject
October 31, 2012	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Responses to RAI Sets 13 and 14 and Amendment 14 to the Callaway LRA. (ADAMS Accession No. ML123060389)
November 8, 2012	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Responses to RAI Set 15 and Amendment 15 to the Callaway LRA. (ADAMS Accession No. ML123140212)
November 20, 2012	Letter to Heflin A. C., Union Electric Company (Ameren Missouri): Callaway Plant – NRC License Renewal Inspection Report 05000483/2012009. (ADAMS Accession No. ML12328A053)
November 20, 2012	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Responses to RAI Set 16 and Amendment 16 to the Callaway LRA. (ADAMS Accession No. ML12328A088)
November 24, 2012	Letter to Heflin A. C., Union Electric Company(Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application, Set 17 (TAC No. ME7708). (ADAMS Accession No. ML12320A517)
November 29, 2012	Summary of Telephone Conference Call Held on September 27, 2012, Between the U.S. Nuclear Regulatory Commission and Union Electric Company (Ameren Missouri), Concerning Requests for Additional Information Pertaining to the Callaway Plant, Unit 1, License Renewal Application (TAC No. ME7708). (ADAMS Accession No. ML12321A199)
December 7, 2012	Letter to Heflin A. C., Union Electric Company(Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application, Set 18 (TAC No. ME7708). (ADAMS Accession No. ML12326A915)
December 13, 2012	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Responses to RAI Set 17 and Amendment 17 to the Callaway LRA. (ADAMS Accession No. ML123490272)
December 19, 2012	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Annual Update to the Callaway License Renewal Application Response to RAI Set #18. (ADAMS Accession No. ML123560157)
December 27, 2012	Letter to Heflin A. C., Union Electric Company(Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application, Set #19 (TAC No. ME7708). (ADAMS Accession No. ML12342A172)
January 10, 2013	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Response to RAI 2.3.4.2-1a and Amendment 19 to the Callaway LRA. (ADAMS Accession No. ML130110026)
January 14, 2013	Letter to Heflin A. C., Union Electric Company(Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application, Set 20 (TAC No. ME7708). (ADAMS Accession No. ML13009A211)
January 24, 2013	Letter from Kremer G. S., Union Electric Company (Ameren Missouri): Responses to RAI Sets 19 and 20 and Amendment 20 to the Callaway LRA. (ADAMS Accession No. ML130290353)
January 25, 2013	Letter to Heflin A. C., Union Electric Company (Ameren Missouri): Summary of the Public Meeting to Discuss the Results of the Callaway Nuclear Plant License Renewal Inspection. (ADAMS Accession No. ML13025A134)
January 30, 2013	Letter to Heflin A. C., Union Electric Company (Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application, Set 21 (TAC No. ME7708). (ADAMS Accession No. ML13025A031)
February 12, 2013	Summary of Telephone Conference Call Held on December 6, 2012, Between the U.S. Nuclear Regulatory Commission and Union Electric Company (Ameren Missouri), Concerning Requests for Additional Information Pertaining to the Callaway Plant, Unit 1, License Renewal Application (TAC No. ME7708). (ADAMS Accession No. ML13029A659)

