IPRenewal NPEmails

From: Green, Kimberly
Sent: Wednesday, August 12, 2009 12:19 PM
To: Santos, Cayetano
Cc: Wen, Peter
Subject: IP Final SER
Attachments: IP Final Safety Evaluation Report.pdf

Tanny,

Attached is the IP Final SER which is scheduled to be discussed at the Full Committee ACRS Meeting on September 10th.

I will bring over 15 cds and 3 printed copies as requested.

Please let me know if you have any questions.

Kimberly Green
Safety PM
(301) 415-1627
kimberly.green@nrc.gov

Hearing Identifier: IndianPointUnits2and3NonPublic_EX
Email Number: 1631

Mail Envelope Properties (Kimberly.Green@nrc.gov20090812121800)

Subject: IP Final SER
Sent Date: 8/12/2009 12:18:48 PM
Received Date: 8/12/2009 12:18:00 PM
From: Green, Kimberly

Created By: Kimberly.Green@nrc.gov

Recipients:
"Wen, Peter" <Peter.Wen@nrc.gov>
Tracking Status: None
"Santos, Cayetano" <Cayetano.Santos@nrc.gov>
Tracking Status: None

Post Office:

Files	**Size**	**Date & Time**
MESSAGE	382	8/12/2009 12:18:00 PM
IP Final Safety Evaluation Report.pdf	2174879	

Options
Priority: Standard
Return Notification: No
Reply Requested: No
Sensitivity: Normal
Expiration Date:
Recipients Received:

Safety Evaluation Report

Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3

Docket Nos. 50-247 and 50-286

Entergy Nuclear Operations, Inc.

United States Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

August 2009

THIS PAGE INTENTIONALLY LEFT BLANK.

ABSTRACT

This safety evaluation report (SER) documents the technical review of the Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3), license renewal application (LRA) by the U.S. Nuclear Regulatory Commission (NRC) staff (the staff). By letter dated April 23, 2007, and as supplemented by letters dated May 3 and June 21, 2007, Entergy Nuclear Operations, Inc., (Entergy or the applicant) submitted the LRA in accordance with Title 10, Part 54, of the *Code of Federal Regulations*, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants.” Entergy requests renewal of the IP2 and IP3 operating licenses (Facility Operating License Numbers DPR-26 and DPR-64, respectively) for a period of 20 years beyond the current expirations at midnight on September 28, 2013, for IP2, and at midnight on December 12, 2015, for IP3.

Indian Point is located approximately 24 miles north of the New York City boundary line. The NRC issued the construction permits on October 14, 1966 for IP2, and on August 13, 1969, for IP3. The NRC issued the operating licenses on September 28, 1973 for IP2, and on December 12, 1975, for IP3. IP2 and IP3 employ a pressurized water reactor design with a dry ambient containment. Westinghouse Electric Corporation supplied the nuclear steam supply system and Westinghouse Development Corporation originally designed and constructed the balance of the plant with the assistance of its agent, United Engineers and Constructors. The licensed power output of each unit is 3216 megawatts thermal (MWt) with a gross electrical output of approximately 1080 megawatts electric (MWe).

On January 15, 2009, the staff issued an SER with Open Items Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3, in which the staff identified 20 open items necessitating further review. This SER presents the status of the staff’s review of information submitted through August 6, 2009, the cutoff date for consideration in this SER. The 20 open items that had been identified in the previous SER were resolved before the staff made a final determination on the LRA. SER Section 1.5 summarizes these items and their resolution. Section 6.0 provides the staff’s final conclusion on its review of the IP2 and IP3 LRA.

<u>THIS PAGE INTENTIONALLY LEFT BLANK.</u>

TABLE OF CONTENTS

Appendices

List of Tables

ABBREVIATIONS

AC	alternating current
ACAR	aluminum conductor aluminum-reinforced
ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards
ACSR	aluminum core steel-reinforced
ADAMS	Agencywide Document Access and Management System
ADV	atmospheric dump valve
AEIC	Association of Edison Illuminating Companies
AERM	aging effect requiring management
AFW	auxiliary feedwater
AISC	American Institute of Steel Construction
AMP	aging management program
AMR	aging management review
AMSAC	ATWS Mitigating System Actuation Circuitry
ANSI	American National Standards Institute
APCSB	Auxiliary and Power Conversion Systems Branch
ART	adjusted reference temperature
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATWS	anticipated transient without scram
B&PV	Boiler and Pressure Vessel
BADGER	boron-10 areal density gauge for evaluating racks
BIL	basic impulse level
BMI	bottom mounted instrumentation
BOP	balance of plant
BTP	branch technical position
BVS	building vent sampling
BWR	boiling water reactor
C	Celsius
CASS	cast austenitic stainless steel
CB	core barrel
CCW	component cooling water
CEA	control element assembly
CETNA™	core exit thermocouple nozzle assembly
CFR	*Code of Federal Regulations*
CII	containment inservice inspection
CL	chlorination system
CLB	current licensing basis
CO_2	carbon dioxide

CR	condition report
CRD	control rod drive
CRDM	control rod drive mechanism
Cr-Mo	chromium-molybdenum
CS	containment spray
CST	condensate storage tank
Cu	copper
CUF	cumulative usage factor
CVCS	chemical and volume control
C_VUSE	Charpy upper-shelf energy
CW	circulating water
CWM	IP3 city water system code
CYW	IP2 city water system code
DBA	design basis accident
DBD	design basis document
DBE	design basis event
DC	direct current
ECCS	emergency core cooling system
ECT	eddy current testing
EDG	emergency diesel generator
EFPY	effective full-power year
EMA	equivalent margin analysis
EN	shelter or protection
EPRI	Electric Power Research Institute
EQ	environmental qualification, environmentally qualified
EQAP	Entergy Quality Assurance Program
ER	Environmental Report (Applicant's Environmental Report Operating License Renewal Stage)
ESF	engineered safety features
F	Fahrenheit
FAC	flow accelerated corrosion
F_{en}	environmental fatigue life correction factor
FERC	Federal Energy Regulatory Commission
FLB	flood barrier
FLT	filtration
FMP	Fatigue Monitoring Program
FR	*Federal Register*
FRV	feedwater regulating valve
FSAR	final safety analysis report
ft-lb	foot-pound
FW	feedwater
FWST	fire water storage tank
GALL	Generic Aging Lessons Learned Report
GDC	general design criteria or general design criterion
GEIS	Generic Environmental Impact Statement
GL	generic letter

GSI	generic safety issue
GT	gas turbine
H_2	hydrogen
HELB	high-energy line break
HEPA	high efficiency particulate air
HPSI	high pressure safety injection
HVAC	heating, ventilation, and air conditioning
HX	heat exchanger
I&C	instrumentation and controls
IA	instrument air
IASCC	irradiation assisted stress corrosion cracking
IEEE	Institute of Electrical and Electronics Engineers
IGA	intergranular attack
IGSCC	inter-granular stress corrosion cracking
ILRT	integrated leak rate testing
IN	information notice
INPO	Institute of Nuclear Power Operations
IP1	Indian Point Nuclear Generating Unit 1
IP2	Indian Point Nuclear Generating Unit 2
IP3	Indian Point Nuclear Generating Unit 3
IP	Indian Point (site)
IPA	integrated plant assessment
IPEC	Indian Point Energy Center
ISG	interim staff guidance
ISI	inservice inspection
ISO	International Standards Organization
ksi	kip per square inch
KV or kV	kilo-volt
lb	pound
LBB	leak before break
LO	lube oil
LOCA	loss of coolant accident
LRA	license renewal application
μmhos/cm	micromhos per centimeter
MB	missile barrier
MC	ASME Class for metal containment components
MEB	metal-enclosed bus
MFW	main feedwater
MIC	microbiologically influenced corrosion
MOV	motor-operated valve
MPa	megapascal
MRP	Materials Reliability Program
MS	main steam
MSIV	main steam isolation valve
MWe	megawatts-electric

MWt	megawatts-thermal
n/cm^2	neutrons per square centimeter
NaOH	sodium hydroxide
NDE	nondestructive examination
NEI	Nuclear Energy Institute
NESC	National Electric Safety Code
NFPA	National Fire Protection Association
Ni	nickel
NPS	nominal pipe size
NRC	US Nuclear Regulatory Commission
NSAC	Nuclear Safety Analysis Center
NSAS	nonsafety system affecting safety system
NSSS	nuclear steam supply system
NYPA	New York Power Authority
O_2	oxygen
ODSCC	outside-diameter stress corrosion cracking
OI	open item
P&ID	piping and instrumentation diagram
PAB	primary auxiliary building
PB	pressure boundary
PBD	program basis document
pH	potential of hydrogen
PM	preventive maintenance
PORV	power-operated relief valve
ppb	parts per billion
ppm	parts per million
psi	pound per square inch
psig	pound-force per square inch gauge
PSPM	periodic surveillance and preventive maintenance
P-T	pressure-temperature
PTS	pressurized thermal shock
PVC	polyvinyl chloride
PW	primary water makeup
PWR	pressurized water reactor
PWSCC	primary water stress corrosion cracking
QA	quality assurance
RAI	request for additional information
RCCA	rod cluster control assembly
RCIC	reactor core isolation cooling
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RG	regulatory guide
RHR	residual heat removal
RI-ISI	risk-informed inservice inspection

RO	refueling outage
RPV	reactor pressure vessel
RT_{NDT}	reference temperature nil ductility transition
RT_{PTS}	reference temperature for pressurized thermal shock
RTD	resistance temperature detector
RVCH	reactor vessel closure head
RVI	reactor vessel internals
RVID	Reactor Vessel Integrity Database
RVLIS	reactor vessel level indication system
RW	river water
RWST	refueling water storage tank
S&PC	steam and power conversion
S_A	stress allowables
SAR	safety analysis report
SBO	station blackout
SC	structure and component
SCC	stress-corrosion cracking
SER	safety evaluation report
SFP	spent fuel pool
SFPC	spent fuel pit/pool cooling
SG	steam generator
SGBD	steam generator blowdown
SI	safety injection
SMP	structures monitoring program
SO_2	sulfur dioxide
SOC	statement of consideration
SOV	solenoid-operated valve
SPU	stretch power uprate
SR	surveillance requirement
SRP-LR	Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants
SS	stainless steel
SSC	system, structure, and component
SSE	safe-shutdown earthquake
SSFS	safety system function sheets
SW	service water
TLAA	time-limited aging analysis
TS	technical specification(s)
TSC	technical support center
UFSAR	Updated Final Safety Analysis Report
USE	upper-shelf energy
UT	ultrasonic testing
UV	ultraviolet
V	volt
VCT	volume control tank

WCAP	Westinghouse Commercial Atomic Power
WOG	Westinghouse Owners Group
XLPE	cross-linked polyethylene
yr	year
Zn	zinc
1/4 T	one-fourth of the way through the vessel wall measured from the internal surface of the vessel

THIS PAGE INTENTIONALLY LEFT BLANK.

SECTION 1

INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

This document is a safety evaluation report (SER) on the license renewal application (LRA) for Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3), as filed by Entergy Nuclear Operations, Inc. (Entergy or the applicant). By letter dated April 23, 2007, and as supplemented by letters dated May 3 and June 21, 2007, Entergy submitted its application to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the Indian Point (IP) operating licenses for an additional 20 years. The NRC staff (the staff) prepared this report to summarize the results of its safety review of the LRA for compliance with Title 10, Part 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants,” of the *Code of Federal Regulations* (10 CFR Part 54). The NRC project manager for the license renewal review is Kim Green. Ms. Green may be contacted by telephone at 301-415-1627 or by electronic mail at Kimberly.Green@nrc.gov. Alternatively, written correspondence may be sent to the following address:

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

In its April 23, 2007, submission letter, the applicant requested renewal of the operating licenses issued under Section 104b (Operating License Nos. DPR-26 and DPR-64) of the Atomic Energy Act of 1954, as amended, for IP2 and IP3 for a period of 20 years beyond the current expirations at midnight on September 28, 2013, for IP2, and at midnight on December 12, 2015, for IP3. Indian Point is located approximately 24 miles north of the New York City boundary line. The NRC issued the construction permits on October 14, 1966, for IP2, and on August 13, 1969, for IP3. The NRC issued the operating licenses on September 28, 1973, for IP2, and on December 12, 1975, for IP3. IP2 and IP3 employ a pressurized water reactor design with a dry ambient containment. Westinghouse Electric Corporation supplied the nuclear steam supply system and Westinghouse Development Corporation originally designed and constructed the balance of the plant with the assistance of its agent, United Engineers and Constructors. The licensed power output of each unit is 3216 megawatt thermal (MWt) with a gross electrical output of approximately 1080 megawatt electric (MWe). The updated final safety analysis reports (UFSARs) contain details of the plants and the site.

During its docketing sufficiency review, the staff identified two areas which required clarification from the applicant. The first issue was related to the name by which the applicant referred to the plant and the operating units. As noted in the LRA, the applicant refers to the operating units as Indian Point Energy Center Unit 2 and Unit 3. By letter dated May 3, 2007, the applicant clarified that the name "Indian Point Energy Center Units 2 and 3" is synonymous with the name "Indian Point Nuclear Generating Unit Nos. 2 and 3." The second issue was related to the proposed installation of the IP2 station blackout (SBO)/Appendix R diesel generator. By letter dated June 18, 2007, the staff notified Entergy that the staff believed that the current licensing basis for IP2 was not fully represented in accordance with Section 54.4(a)(3) of Title 10 of the *Code of*

Federal Regulations (10 CFR 54.4(a)(3)). The staff determined that the applicant had not included within the scope of license renewal those systems, structures, and components relied on in the safety analyses or plant evaluations to perform a function that demonstrates compliance with the requirements for station blackout (SBO) per 10 CFR 50.63, and safe shutdown per 10 CFR 50.48. In this regard, the LRA did not include information on the gas turbines, which at the time of submittal, were credited as an alternate power supply for the Appendix R and SBO events. Therefore, the staff requested that Entergy inform the staff of its plans to resolve this issue. By letter dated June 21, 2007, Entergy supplemented the LRA, and committed that the IP2 SBO/Appendix R diesel generator would be installed and operational by April 30, 2008. The applicant determined that the committed change to the facility met the requirements of 10 CFR 50.59(c)(1) and, therefore, a license amendment pursuant to 10 CFR 50.90 was not required. By letter dated July 25, 2007, the staff notified Entergy that it had completed its sufficiency review and that the application was acceptable for docketing.

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 IP license renewal is based on the applicant’s LRA, amendments to the LRA, and on its responses to the staff’s requests for additional information. On January 15, 2009, the staff issued an SER with Open Items Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3, in which the staff identified 20 open items necessitating further review. Thereafter, the applicant supplemented the LRA and provided clarifications through its responses to the staff’s RAIs and docketed correspondence. Unless otherwise noted, the staff reviewed and considered information submitted through August 6, 2009. The staff reviewed certain information received after that date as necessary and appropriate. The public may view the LRA and all pertinent information and materials, including the UFSARs, 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). Copies of the LRA are also available at White Plains Public Library, 100 Martine Avenue, White Plains, NY 10601, at Field Library, 4 Nelson Avenue, Peekskill, NY 10566, and at Hendrick Hudson Free Library, 185 Kings Ferry Rd., Montrose, NY 10548. In addition, the public may find the LRA, as well as materials related to the license renewal review, on the NRC Web site at http://www.nrc.gov.

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

SER Sections 2 through 4 address the staff’s evaluation of license renewal issues considered during the review of the application. SER Section 5 is reserved for the report provided of the Advisory Committee on Reactor Safeguards (ACRS), which is expected to be issued subsequent to the publication of this SER. The conclusions of this SER are in Section 6.

SER Appendix A is a table showing the applicant’s commitments for renewal of the operating licenses. SER Appendix B is a chronology of the principal correspondence between the staff and the applicant regarding the LRA safety 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 issued the draft, plant-specific Supplement 38 to NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Indian Point Nuclear Generating Unit Nos. 2 and 3 Draft Report for Comment," Volumes 1 and 2, on December 22, 2008. The supplement discusses the environmental considerations related to license renewal for IP2 and IP3. The draft Supplement is available on the NRC website (http://www.nrc.gov/reactors/operating/licensing/renewal.html).

1.2 License Renewal Background

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

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

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

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

1.2.1 Safety Review

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

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

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

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

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

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

License renewal also requires TLAA identification. During the plant design phase, certain assumptions about the length of time the plant may 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 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 utilized the process defined in NUREG-1801, Revision 1, "Generic Aging Lessons Learned (GALL) Report," dated September 2005. The GALL Report summarizes staff-approved aging management programs (AMPs) for many SCs subject to an AMR. If an applicant commits to implementing these staff-approved AMPs, the time, effort, and resources for LRA review can be greatly reduced, improving the efficiency and effectiveness of the license renewal review process. The GALL Report summarizes the aging management evaluations, programs, and activities credited for managing aging for most of the SCs used by nuclear power plants. The report is also a quick reference for both applicants and staff reviewers with respect to AMPs and activities that can manage aging adequately during the period of extended operation.