Date	Subject
February 12, 2013	Summary of Telephone Conference Call Held on January 22, 2013, Between the U.S. Nuclear Regulatory Commission and Union Electric Company (Ameren Missouri), Concerning Requests for Additional Information Pertaining to the Callaway Plant, Unit 1, License Renewal Application (TAC No. ME7708). (ADAMS Accession No. ML13029A016)
February 14, 2013	Letter from McLachlan M., Union Electric Company (Ameren Missouri): Responses to RAI Set 21 and Amendment 21 to the Callaway LRA. (ADAMS Accession No. ML130460490)
February 21, 2013	Letter to Heflin A. C., Union Electric Company (Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application, Set 22 (TAC No. ME7708). (ADAMS Accession No. ML13038A308)
February 28, 2013	Letter from Kremer G. S., Union Electric Company (Ameren Missouri): Responses to RAI Set 22 and Amendment 22 to the Callaway LRA. (ADAMS Accession No. ML130630622)
March 20, 2013	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Commitment Regarding NFPA 805 Gap Analysis for the Callaway LRA. (ADAMS Accession No. ML13080A348)
March 26, 2013	Letter to Heflin A. C., Union Electric Company (Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application, Set 23 (TAC No. ME7708). (ADAMS Accession No. ML13042A042)
March 26, 2013	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Date Correction to RAI Set #22, Enclosure 1 Related to the Callaway LRA. (ADAMS Accession No. ML130860643)
March 29, 2013	Letter to Heflin A. C., Union Electric Company (Ameren Missouri): Request for Additional Information for the Review of the Callaway Plant, Unit 1 License Renewal Application, Set 24 (TAC No. ME7708). (ADAMS Accession No. ML13058A124)
April 1, 2013	Summary of Telephone Conference Call Held on August 23, 2012, Between the U.S. Nuclear Regulatory Commission and Union Electric Company (Ameren Missouri), Concerning Requests for Additional Information Pertaining to the Callaway Plant, Unit 1, License Renewal Application (TAC No. ME7708). (ADAMS Accession No. ML13067A316)
April 16, 2013	Summary of Telephone Conference Call Held on April 11, 2013, Between the U.S. Nuclear Regulatory Commission and Union Electric Company (Ameren Missouri), Concerning Requests for Additional Information Pertaining to the Callaway Plant, Unit 1, License Renewal Application (TAC No. ME7708). (ADAMS Accession No. ML13102A131)
April 23, 2013	Letter to Heflin A. C., Ameren Missouri: Safety Evaluation Report with Open Items Related to the License Renewal of Callaway Plant Unit 1 (TAC No. ME7708). (ADAMS Accession No. ML13086A224)
April 23, 2013	Memorandum to E. M. Hackett, Advisory Committee on Reactor Safeguards: ACRS Review of the Callaway Plant, Unit 1, LRA- SER With Open Items. (ADAMS Accession No. ML13098A149)
April 26, 2013	Letter from Kanuckel L. H., Union Electric Company (Ameren Missouri): Callaway, Unit 1, Responses to RAI Set #23 and Amendment 23 to the Callaway LRA. (ADAMS Accession No. ML13119A133)
April 26, 2013	Letter from Kanuckel L. H., Ameren Missouri: Callaway, Unit 1, Enclosure 1 to ULNRC-05979, License Renewal Application, Request for Additional Information(RAI) Set #23 Responses. (ADAMS Accession No. ML13119A136)
April 26, 2013	Letter from Kanuckel L. H., Ameren Missouri: Callaway, Unit 1, Enclosure 2 to ULNRC-05979, Amendment 23, LRA Changes from RAI Responses and Commitment Updates Enclosure 2 Summary Table. (ADAMS Accession No. ML13119A137)
April 29, 2013	Letter fromKanuckel L. H., Ameren Missouri: Callaway, Unit 1, Responses to RAI Set #24 and Amendment 24 to LRA. (ADAMS Accession No. ML13121A249)