1.2.2 Environmental Review

Part 51 of 10 CFR contains regulations pertaining to 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 of 10 CFR Part 51, as Category 1 issues. Pursuant to 10 CFR 51.53(c)(3)(i), a license renewal applicant may incorporate these generic findings in its environmental report. In accordance with 10 CFR 51.53(c)(3)(ii), an environmental report also must include analyses of environmental impacts that must be evaluated on a plant-specific basis (i.e., Category 2 issues).

In accordance with the National Environmental Policy Act of 1969 and 10 CFR Part 51, the staff reviewed the plant-specific environmental impacts of license renewal, including any new and significant information not considered in the GEIS. As part of its scoping process, the staff held a public meeting on September 19, 2007 at the Colonial Terrace in Cortlandt Manor, New York, to identify plant-specific environmental issues. The draft, plant-specific Supplement 38 to the GEIS documents the results of the environmental review and makes a preliminary recommendation as to the license renewal action, based on environmental considerations. The staff held additional public meetings on February 12, 2009, in Cortlandt Manor, New York, to receive comments on the draft, plant-specific GEIS Supplement 38. The staff received numerous comments concerning the draft supplement. The staff plans to issue the final supplement in February 2010.

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 performed in accordance with 10 CFR Part 54 requirements and NRC guidance. 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 of the Indian Point LRA.

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

Pursuant to 10 CFR 54.19(b), the NRC requires that the LRA include "conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license." On this issue, the applicant stated in the LRA:

> The agreement shall terminate at the time of expiration of the 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 revised by Amendment No. 25, lists IPEC operating license numbers DPR-26 and DPR-64. The applicants request that conforming changes be made to Article VII of the indemnity agreement, and Item 3 of the Attachment to that agreement, specifying the extension of agreement until the expiration date of the renewed IPNG facility operating license sought in this application. In addition, should the license number be changed upon issuance of the renewal license, the applicants request that conforming changes be made to Item 3 of the Attachment, and other sections of the indemnity agreement as appropriate.

The staff intends to maintain the original license numbers upon issuance of the renewed licenses, if approved. Therefore, conforming changes to the indemnity agreement need not be made and the 10 CFR 54.19(b) requirements have been met.

Pursuant to 10 CFR 54.21, "Contents of Application - Technical Information," the NRC requires that the LRA contain (a) an integrated plant assessment, (b) a description of any CLB changes during the NRC'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) and (c). LRA Appendix A satisfies the license renewal requirements of 10 CFR 54.21(d).

Pursuant to 10 CFR 54.21(b), the NRC requires that, each year following submission of the LRA and at least three months before the scheduled completion of the NRC's review, the applicant submit an LRA amendment identifying any CLB changes to the facility that materially affect the contents of the LRA, including the FSAR supplement. By letter dated June 11, 2008, the applicant submitted an LRA update which summarizes the CLB changes that have occurred during the staff's review of the LRA.

Pursuant to 10 CFR 54.22, "Contents of Application - Technical Specifications," the NRC requires that the LRA include changes or additions to the technical specifications (TS) that are necessary to manage aging effects during the period of extended operation. In LRA Appendix D, the applicant stated that it had not identified any TS changes necessary for issuance of the renewed IP operating licenses. 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 regulatory 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 SER will be referred to the ACRS, and 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

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

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

Table 1.4-1 Current and Proposed Interim Staff Guidance

ISG Issue (Approved ISG Number)	Purpose	SER Section
Nickel-alloy components in the reactor coolant pressure boundary (LR-ISG-19B)	To address the cracking of nickel-alloy components in the reactor pressure boundary. This ISG is currently under development. NEI and EPRI-MRP will develop an augmented inspection program for GALL AMP XI.M11-B. This AMP will not be completed until the NRC approves an augmented inspection program for nickel-alloy base metal components and welds as proposed by EPRI-MRP.	SER Section 3.0.3.3.5
Changes to Generic Aging Lesson Learned (GALL) Report Aging Management Program (AMP) XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements" (LR-ISG-2007-02)	To address the frequency of inspection of electrical cable connections not subject to 10 CFR 50.49 prior to the period of extended operation. The staff issued the proposed ISG for public comment. A final ISG has not yet been issued.	SER Section 3.0.3.3.6
Staff Guidance Regarding the Station Blackout Rule (10 CFR 50.63) Associated with License Renewal Applications (LR-ISG-2008-01)	To clarify the scoping boundary of the offsite recovery paths that must be included within the scope of license renewal for station blackout. The staff issued the proposed ISG for public comments. On July 7, 2009, the staff withdrew LR-ISG-2008-01. See 74 FR 33478, dated July 13, 2009.	Not applicable

1.5 Summary of Open Items

On January 15, 2009, at the time the SER with Open Items was issued, the staff identified the following open items (OIs). An item was considered open if, in the staff's judgment, it has not been shown to meet all applicable regulatory requirements at the time of the issuance of the SER. The staff assigned a unique identifying number to each OI. By letters dated January 29, May 1, and June 12, 2009, the applicant provided additional information which enabled the staff to close out the open items.

OI 2.3A.3.11-1: (SER Section 2.3A.3.11 – IP2 Fire Protection – Water)

In LRA Section 2.3.3.11, the applicant lists the component types that require aging management review. However, some components were not included in the list that are either referenced in the applicant's current licensing basis documents or are shown on the license renewal drawings. Therefore, in RAI 2.3A.3.11-2, the staff asked the applicant to determine whether the components listed in the RAI should be included as component types subject to an AMR, and if not, to justify the exclusion. By letter dated November 16, 2007, the applicant stated that yard hose houses and chamber housings are not subject to an aging management review (AMR) because failure of these components will not result in a failure of the fire suppression function of the associated fire hydrant and the sprinkler system, respectively. The yard hose houses and chamber housings are passive, long-lived components that were identified as within the scope of license renewal. Therefore, the staff considers that these components are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff indicated that the applicant should justify why the yard hose houses and chamber housings are not subject to an AMR.

By letter dated January 27, 2009, the applicant stated that yard hose houses and chamber housings provide no function that supports 10 CFR 50.48 requirements; therefore, they are not within the scope of license renewal. The closure of this item is documented in SER Section 2.3A.3.11.2.

OI 2.3.4.2-1: (SER Sections 2.3A.4.2 and 2.3B.4.2 – Main Feedwater System)

IP2 (SER Section 2.3A.4.2 – IP2 Main Feedwater System):

UFSAR Section 14.2.5.6, Containment Peak Pressure for a Postulated Steam Line Break, indicates that for IP2 the applicant takes credit for the main feedwater stop valves, BFD-5's, to close within 120 seconds, in the event of the failure of the main feedwater control valve.

In its revised response to RAI 2.3A.4.2-1 regarding feedwater isolation valves, dated March 24, 2008, the applicant stated that the feedwater valves credited for feedwater isolation are safety-related and, although not highlighted on the license renewal drawing, these valves and the remainder of the feedwater system components on the associated license renewal drawing are within scope of license renewal and are subject to an AMR based upon meeting the requirements of 10 CFR 54.4(a)(2) because of their potential for spatial interaction with safety-related equipment. Based upon the staff's understanding of the applicant's UFSAR, the main feedwater stop valves (BFD-5's), have an intended function that meets the criteria of 10 CFR 54.4(a)(1); however, these valves are neither included within the "system intended function boundary," nor are they highlighted on the license renewal drawings for having an intended function in accordance with 10 CFR 54.4(a)(1).

By letter dated December 30, 2008, the staff requested the applicant to justify the exclusion of the main feedwater stop valves (BFD-5's), from the scope of license renewal in accordance with 10 CFR 54.4(a)(1).

By letter dated January 27, 2009, the applicant explained that the BFD-5 isolation valves are nonsafety-related components, and consistent with the requirements in 10 CFR 54.4(a)(2), the valves are included in the scope for license renewal. The closure of this item is documented in SER Section 2.3A.4.2.2.

IP3 (SER Section 2.3B.4.2 – IP3 Main Feedwater System):

UFSAR Section 14.2.5, Rupture of a Steam Pipe, states in the event of a main steam line break incident, the motor-operated valves (MOVs) associated with each of the feedwater regulating valves (FRVs) also will close. The mechanical stroke time of 120 seconds to close these associated MOVs has been analyzed and is acceptable. License renewal drawing 9321-20193 shows a "HIGH STEAM FLOW SI LOGIC" signal goes to these MOVs (BFD-90's). UFSAR Section 14.2.5.1 states that redundant isolation of the main feedwater lines is necessary, because sustained high feedwater flow would cause additional cooldown. Therefore, in addition to the normal control action which will close the main feedwater valves, any safety injection signal will rapidly close all feedwater control valves (including the motor-operated block valves and low-flow bypass valves), trip the main feedwater pumps, and close the feedwater pump discharge valves.