Date	Subject
April 29, 2013	Letter from Kanuckel L. H., Ameren Missouri: Callaway, Unit 1, Enclosure 1 to ULNRC-05990, Responses to RAI Set # 24 and Amendment 24 to LRA and Enclosure 2, Amendment 24, LRA Changes from RAI Responses. (ADAMS Accession No. ML13121A250)
May 10, 2013	Letter from Reasoner, C. O., Ameren Missouri: Callaway, Unit 1 - Request to Delay Scheduled ACRS Subcommittee Meeting Date. (ADAMS Accession No. ML13134A304)
May 30, 2013	Letter to Heflin A. C., Ameren Missouri: Schedule Revision for the Safety Review of the Callaway Plant, Unit 1, LRA (TAC No. ME7708). (ADAMS Accession No. ML13141A748)
June 5, 2013	Letter from Kovaleski, S., Ameren Missouri: Callaway, Unit 1 - Review of Safety Evaluation with Open Items. (ADAMS Accession No. ML13156A351)
June 5, 2013	Letter from Kovaleski, S., Ameren Missouri: Callaway Plant, Unit 1 - Enclosure 1 to ULNRC-05994 - Technical Comments Regarding the Safety Evaluation Report (SER) with Open Items Related to the License Renewal . (ADAMS Accession No. ML13156A352)
June 5, 2013	Letter from Kovaleski, S., Ameren Missouri: Callaway, Unit 1 - Editorial Comments Regarding the Safety Evaluation Report (SER) with Open Items Related to the License Renewal. (ADAMS Accession No. ML13156A353)
July 12, 2013	Letter to Heflin A. C., Ameren Missouri: Request for Additional Information for the Review of the Callaway Plant, Unit 1, License Renewal Application, Set 25 (TAC No. ME7708). (ADAMS Accession No. ML13143A344)
August 2, 2013	Letter to Heflin A. C., Ameren Missouri: RAI Set 26. (ADAMS Accession No. ML13192A025)
August 2, 2013	Letter from McLachlan, M., Ameren Missouri: Callaway, Unit 1, Response to RAI Set #25 Amendment 25 to LRA. (ADAMS Accession No. ML13217A073)
August 2, 2013	Letter from McLachlan, M., Ameren Missouri: Callaway, Unit 1, Response to Request for Additional Information Set #25 on License Renewal Application. (ADAMS Accession No. ML13217A074)
August 29, 2013	Letter from McLachlan, M., Ameren Missouri: Callaway Plant Unit 1 - Response to RAI Set #26 and Amendment 26 to the Callaway LRA. (ADAMS Accession No. ML13242A290)
August 29, 2013	Letter from McLachlan, M., Ameren Missouri: Enclosure 1: Request for Additional Information (RAI) Set #26 Responses on License Renewal Application. (ADAMS Accession No. ML13242A291)
August 29, 2013	Letter from McLachlan, M., Ameren Missouri: Enclosure 2 - Amendment 26, LRA Changes. (ADAMS Accession No. ML13242A292)
September 20, 2013	Letter to Heflin A. C., Ameren Missouri: Callaway Plant, Unit 1, RAI Set 27 Rev 2. (ADAMS Accession No. ML13253A210)
October 17, 2013	Letter from Kremer, G. S., Ameren Missouri: Callaway, Unit 1, Response to RAI Set #27 (RAI B2.1.6-4c) and Amendment 27 to the Callaway LRA. (ADAMS Accession No. ML13295A108)
November 4, 2013	Letter to Heflin A. C., Ameren Missouri: Schedule Revision for the Safety Review of the Callaway Plant, Unit 1, License Renewal Application (TAC Nos. ME7708 and ME7716). (ADAMS Accession No. ML13281A781)
December 2, 2013	Letter to Heflin A. C., Ameren Missouri: Request for Additional Information for the Review of the Callaway Plant, Unit 1, License Renewal Application, Set 29 (TAC No. ME7708). (ADAMS Accession No. ML13330A689)
December 20, 2013	Letter from Kovaleski, S., Ameren Missouri: Callaway, Unit 1 - Annual Update to the Callaway License Renewal Application and Response to RAI Set #28. (ADAMS Accession No. ML13360A272)
December 20, 2013	Letter from Kovaleski, S., Ameren Missouri: Callaway, Unit 1, Enclosure 1 to ULNRC-06057, License Renewal Application - Request for Additional Information (RAI) Set #28 Responses. (ADAMS Accession No. ML13360A273)

Date	Subject
December 20, 2013	Letter from Kovaleski, S., Ameren Missouri: Callaway, Unit 1, Enclosure 2 to ULNRC-06057 - Amendment 28 LRA Change for LRA Annual Update and RAI Set 28. (ADAMS Accession No. ML13360A274)
December 20, 2013	Letter from Kovaleski, S., Ameren Missouri: Callaway, Unit 1, Enclosure 3 to ULNRC-06057, License Renewal Application - Summary of LRA Correspondence. (ADAMS Accession No. ML13360A275)
December 20, 2013	Letter fromKovaleski, S., Ameren Missouri: Callaway Plant, Unit 1, Enclosure 1 to ULNRC-06066, License Renewal Application, Request for Additional Information (RAI) Set #15 Responses Supplement to RAI B2.1.7-5A. (ADAMS Accession No. ML13360A302)
December 20, 2013	Letter from Kovaleski, S., Ameren Missouri: Callaway Plant, Unit 1, Supplement to RAI B2.1-7-5a. (ADAMS Accession No. ML13360A303)
January 16, 2014	Letter from Kovaleski, S., Ameren Missouri: Enclosure 1 to ULNRC-06072, Callaway Plant, Unit 1, Responses to Request for Additional Information (RAI) Sets #29 and #27 (RAI B2.1.6-4b). (ADAMS Accession No. ML14017A007)
January 16, 2014	Letter from Kovaleski, S., Ameren Missouri: Callaway Plant, Unit 1, Response to RAI Set #29, RAI Set #27 (RAI B2.1.6-4b), and Amendment 29 to the Callaway LRA. (ADAMS Accession No. ML14017A008)
February 4, 2014	Notice of Forthcoming Category 1 Meeting (February 20, 2014) with Union Electric Co. (Ameren Missouri) and Westinghouse to Discuss License Renewal for the Callaway Plant Unit 1. (ADAMS Accession No. ML14035A303)
February 5, 2014	Letter from Kovaleski, S., Ameren Missouri: Callaway Unit 1, Enclosure 1 to ULNRC-06079 - License Renewal Application, Supplemental Response to Request for Additional Information (RAI) Set #29 RAI B2.1.6-4d, Part (a). (ADAMS Accession No. ML14036A359)
February 5, 2014	Letter from Kovaleski, S., Ameren Missouri: Callaway Unit 1, Supplemental Response to RAI B2.1.6-4d, Part (a) and Amendment 30 to the License Renewal Application. (ADAMS Accession No. ML14036A360)
February 12, 2014	Letter to Diya, F., Ameren Missouri: Request for Additional Information for the Review of the Callaway Plant, Unit 1, License Renewal Application, Set 30 (TAC No. ME7708). (ADAMS Accession No. ML14029A192)
February 14, 2014	Letter from McLachlan, M., Ameren Missouri: Callaway, Unit 1, Amendment 31 to License Renewal Application Regarding Fire Protection. (ADAMS Accession No. ML14045A284)
February 14, 2014	Letter from McLachlan, M., Ameren Missouri: Callaway, Unit 1, Amendment 31 to License Renewal Application Change Regarding Fire Protection. (ADAMS Accession No. ML14045A285)
February 24, 2014	Letter to Diya, F., Ameren Missouri: Project Manager Change for the License Renewal of Callaway Plant, Unit 1 (TAC No. ME7708). (ADAMS Accession No. ML14052A230)
February 26, 2014	Letter to Diya, F., Ameren Missouri: Schedule Revision for the Safety Review of the Callaway Plant, Unit 1, License Renewal Application (TAC No. ME7708). (ADAMS Accession No. ML14050A020)
March 13, 2014	Letter from Kovaleski, S., Ameren Missouri: Callaway Plant Unit 1 Response to RAI Set 30 and Amendment 32 to LRA. (ADAMS Accession No. ML14073A003)
March 13, 2014	Letter from Kovaleski, S., Ameren Missouri: Enclosure 1: Callaway Plant Unit 1, Response to Request for Additional Information Set 30 and Updated Response to RAI B2.1.6-4d, Part (b). (ADAMS Accession No. ML14073A004)
March 13, 2014	Letter from Kovaleski, S., Ameren Missouri: Enclosure 2: Amendment 32, LRA Changes. (ADAMS Accession No. ML14073A005)
March 25, 2014	Summary of Telephone Conference Call Held January 28, 2014, Between NRC and Union Electric Company (Ameren Missouri), Pertaining to the Callaway Plant Unit 1, LRA. (ADAMS Accession No. ML14035A575)