The motor-operated block valves shown on license renewal drawings are BFD-5s and BFD-90s for the main FRVs, and the low flow bypass regulating valves, respectively. The feedwater isolation valves, BFD-5's and BFD-90's, are not included within the "system intended function boundary," nor are they highlighted on the license renewal drawings for having an intended function in accordance with 10 CFR 54.4(a)(1).

By letter dated December 30, 2008, the staff requested the applicant to justify the exclusion of the isolation valves, BFD-5's and BFD-90's, from the scope of license renewal in accordance with 10 CFR 54.4(a)(1).

By letter dated January 27, 2009, the applicant explained that the BFD-5 and BFD-90 isolation valves are nonsafety-related components, and consistent with the requirements in 10 CFR 54.4(a)(2), the valves are included in the scope for license renewal. The closure of this item is documented in SER Section 2.3B.4.2.2.

<u>OI 2.3A.4.5-1: (SER Section 2.3A.4.5 – IP2 Auxiliary Feedwater Pump Room Fire Event)</u>

In LRA Section 2.3.4.5 the applicant describes systems not described elsewhere in the application credited for mitigating the consequences of a Unit 2 fire event in the auxiliary feedwater (AFW) pump room. Each system listed has an intended function of support safe shutdown in the event of a fire in the auxiliary feed pump room (10 CFR 50.48) in accordance with 10 CFR 54.4(a)(3). However, the applicant did not highlight the components or flowpaths needed to support this event on the license renewal drawings. In addition, the applicant did not identify and list the structures and components that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). Therefore, based upon the information provided in the LRA, the staff was not able to verify which components needed to perform the stated function are included within the scope of license renewal and are subject to an AMR.

By letter dated December 30, 2008, the staff requested the applicant to a) identify the system support function for the AFW pump room fire event, b) clearly identify the portions of the systems' flowpaths that support these functions that are subject to an AMR, and c) identify the portions of these flowpaths that are not already in scope for 10 CFR 54.4(a)(1) or (a)(2).

By letter dated January 27, 2009, the applicant explained that it has included the components required to support the safety function in the event of a fire in the AFW pump room within the scope of license renewal in accordance with 10 CFR 54.4(a)(3), and identified the passive long-lived components requiring an AMR in accordance with 10 CFR 54.21(a)(1). The closure of this item is documented in SER Section 2.3A.4.5.2.

OI 2.5-1: (SER Section 2.5.1 – Electrical and Instrumentation and Control Systems)

By letter dated November 16, 2007, the applicant responded to RAI 2.5-1 and revised LRA Figures 2.5-2 and 2.5-3, the "Offsite Power Scoping Diagram(s)" for IP2 and IP3, to address staff concerns regarding the IP2 and IP3 primary and secondary offsite power paths. By letter dated March 24, 2008, the applicant revised its response to RAI 2.5-1. In a subsequent letter dated August 14, 2008, the applicant further clarified its response to RAI 2.5-1.

At the time of issuance of the SER with Open Items, the staff was completing its review of the applicant's information on the SBO scoping boundary. As a result of its review, the staff identified a need for additional information, and by letter dated May 20, 2009, the staff requested the applicant to explain why certain components associated with the delayed access circuit were not included within the scope of license renewal. By letter dated June 12, 2009, the applicant provided additional information. The closure of this item is documented in SER Section 2.5.1.2.

OI 3.0.3.2.7-1: (SER Section 3.0.3.2.7 – Fire Protection Program)

During an audit, the staff reviewed program basis documents (for IP3) associated with the fire protection AMP. One of the basis documents states that 15 percent of the fire seals located in fire barriers are demonstrated to be operable by visual inspection on a frequency of 24 months. However, for those penetration seals that are inaccessible, the frequency of inspection is given as "not required." By letter dated April 29, 2008, the staff requested that the applicant justify the lack of visual inspections of inaccessible penetration seals.

In its response, dated May 28, 2008, the applicant stated that penetration seals are inspected at least once every seven operating cycles. However, IP3 site surveillance procedure provides provisions for cases where a penetration seal may become inaccessible for periodic inspection as result of plant configuration changes (i.e., installation of new plant equipment, walls, barriers, or other obstacles). In such cases, the IP3 site procedure includes guidance for the cessation of periodic surveillance of such penetration seals, subject to preparation of a formal fire protection engineering evaluation justifying the discontinuance of periodic visual surveillance.

As stated in the IP3 basis document, the visual inspection of inaccessible penetration seals is "not required" if justified by a supporting fire protection engineering evaluation, developed in accordance with the guidance of GL 86-10. On a case-by-case basis, the inaccessibility of any such penetration seal must be justified, and the fire protection adequacy of the configuration must be demonstrated. The evaluation, as stated in the basis document, must include assessment of proximate combustible loading, mitigating features, and the consequences of potential failure of the affected seal.

The staff reviewed the applicant's response and found that it did not address the fact that GL 86-10 evaluations exist for all inaccessible fire barrier penetration seals; the response only indicated that it is a part of the fire protection program to perform such analyses. The staff requested the applicant to confirm that these analyses do exist and are periodically reviewed and updated to ensure their continued applicability.

By letter January 27, 2009, the applicant stated that there are no IP3 fire barrier penetration seals excluded from periodic inspection due to inaccessibility. Therefore, there are no corresponding engineering evaluations. The closure of this item is documented in SER Section 3.0.3.2.7.

OI 3.0.3.2.15-1: (SER Section 3.0.3.2.15 – Structures Monitoring Program)

In response to Audit Item 359 regarding IP2 reactor cavity leakage into the containment, Entergy described the degraded conditions, summarized corrective actions taken, and identified the current status of the degradation. The reactor cavity at IP2 has a history of leakage at the upper elevations of the stainless steel cavity liner when flooded during refueling outages. Attempts have been made over the last several outages to mitigate this condition, with limited success. An action plan is being developed for a permanent fix to this issue. However, Entergy made no commitment for augmented inspection during the extended period of operation. In a follow-up discussion, the staff expressed its concern with regard to the potential for degradation of the underlying concrete and reinforcement rebar due to the leakage of borated water through the cavity liner and potential impact of the leakage on other adjacent structures. The staff requested Entergy to provide the technical basis as to why augmented inspection during the period of extended operation is not necessary, if the recurring leak condition is not permanently fixed.

In an August 14, 2008, supplemental response to the staff’s request, the applicant provided further information regarding the matter and committed to perform a one-time inspection and evaluation of a sample of potentially affected refueling cavity concrete, including embedded reinforcing steel, prior to the period of extended operation, in order to provide additional assurance that the concrete walls have not degraded (Commitment 36).

The staff has concluded that Entergy’s commitment to perform a one-time inspection and evaluation of a sample of potentially affected refueling cavity concrete, including embedded reinforcing steel, prior to the period of extended operation, is appropriate in order to assess the current state of the concrete and rebar. However, because the applicant does not plan to perform periodic inspections of the refueling cavity and affected area, the staff determined that for this structure/environment/aging effect combination, the LRA is not consistent with the GALL Report AMP. Additionally, the applicant’s program did not address concrete exposed to borated water.

By letter dated November 6, 2008, the applicant submitted a supplemental response to Audit Question 359, describing its plan for implementing a permanent fix over the next three (3) scheduled IP2 refueling outages (2010, 2012, and 2014). At the time of the issuance of the SER with Open Items, the staff was reviewing the applicant's response, pertinent to the effects of the refueling cavity leakage on the affected structures during the period of extended operation. As a result of the review, the staff identified the need for additional information, and by letters dated April 3, 2009 and May 20, 2009, the staff requested the applicant to provide additional information on the leakage path from the refueling cavity to the collection point lower in containment, and to explain how the structures monitoring program will adequately manage potential aging effects in this region during the period of extended operation. By letters dated May 1, 2009, and June 12, 2009, the applicant responded to the staff's request for additional information. The closure of this item is documented in the "Operating Experience" section of SER Section 3.0.3.2.15.