Date	Subject
March 25, 2014	Letter to Diya, F., Ameren Missouri: Request for Additional Information for the Review of the Callaway Plant, Unit 1, License Renewal Application, Set 31 (TAC No. ME7708). (ADAMS Accession No. ML14065A592)
March 28, 2014	Letter from Kremer, G. S., Ameren Missouri: Callaway, Unit 1, Enclosure 1 to ULNRC-06106, Supplemental Response to Request for Additional Information (RAI) B2.1.6-4d, Part (a). (ADAMS Accession No. ML14087A091)
March 28, 2014	Letter from Kremer, G. S., Ameren Missouri: Callaway Plant, Unit 1, Supplemental Response to RAI B2.1.6-4d, Part (a) Related to Reactor Vessel Internals Cold Worked Material. (ADAMS Accession No. ML14087A092)
March 28, 2014	Letter from Gresham, J. A., Westinghouse: Attachment 3: Westinghouse Application for Withholding Proprietary Information from Public Disclosure CAW-14-3933, Accompanying Affidavit, Proprietary Information Notice, and Copyright Notice. (ADAMS Accession No. ML14093A775)
March 28, 2014	Letter from Gresham, J. A., Westinghouse: Attachment 1: Westinghouse Final Response to U.S. NRC RAI 3.1.2.1-6 (a) and (b) on the Callaway Nuclear Plant Reactor Lower Radial Support Clevis Insert Bolts (Proprietary). (ADAMS Accession No. ML14093A777)
March 28, 2014	Letter from Gresham, J. A., Westinghouse: Attachment 2: Westinghouse Final Response to U.S. NRC RAI 3.1.2.1-6 (a) and (b) on the Callaway Nuclear Plant Reactor Lower Radial Support Clevis Insert Bolts (Non-Proprietary). (ADAMS Accession No. ML14093A780)
March 31, 2014	Summary Of Meeting Held February 20, 2014, Between U.S. Nuclear Regulatory Commission Staff And Union Electric Company Representatives To Discuss The Callaway Plant, Unit 1, License Renewal Application (TAC No. ME7708). (ADAMS Accession No. ML14080A544)
April 3, 2014	Letter from Kovaleski, S., Ameren Missouri: Enclosure 1: Supplemental Response to RAI Set #30 (RAI 3.1.2.1-6). (ADAMS Accession No. ML14093A778)
April 3, 2014	Letter from Kovaleski, S., Ameren Missouri: Callaway, Unit 1 - Submittal of Supplemental Response to RAI Set #30 (RAI 3.1.2.1-6). (ADAMS Accession No. ML14093A781)
April 7, 2014	Summary of Telephone Conference Call Held 02/27/2014 and 03/04/2014, between Nuclear Regulatory Commission and Union Electric Company (Ameren Missouri), Pertaining to the Callaway Plant Unit 1, license renewal application RAI set 31. (ADAMS Accession No. ML14070A078)
April 11, 2014	Letter to Diya, F., Ameren Missouri: Regarding Ameren Missouri license renewal Amendment 31, National Fire Protection Association 805 changes to the Callaway Plant, Unit 1, license renewal application (TAC No. ME7708). (ADAMS Accession No. ML14083A617)
April 14, 2014	Summary of Telephone Conference Call Held January 30, 2014, between NRC and Union Electric Co., (Ameren Missouri), Concerning Requests for Additional Information Pertaining to Callaway, Unit 1, License Renewal Application. (ADAMS Accession No. ML14093B338)
April 15, 2014	Letter from Kovaleski, S., Ameren Missouri: Callaway Plant, Unit 1 - Supplement to the Callaway LRA - NFPA 805 Gap Analysis and LRA Amendment 33. (ADAMS Accession No. ML14105A475)
April 15, 2014	Letter from Kovaleski, S., Ameren Missouri: Callaway Plant, Unit 1 - License Renewal Application NFPA 805 Gap Analysis. (ADAMS Accession No. ML14105A476)
April 23, 2014	Letter from Kovaleski, S., Ameren Missouri: Callaway Plant, Unit 1, License Revewal Application, Request for Additional Information (RAI) Set 31 Responses. (ADAMS Accession No. ML14114A110)
April 23, 2014	Letter from Kovaleski, S., Ameren Missouri: Callaway Plant, Unit 1, Response to RAI Set #31 and Amendment 34 to the Callaway LRA. (ADAMS Accession No. ML14114A113)

Date	Subject
May 6, 2014	Letter from Kovaleski, S., Ameren Missouri: Callaway, Unit 1 - Updated RAI Response to the License Renewal Application Amendment 35. (ADAMS Accession No. ML14127A150)
May 6, 2014	Letter from Kovaleski, S., Ameren Missouri: Callaway, Unit 1 - Updated RAI Response to the License Renewal Application, Enclosures 1 and 2. (ADAMS Accession No. ML14127A151)
May 12, 2014	Memorandum to E. M. Hackett, Advisory Committee on Reactor Safeguards: Advisory Committee On Reactor Safeguards Review Of The Callaway Nuclear Plant License Renewal Application - Safety Evaluation Report. (ADAMS Accession No. ML14121A106)
June 5, 2014	Letter from Kovaleski, S., Ameren Missouri: Enclosure 1, Amendment 36, LRA Changes. (ADAMS Accession No. ML14156A312)
June 5, 2014	Letter from Kovaleski, S., Ameren Missouri: Callaway, Unit 1 - Amendment 36 to the Callaway LRA. (ADAMS Accession No. ML14156A313)
June 17, 2014	Letter from Kovaleski, S., Ameren Missouri: Callaway, Unit 1 - Amendment 37 to the Callaway LRA. (ADAMS Accession No. ML14168A360)
June 18, 2014	Summary of Telephone Conference Call Held November 25, 2013, between NRC and Union Electric Co., (Ameren Missouri), Concerning Requests for Additional Information Pertaining to Callaway, Unit 1, License Renewal Application (TAC ME7708). (ADAMS Accession No. ML14121A553)
July 8, 2014	Summary of Telephone Conference Call Held on October 2 and 3, 2013, between the U.S. Nuclear Regulatory Commission and Union Electric Co., (Ameren Missouri), Concerning Requests for Additional Information Pertaining to Callaway, Unit 1, License Renewal Application (TAC ME7708). (ADAMS Accession No. ML14175B499)
August 20, 2014	Summary of Telephone Conference Call Held November 26, 2013, between NRC and Union Electric Co., (Ameren Missouri), Concerning Requests for Additional Information Pertaining to Callaway, Unit 1, License Renewal Application (TAC ME7708). (ADAMS Accession No. ML14223A532)
August 20, 2014	Summary of Telephone Conference Call Held December 18, 2013, between the U.S. Nuclear Regulatory Commission and Union Electric Co., (Ameren Missouri), Concerning Requests for Additional Information Pertaining to Callaway, Unit 1, License Renewal Application (TAC ME7708). (ADAMS Accession No. ML14223A602)