OI 3.0.3.2.15-2: (SER Section 3.0.3.2.15 – Structures Monitoring Program)

In response to Audit Item 360 regarding IP2 spent fuel pool (SFP) crack/leak paths, Entergy described the degraded conditions in greater detail, summarized corrective actions taken, and identified the current status of the degradation. The leakage was first discovered during excavation for the IP2 Fuel Storage Building in 2005. Entergy stated its belief that the conditions leading to this leakage have been corrected.

Entergy made no commitment for augmented inspection during the period of extended operation. Due to the lack of a leak-chase channel system at IP2 to monitor, detect and quantify potential leakage through the SFP liner, the staff was concerned that there has been insufficient time following the corrective actions to be certain that the leakage problems have been permanently corrected. In a follow-up discussion, the staff requested Entergy to provide the technical basis as to why augmented inspection during the extended period of operation is not necessary.

In an August 14, 2008, supplemental response to the staff's request, the applicant committed to test the groundwater outside the IP2 spent fuel pool for the presence of tritium from samples taken from adjacent monitoring wells, every 3 months (Commitment 25). The presence of tritium in the groundwater could be indicative of a continuing leak from the spent fuel pool.

Although Entergy has taken corrective action and has committed to quarterly monitoring for tritium in the groundwater, the staff was concerned that hidden degradation of concrete and rebar may have resulted from prior leakage, and may be continuing if there is still an active leakage mechanism. The staff requested the applicant to submit additional relevant information on the condition of concrete and rebar in areas where leakage was detected, and the design margins in these areas.

By letter dated November 6, 2008, the applicant submitted the requested information, which provides a detailed description of (1) the design margins for the spent fuel pool concrete walls; and (2) the results of prior concrete core sample testing and rebar corrosion testing. At the time of the issuance of the SER with Open Items, the staff was reviewing the applicant's response. As a result of its review, the staff identified the need for additional information. By letter dated April 3, 2009, the staff requested the applicant to explain how the Structures Monitoring Program will adequately manage potential aging effects in the inaccessible concrete of the IP2 spent fuel pool due to borated water leakage during the period of extended operation. By letter dated May 1, 2009, the applicant responded to the staff's request for additional information. The closure of this item is documented in the "Operating Experience" section of SER Section 3.0.3.2.15.

OI 3.0.3.3.2-1: (SER Section 3.0.3.3.2-1 – Containment Inservice Inspection Program)

In response to Audit Item 361 regarding areas of spalling of the exterior concrete containment, Entergy provided information about the areas and reasons for the spalling. The applicant stated that the spalls occur at locations where Cadweld sleeves have insufficient concrete cover, attributed to an original installation deficiency. Rusting is not active and spalls are in an area where the rebar stresses are low. Entergy indicated that Raytheon has evaluated the structural margins for the IP containments, and at the locations of the exposed rebar, there is sufficient margin to accommodate additional loss of material due to corrosion. The condition is being monitored under the containment inservice inspection program (CII-IWL). Entergy stated that remedial action will be taken if the spalls further degrade and affect structural integrity.

In an August 14, 2008 supplemental response to the staff's request, the applicant committed to enhance the CII-IWL inspections during the period of extended operation through enhanced characterization of the degradation (i.e., quantifying the dimensions of noted indications through the use of optical aids), and that this quantification will allow for more effective trending of degradation following future inspections (Commitment 37). However, since the degraded areas will remain exposed to the environment during the period of extended operation, the staff needed additional clarification of how Entergy plans to implement aging management during the period of extended operation.

The staff requested additional relevant information for the IP2 and IP3 containments on the design margins at the locations of observed degradation, identifying the specific locations and dimensions of the damage.

By letter dated November 6, 2008, the applicant submitted the requested information, describing the design margins for the IP containment structures at the locations of existing concrete degradation. At the time of the issuance of the SER with Open Items, the staff was reviewing the applicant's response. As a result of its review, the staff identified the need for additional information. By letter dated April 3, 2009, the staff requested the applicant to explain how the existing degradation and design margin will be considered in performing periodic inspections to monitor degradation that would ensure that there is no loss of containment intended function during the period of extended operation. By letter dated May 1, 2009, the applicant responded to the staff's request for additional information. The closure of this item is documented in the "Operating Experience" section of SER Section 3.0.3.3.2.

OI 3.0.3.3.3-1: (3.0.3.3.3 Heat Exchanger Monitoring Program)

LRA Section B.1.17 states that the minimum acceptable tube wall thickness for each heat exchanger inspected is based upon a component-specific engineering evaluation. Wall thickness is acceptable if greater than the minimum wall thickness for the component.

The applicant stated that the existing program will be enhanced to include the minimum wall thickness for the new heat exchangers added to the scope of the program, and to specify that if visual examination is performed, the acceptance criterion is "no unacceptable signs of degradation." The acceptance criteria for the eddy current tests based on minimum wall thicknesses are acceptable. However, the acceptance criteria for visual examination were not clear and appeared to be subjective. By letter dated December 30, 2008, the staff requested that Entergy define the visual inspection acceptance criteria.

By letter dated January 27, 2009, the applicant stated that visual inspections are performed on heat exchangers that cannot be inspected by quantitative non-destructive examination due to design limitations. The applicant further stated that visual inspection of external portions of heat exchanger tubes focuses on detecting the extent of tube erosion, vibration wear, corrosion, pitting, fouling, and scaling. Any unacceptable signs of degradation will be evaluated through the corrective action process. The closure of this item is documented in the “Acceptance Criteria” section of SER Section 3.0.3.3.3.

OI 3.0.3.3.4-1: (SER Section 3.0.3.3.4 Inservice Inspection Program)

The staff noted that the applicant indicated it plans to enhance the Inservice Inspection Program to provide for periodic visual inspections of lubrite sliding supports used in the SG supports and reactor coolant pump (RCP) supports in order to confirm the absence of aging effects. By letter dated December 30, 2008, the staff requested the applicant to establish and justify its selection of the inspection methods, inspections frequencies, sample sizes, and acceptance criteria that are applicable to the lubrite components, and the corrective actions that would be implemented if these acceptance criteria are exceeded.

By letter dated January 27, 2009, the applicant stated that the Inservice Inspection Program will be enhanced prior to the period of extended operation to include explicit provisions for periodic inspections of the lubrite sliding supports. The closure of this item is documented in the “Detection of Aging Effects” section of SER Section 3.0.3.3.4.

OI 3.0.3.3.4-2: (SER Section 3.0.3.3.4 Inservice Inspection Program)

The staff noted that the “corrective actions” program element for AMP B.1.18, Inservice Inspection Program, credits only the corrective actions in the ASME Code, Section XI, Articles IWA-4000 and IWA-7000 as the corrective action criteria for the program. The ASME Code, Section XI editions of record for IP are the 2001 Edition of the ASME Code, Section XI inclusive of the 2003 Addenda for IP2 and the 1989 Edition of the ASME Code, Section XI, with no addenda for IP3. The staff noted that Entergy did not credit component-specific corrective action criteria in ASME Section XI, Article IWB-4000/7000 for Class 1 components, Article IWC-4000/7000 for Class 2 components, Article IWD-4000/7000 Class 3 components, or Article IWF-4000/7000 for ASME Code Class component supports as being within the scope of the “corrective action” program element for this AMP. By letter dated December 30, 2008, the staff asked the applicant to clarify whether the content of the “corrective actions” program element was intended to mean that Entergy will implement the corrective action provisions in the ASME Code, Section XI, Subsections IWA, IWB, IWC, IWD, and IWF that are applicable to the component Code Class in the applicable ASME Code, Section XI code of record.

By letter dated January 27, 2009, the applicant stated that it will implement the corrective action provisions in the ASME Code, Section XI, Subsections IWA, IWB, IWC, IWD, and IWF that are applicable to the component Code Class in the applicable ASME Code, Section XI edition of record. The closure of this item is documented in the “Corrective Actions” section of SER Section 3.0.3.3.4.

OI 3.0.3.3.7-1: (SER Section 3.0.3.3.7 – Periodic Surveillance and Preventive Maintenance)

In LRA Appendix B, Section B.1.29, the applicant describes the existing Periodic Surveillance and Preventive Maintenance Program as an existing, plant-specific program. The staff reviewed the applicant's program using the review criteria and guidance in the SRP-LR, Appendix. During its review, the staff determined that additional information regarding certain program elements was needed. By letter dated December 30, 2008, the staff issued an RAI to obtain information in the following areas:

1. The "scope of program" program element for the Periodic Surveillance and Preventive Maintenance Program did not specify which components were within the scope of the program.

2. The applicant appeared to be crediting visual examinations, in part, to manage cracking but did not identify the visual techniques to be used.