APPENDIX C

PRINCIPAL CONTRIBUTORS

This appendix lists the principal contributors for the development of this safety evaluation report (SER) and their areas of responsibility.

Name	Responsibility
Principal Contributors	
Armstrong, Garry	Reviewer – Scoping & Screening
Auluck, Rajender	Management Oversight
Brittner, Don	Reviewer – Mechanical
Buford, Angela	Reviewer – Structural
Casto, Greg	Management Oversight
Dennig, Robert	Management Oversight
Doutt, Cliff	Reviewer – Electrical
Erickson, Alice	Reviewer – Structural
Cuadrado, Samuel	Project Management
Daily, John	Project Management
Yoira Diaz-Sanabria	Management Oversight
Fu, Bart	Reviewer – Mechanical
Gall, Jennifer	Reviewer – Scoping & Screening
Galloway, Melanie	Management Oversight
Gavula, Jim	Reviewer – Mechanical
Ghasemian, Shahram	Management Oversight
Giitter, Joseph	Management Oversight
Green, Kim	Reviewer – Mechanical
Hiland, Pat	Management Oversight
Hiser, Allen	Management Oversight
Holston, Bill	Reviewer – Mechanical
Hovanec, Chris	Reviewer – Mechanical
Hunt, Christopher	Reviewer – Mechanical
Iqbal, Naeem	Reviewer – Fire Protection
Jackson, Christopher	Management Oversight
Kalikian, Roger	Reviewer – Mechanical
Karwoski, Kenneth	Management Oversight
Kichline, Michelle	Reviewer – Mechanical
Klein, Alex	Management Oversight
Klos, John	Reviewer – Mechanical
Kulesa, Gloria	Management Oversight
Lehman, Bryce	Reviewer – Structural
Li, Rui	Reviewer – Electrical
Lubinski, John	Management Oversight
Mathew, Roy	Management Oversight
Marshall, Michael	Management Oversight
McGinty, Tim	Management Oversight

Name	Responsibility
Medoff, Jim	Reviewer – Mechanical
Min, Seung	Reviewer – Mechanical
Morey, Dennis	Management Oversight
Murphy, Martin	Management Oversight
Ng, Ching	Reviewer – Mechanical
Nguyen, Duc	Reviewer – Electrical
Obodoako, Aloysius	Reviewer – Mechanical
Parks, Benjamin	Reviewer – Neutron Fluence
Pham, Bo	Management Oversight
Prinaris, Andrew	Reviewer – Structural
Raval, Janak	Reviewer – Scoping & Screening
Rogers, Bill	Reviewer – Scoping & Screening Methodology
Rosenberg, Stacey	Management Oversight
Sheikh, Abdul	Reviewer – Structural
Smith, Ed	Reviewer – Scoping & Screening
Sun, Robert	Reviewer – Mechanical
Sydnor, Christopher	Reviewer – Mechanical
Torres, Roberto	Reviewer – Scoping & Screening
Wise, John	Reviewer – Mechanical
Wong, Emma	Reviewer – Mechanical
Yee, On	Reviewer – Mechanical
Contractors	
BLH Technologies, Inc.	SER Support
Oak Ridge National Laboratory	Review – Structural

APPENDIX D

REFERENCES

This appendix lists the references used throughout this safety evaluation report for review of the license renewal application for Callaway Plant Unit 1.

U.S. Nuclear Regulatory Commission Documents
U.S. Nuclear Regulatory Commission (U.S. NRC) IE Bulletin 87-01, “Thinning in Pipe Walls in Nuclear Power Plants,” July 1987.
U.S. NRC Bulletin 88-09, “Thimble Tube Thinning in Westinghouse Reactors,” July 1988.
U.S. NRC Bulletin 88-11, “Revised Fatigue Analysis of the Pressurizer Surge Line for Thermal Cycling and Stratification,” December 1988.
Generic Letter (GL) 88-05, “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants,” March 1988.
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