3. The "monitoring and trending" program element discussion only mentioned that the activities within the scope of the AMP provided for adequate monitoring and trending; there was no discussion on how the data from the inspections performed under the "detection of aging effects" program element would be collected, quantified, or evaluated against applicable acceptance criteria, and used to make predictions related to degradation growth or to schedule re-inspections of the components.

4. For the majority of the elastomeric or polymeric components within the scope of the AMP, the applicant credited both visual examinations and manual flexing of the components to manage changes in material properties of these elastomeric or polymeric components. However, material properties are intrinsic thermodynamic properties that cannot be monitored by direct visual or NDE inspection methods, and changes in material properties (such as loss of fracture toughness, hardening, or increases or reductions in strength) are more appropriately managed through appropriate material property analyses (including destructive analyses) or though performance of physical tests (such as flexing, etc.) that could provide some indication of whether the material properties for the components were changing.

5. Certain statements regarding "operating experience" were ambiguous in that the applicant did not indicate clearly whether aging had been detected but that the amount of aging was determined to be acceptable when compared to the acceptance criteria for the aging effect, or whether the inspections did not identify the presence of aging effects in the components being inspected.

By letter dated January 27, 2009, the applicant responded to the staff's request for additional information. The closure of this item is documented in SER Section 3.0.3.3.7.

OI 3.1.2-1: (SER 3.1.2.1.3 Cracking Due to Cycling Loading, Stress Corrosion Cracking, and Primary Water Stress Corrosion Cracking)

During its review of the nickel alloy components and the Nickel Alloy Program, the staff determined that for some component types, the applicant: (1) did not indicate which base metal is used at IP (i.e., Alloy 600); (2) did not include any AMR entries for reactor vessel bottom head drains; and (3) did not credit the Inservice Inspection Program to manage cracking in steam generator primary nozzle closure rings. By letter dated December 30, 2008, the staff requested the applicant to:

Part A - Clarify whether the following components at IP2 or IP3 are fabricated from Alloy 600 base metal materials or welded with Alloy 182 or Alloy 82 filler metal materials: (1) control rod drive (CRD) housing-CRD nozzle welds, (2) upper reactor vessel closure head (RVCH) head vent nozzle-to-RVCH welds, and (3) CRD housing penetration core exit thermocouple nozzle assembly (CETNA^{TM}) components.

Part B - The staff notes that in the applicant's response to Audit Item 208, dated December 18, 2007, the applicant stated that the LRA Tables 3.1.2-1-IP2 through 3.1.2-4-IP2 and LRA Tables 3.1.2-1-IP3 through 3.1.2-4-IP3 include numerous AMR items for nickel-alloy components. The applicant stated that these AMR items are compared to GALL Report Items IV.A2-18 and IV.A2-19, which correspond to LRA table entries 3.1.1-31 and 3.1.1-65. The applicant stated that the AMR in LRA AMR 3.1.1-69 is only for management of cracking in the RV inlet and outlet nozzle safe-ends and the RV bottom head drain safe-ends. With respect to the AMRs on cracking of nickel alloy bottom mounted instrumentation (BMI) nozzle components, the staff notes that the response to Audit Item 208 stated that the RV bottom head safe-ends at IP2 and IP3 are those for the RV bottom head drains, but LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3 do not include any AMR entries for RV bottom head drains. The staff requested the applicant to provide its basis on whether LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3 need to be amended to include new AMRs for RV bottom head drains and their associated drain-to-bottom head welds, and if so to clarify whether the bottom head drains are fabricated from Alloy 600 base metal materials or are welded to the bottom RV heads using Alloy 82 or 182 nickel alloy filler metal materials.

Part C - AMRs of LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3, which pertain to the management of cracking in the steam generator (SG) primary nozzle closure rings, credit only the Water Chemistry Control Program to manage cracking of the components. GALL Report Table IV.D1, Line Item D1-1 for these components recommends, in part, that the Inservice Inspection Program be credited for aging management of this effect in addition to Water Chemistry Control Program – Primary and Secondary. Given the information requested in Part A above, the staff requested the applicant to provide a basis for why the AMRs on cracking of the nickel alloy SG primary nozzle closure rings were aligned to GALL AMR Table VI.D1, Line Item D1-6, and why the Inservice Inspection Program is not also credited.

By letter dated January 27, 2009, the applicant responded to the staff's request for additional information. The closure of this item is documented in SER Sections 3.0.3.3.5, 3.1.2.1.3, 3.1.2.2.13, and 3.1.2.2.16.

OI 3.1.2.2.7-1: (SER Section 3.1.2.2.7 - Cracking Due to Stress Corrosion Cracking)

The Inservice Inspection Program is a plant-specific condition monitoring program for the management of cracking in ASME Code Class 1 components, including ASME Code Class 1 cast austenitic stainless steel (CASS) components. However, the staff noted that the inspections credited under this program might be either ultrasonic test (UT) examinations or enhanced VT-1 visual examinations. The staff also noted that the applicant's program includes a flaw evaluation methodology for CASS components that are susceptible to thermal aging embrittlement.

By letter dated December 30, 2008, the staff asked the applicant to (a) clarify how current state of the art UT methods, as implemented through the Inservice Inspection Program or other programs, would be adequate to detect cracks in CASS materials, and (b) justify its basis for crediting the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program to manage and detect for cracking in the CASS pressurizer spray heads at IP2 and IP3.

By letter dated January 27, 2009, the applicant stated that because current volumetric examination methods are not adequate for reliable detection and evaluation of cracking in CASS components, ultrasonic testing examinations are not credited for use in aging management of reduction of fracture toughness in CASS components at Indian Point. Entergy also stated that listing the Thermal Aging Embrittlement of CASS Program on the line item for cracking may be unnecessary, but was included to demonstrate consistency with NUREG-1801 Item IV.C-3, which recommends a plant-specific program to address thermal aging embrittlement. The closure of this item is documented in SER Section 3.1.2.2.7.

OI 3.3-1: (SER Section 3.3A.2.3.1 – Service Water System - Summary of Aging Management Review – LRA Table 3.3.2-2-IP2)

The staff reviewed LRA Table 3.3.2-2-IP2, which summarizes the results of AMR evaluations for the service water system component groups. The LRA table referenced Note F for titanium heat exchanger shell externally exposed to condensation with no aging effect and no AMP. The staff noted that in LRA Table 3.3.2-9-IP2, the applicant used Note F for the same material/environment combination, but cited an aging effect of loss of material and stated that it will be managed by the Periodic Surveillance and Preventive Maintenance Program. This appears to be a discrepancy.

Similarly, the staff reviewed LRA Table 3.3.2-14-IP2, which summarizes the results of AMR evaluations for the emergency diesel generator system component groups. The LRA table referenced Note F for titanium heat exchanger tubes exposed to raw water (internal) having aging effects of fouling and loss of material which will be managed using the Service Water Integrity Program. The staff noted that in LRA Table 3.3.2-2-IP2, the applicant used Note F for the same material/environment combination but cites cracking as an additional aging effect. This appears to be a discrepancy.

The staff indicated that further information was required regarding the apparent discrepancies, before this item may be closed.

By letter dated January 27, 2009, the applicant stated that LRA Table 3.3.2-2-IP2 contains correct AMR results for the titanium heat exchanger shell externally exposed to condensation with no aging effect and no AMP, and that LRA Table 3.3.2-9-IP2 has been corrected. In addition, the applicant stated that the reason for the difference between cited aging effects in LRA Tables 3.3.2-14-IP2 and Table 3.3.2-2-IP2 is the difference between the grades of titanium used. In LRA Table 3.3.2-2-IP2, the grade of titanium installed in the service water system is unknown so it was conservatively assumed that the material was not grades 1, 2, 7, 11 or 12 and therefore, cracking was identified as an aging effect requiring management. The closure of this item is documented in SER Sections 3.3A.2.3.1 and 3.3A.2.3.11.

OI 3.4-1: (SER Section 3.4.2.1.9 – Auxiliary Feedwater Pump Room Fire Event)

In LRA Section 3.4.2, the applicant states that:

> The components in the systems required to supply feedwater to the steam

> generators during the short duration of the fire event are in service at the time the event occurs or their availability is checked daily. Therefore, integrity of the systems and components required to perform post-fire intended functions for at least one hour is continuously confirmed by normal plant operation. During the event these systems and components must continue to perform their intended functions to supply feedwater to the steam generators for a minimum of one hour. Significant degradation that could threaten the performance of the intended functions will be apparent in the period immediately preceding the event and corrective action will be required to sustain continued operation. For the minimal one hour period that these systems would be required to provide make up to the steam generators, further aging degradation that would not have been apparent prior to the event is negligible. Therefore, no aging effects are identified, and no Summary of Aging Management Review table is provided.

Because these systems contain passive, long-lived components, the applicant must demonstrate 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. Based on the information contained in the LRA, Entergy did not appear to have demonstrated that the effects of aging for passive, long-lived components within the systems credited for providing flow to the steam generators during the fire event will be adequately managed.

By letter dated December 30, 2008, the staff issued an RAI to request that the applicant provide a list of passive, long-lived component types, material, environment, and aging effect combinations, and the programs that will be used to manage the aging effects for these SCs.

By letter dated January 27, 2009, the applicant responded to the staff's RAI and provided AMR results for the passive, long-lived components within the systems credited for providing flow to the steam generators during the fire event. For all component types, the applicant listed the aging effects and AMP as "none." The staff reviewed the response and determined that the systems contain passive, long-lived components made of materials that when exposed to the stated environments may experience aging effects, which must be managed during the period of extended operation in accordance with 10 CFR 54.21(a)(3).

By letter dated May 1, 2009, Entergy submitted a clarification response to RAI 3.4.2-1 as well as a new commitment to install a fixed automatic fire suppression system for IP2 in the AFW pump room prior to entering the period of extended operation. Entergy stated that this commitment will delete the requirement for IP2 to place reliance on certain portions of the secondary plant systems for alternate secondary heat sink measures to cope with potential AFW Pump Room fire scenarios.

The staff determined that because the planned installation is not yet part of the current licensing basis, it cannot make a finding consistent with the requirement in 10 CFR 54.29(a). Therefore, by letter dated May 20, 2009, the staff requested that the applicant provide information to demonstrate that the effects of aging will be adequately managed so that the intended function(s) will maintained consistent with the current licensing basis for the period of extended operation as required by 10 CFR 54.21(a)(3).

By letter dated June 12, 2009, the applicant responded to the staff's request and provided revised tables which include aging effects and AMPs to manage the aging effects for the component types that support the AFW pump room fire event that were not already included in scope and subject to aging management review for 10 CFR 54.4(a)(1) or (a)(2). The closure of this item is documented in SER Section 3.4A.2.9

OI 3.5-1: (SER Section 3.5.2.2.1 – Containment Structures)

In LRA Sections 3.5.2.2.1.1 and 3.5.2.2.2.1, the applicant referenced an inconsistent combination of air entrainment and water-cement ratios. Per American Concrete Institute (ACI) 318-63, the water-cement ratio may be as high as 0.576 if there is no air entrainment. With air entrainment of four to six percent, the maximum water-cement should be 0.465. The staff asked the applicant to clarify if the correct value should be 0.465, and also to substantiate how it meets the code of record (i.e., ACI 318-63).

By letter dated November 6, 2008, the applicant stated that ACI 318-63 provides two methods for determination of concrete properties which will result in the required concrete strength. The applicant further stated that the concrete mixture at IP was established based on tests of concrete mixtures and actual tests for containment concrete showed compressive strengths above the required 20.7 MPa (3000 psi). In the SER with Open Items, the staff stated that it was reviewing the applicant's response, and that its evaluation of this matter would be included in the final SER.

The staff also noted that the applicant states in the LRA that the concrete also meets the requirements of a later ACI guide, ACI 201.2R-77. The staff asked the applicant to clarify the use of the later ACI 201.2R-77, since the editions of the ASTM standards may have changed between 1963 and 1977. In its letter dated November 6, 2008, the applicant stated that IP structures designed in accordance with ACI 318-63 align with many of the recommendations in ACI 201.2R-77. At the time of the issuance of the SER with Open Items, the staff was reviewing the applicant's response. As a result of the review, the staff identified the need for additional information. By letter dated April 3, 2009, the staff asked the applicant to describe the methodology used to establish the required concrete compressive strength of 3000 psi for the containment and other safety-related concrete structures, in accordance with ACI 318- 63, Method 2. By letter dated May 1, 2009, the applicant responded to the staff's request for additional information. The closure of this item is documented in SER Section 3.5.2.2.1.

OI 3.5-2: (SER Section 3.5.2.2.1, Subsection entitled "Reduction of Strength and Modulus of Concrete Structures Due to Elevated Temperature")

In LRA Section 3.5.2.2.1.3, the applicant stated that ACI 349 specifies long-term temperature limits of 66°C (150 °F) for general areas and 93°C (200 °F) for local areas. The effects of aging due to elevated temperature exposure are not significant below these temperatures.

The applicant also stated that the IP2 containment areas during normal operation are below 54°C (130 °F) bulk average temperature. Penetrations through the containment cylinder wall for pipes carrying hot fluid are cooled by air-to-air heat exchangers and the pipes are insulated to maintain the temperature in the adjoining concrete below 121°C (250 °F). The GALL Report provides for local area concrete temperatures higher than 93°C (200 °F) if tests or calculations evaluate the reduction in strength. The applicant also states that an evaluation of IP2 hot piping penetration concrete has found temperatures up to 121°C (250 °F) acceptable.

The applicant further stated that the IP3 containment areas normally operate below a bulk average temperature of 54°C (130 °F). Penetrations through the containment cylinder wall for pipes carrying hot fluid are cooled by air-to-air heat exchangers and the pipes are insulated to maintain the temperature in the adjoining concrete below 93°C (200 °F).

The applicant concluded that these are not aging effects requiring management for IP.

In SRP-LR Section 3.5.3.2.1.3, it is stated that the GALL Report recommends further evaluation of programs to manage reduction of strength and modulus of concrete structures due to elevated temperature for PWR and BWR concrete and steel containments. The GALL Report notes that the implementation of ASME Section XI, Subsection IWL examinations and 10 CFR 50.55a would not be able to detect the reduction of concrete strength and modulus due to elevated temperature and also notes that no mandated aging management exists for managing this aging effect. The GALL Report recommends that a plant-specific evaluation be performed if any portion of the concrete containment components exceeds specified temperature limits, i.e., general temperature greater than 66°C (150 °F) and local area temperature greater than 93°C (200 °F).

The staff's review of operating experience did not identify any occurrences of concrete degradation at the IP2 hot penetrations. However, because concrete degradation at elevated temperatures is a slow process, there is a need to confirm that an additional 20 years of operation will not lead to significant degradation. The staff asked the applicant what the effects on the concrete will be during the period of extended operation for areas where the local temperature exceeds 93°C (200 °F). By letter dated November 6, 2008, the applicant stated that an engineering evaluation of the effect of 121°C (250 °F) temperatures on the hot piping penetration concrete was performed. The evaluation determined that a reduction in strength of 15 percent could be expected from the elevated temperatures. The applicant further stated that this reduction in strength was acceptable since the original concrete compressive strength tests showed an actual strength more than 15 percent greater than the design strength of 20.7 MPa (3000 psi).

At the time of the issuance of the SER with Open Items, the staff was reviewing the applicant's response. As a result of its review, the staff identified the need for additional information. By letter dated April 3, 2009, the staff requested the applicant to clearly explain the role of the air-to-air heat exchangers in cooling the concrete around the hot piping penetrations. In addition the staff asked the applicant to describe the methodology used to arrive at the conclusion that the actual concrete strength is more than 15 percent greater than 20.7 MPa (3000 psi), i.e., greater than 23.8 MPa (3450 psi), to provide a summary of the results, and to explain how consideration was given to the reduction in modulus of elasticity in the high temperature concrete evaluation. By letter dated May 1, 2009, the applicant responded to the staff's request for additional information. The closure of this item is documented in SER Section 3.5.2.2.1.

OI 3.5-3: (SER Section 3.5.2.2.2 – Safety-Related and Other Structures and Component Supports)

Item 3.5.1-40 of LRA Table 3.5.1 addresses building concrete at locations of expansion and grouted anchors for the aging effect of reduction in concrete anchor capacity due to local concrete degradation/service-induced cracking or other concrete aging mechanisms. The GALL Report recommends the Structures Monitoring Program (SMP) for monitoring this concrete component for the stated aging effect. In the SER with Open Items, the staff found that the applicant had appropriately credited the SMP for Groups B2 through B5 component supports and surrounding concrete consistent with the GALL Report. However, for the Group B1 (ASME

Class 1, 2, 3 & MC) supports, the applicant's reference to "IP concrete anchors and surrounding concrete" implies that the applicant is crediting the ISI-IWF AMP for both the supports and surrounding concrete. The staff found that, while ISI-IWF is appropriate for the Group B1 component supports themselves, ISI-IWF is not specifically applicable for concrete surrounding the anchors for these supports, because the code support boundary definition which extends to the surface of the building but does not include the building structure. Therefore, the staff indicated that the applicant should indicate which AMP it will use to manage the effects of aging for the concrete surrounding the B1 supports.

By letter dated January 27, 2009, the applicant stated that the applicable aging management program for concrete surrounding concrete anchors is the Structures Monitoring Program. The applicant also clarified the statement in LRA Section 3.5.2.2.2.6(1). The closure of this item is documented in SER Section 3.5.2.2.2.

OI 4.3-1: (SER Section 4.3.1 – Class 1 Fatigue)

In its review, the staff noted that the applicant used data from 1973 to 1995 to project the number of plant heatups and cooldowns from 1995 to March 31, 2006 (current cycles), rather than use actual data. As stated above, the applicant will track the number of transients under the Fatigue Monitoring Program. However, without the actual number of heatups and cooldowns from 1995 to March 31, 2006, the applicant may not be able to accurately predict when the number of analyzed cycles might be exceeded. The staff notes that changes in operating practices such as refueling (12-month refueling cycle vs. 24-month refueling cycle) would decrease the number of heatups and cooldowns experienced post 1995, which should yield a more conservative projection. Nonetheless, the applicant should have the actual data for the plant startups and shutdowns during this period of time. Therefore, the staff believes that the use of actual plant operating experience in lieu of a projection for the current number of cycles is appropriate.

By letter dated January 27, 2009, the applicant provided the actual number of cycles for IP3 plant heatups and cooldowns through March 31, 2006. This information was also provided in response to Audit Item 14. The closure of this item is documented in the "Staff Evaluation" section of SER Section 4.3.1.

1.6 Summary of Proposed License Conditions

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

The first license condition requires the applicant to include the UFSAR supplement required by 10 CFR 54.21(d) in the first UFSAR update required by 10 CFR 50.71(e) following the issuance of the renewed licenses.

The second license condition requires future activities described in the UFSAR supplement to be completed prior to the period of extended operation.

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

SECTION 2

STRUCTURES AND COMPONENTS SUBJECT TO AGING MANAGEMENT REVIEW

2.1 Scoping and Screening Methodology

2.1.1 Introduction

Title 10 of the *Code of Federal Regulations* (10 CFR) 54.21, “Contents of Application—Technical Information,” requires for each license renewal application (LRA) an integrated plant assessment (IPA) listing those structures and components (SCs) subject to an aging management review (AMR) for all of the systems, structures, and components (SSCs) within the scope of license renewal.

LRA Section 2.1, “Scoping and Screening Methodology,” describes the methodology for identifying those SSCs at the Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3) that are within the scope of license renewal and those SCs that are subject to an AMR. The staff reviewed the scoping and screening methodology of Entergy Nuclear Operations, Inc. (Entergy or the applicant), to determine whether it meets the scoping requirements of 10 CFR 54.4(a) and the screening requirements of 10 CFR 54.21.

In developing the scoping and screening methodology for the LRA, the applicant considered the requirements of 10 CFR Part 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants” (the Rule), Statements of Consideration for the Rule, and the guidance of Nuclear Energy Institute (NEI) 95-10, Revision 6, “Industry Guideline for Implementing the Requirements of 10 CFR Part 54—The License Renewal Rule,” issued June 2005. The applicant also considered the correspondence between the U.S. Nuclear Regulatory Commission (NRC) staff, other applicants, and NEI.

2.1.2 Summary of Technical Information in the Application

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

In LRA Section 2.1, the applicant described the process to identify the SSCs that meet the license renewal scoping criteria of 10 CFR 54.4(a) and the process used to identify the SCs that are subject to an AMR, as required by 10 CFR 54.21(a)(1). Additionally, LRA Section 2.2, “Plant Level Scoping Results,” Section 2.3, “Scoping and Screening Results: Mechanical Systems,” Section 2.4, “Scoping and Screening Results: Structures,” and Section 2.5, “Scoping and Screening Results: Electrical and Instrumentation and Control Systems,” provide the results of the process used to identify the SCs that are subject to an AMR. LRA Section 3.0, “Aging Management Review Results,” presents information regarding the IP2 and IP3 AMR process in Section 3.1, “Reactor Vessel, Internals and Reactor Coolant System,” Section 3.2, “Engineered Safety Features Systems,” Section 3.3, “Auxiliary Systems,” Section 3.4, “Steam and Power Conversion Systems,” Section 3.5, “Structures and Component Supports,” and Section 3.6, “Electrical and Instrumentation and Controls.” Section 4.0 of the LRA, “Time-Limited Aging Analyses,” contains the applicant’s identification and evaluation of time-limited aging analyses (TLAAs).

2.1.3 Scoping and Screening Program Review

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

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

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

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

In addition, the staff conducted a scoping and screening methodology audit at IP2 and IP3, located outside Buchanan, NY, during the week of October 8–12, 2007. The audit focused on ensuring that the applicant had developed and implemented adequate guidance to conduct the scoping and screening of SSCs in accordance with the methodologies described in the LRA and the requirements of the Rule. The staff reviewed implementation of the project-level guidelines and topical reports describing the applicant’s scoping and screening methodology. The staff conducted detailed discussions with the applicant on the implementation and control of the license renewal program and reviewed the administrative control documentation used by the applicant during the scoping and screening process, the quality practices used by the applicant to develop the LRA, and the training and qualification of the LRA development team. The staff evaluated the quality attributes of the applicant’s Aging Management Program activities described in Appendix A, “Updated Final Safety Analysis Report Supplement,” and Appendix B, “Aging Management Programs and Activities,” to the LRA. On a sampling basis, the staff performed a system review of the service water (SW) system and the turbine building, including a review of the scoping and screening results reports and the supporting design documentation used to develop the reports, to ensure that the applicant had appropriately implemented the methodology outlined in the administrative controls and to verify that the results are consistent with the current licensing basis (CLB) documentation.

2.1.3.1 Implementing Procedures and Documentation Sources for Scoping and Screening

The staff reviewed the applicant's scoping and screening implementing procedures as documented in the Scoping and Screening Methodology Audit Trip Report (Agencywide Documents Access and Management System [ADAMS] Accession No. ML083540648) to verify that the process for identifying SCs subject to an AMR was consistent with the SRP-LR. Additionally, the staff reviewed the scope of CLB documentation sources and the process used by the applicant to ensure that the applicant's commitments, as documented in the CLB and relative to the requirements of 10 CFR 54.4 and 10 CFR 54.21, were appropriately considered and that the applicant adequately implemented its procedural guidance during the scoping and screening process.

2.1.3.1.1 Summary of Technical Information in the Application

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

- updated final safety analysis reports (UFSARs)
- technical specifications and bases
- technical requirements manual
- design-basis documents (DBDs)
- licensing commitment database
- Maintenance Rule bases documents
- fire hazards analysis
- Appendix R safe-shutdown analysis
- station blackout (SBO) analysis
- SERs
- docketed correspondence
- plant drawings

The applicant stated that it used this information to identify the functions performed by plant systems and structures. It then compared these functions to the scoping criteria in 10 CFR 54(a)(1)–(3) to determine whether the associated plant system or structure performed a license renewal intended function. It also used these sources to develop the list of SCs subject to an AMR.

2.1.3.1.2 Staff Evaluation

Scoping and Screening Implementation Procedures. The staff reviewed the applicant's scoping and screening methodology implementation procedures, including license renewal guidelines, documents, reports, and AMR reports, as documented in the audit report, to ensure that the guidance is consistent with the requirements of the Rule, the SRP-LR, and NEI 95-10. The staff finds that the overall process used to implement the 10 CFR Part 54 requirements described in the implementing documents and AMRs is consistent with the Rule, the SRP-LR, and industry guidance. The applicant's implementing documents contain guidance for determining plant SSCs within the scope of the Rule and for determining which SCs within the scope of license renewal are subject to an AMR (see ADAMS Accession No. ML080730399). During the review of the implementing documents, the staff focused on the consistency of the detailed procedural guidance with information in the LRA, including the implementation of staff positions documented in the SRP-LR, and the information in responses, dated February 13, 2008, to the staff's requests for additional information (RAIs).

After reviewing the LRA and supporting documentation, the staff determined that the scoping and screening methodology instructions are consistent with the methodology description provided in LRA Section 2.1. The applicant described its methodology in sufficient detail to provide concise guidance on the scoping and screening implementation process to be followed during the LRA activities.

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

During the audit, the staff reviewed pertinent information sources used by the applicant including the UFSARs, license renewal boundary diagrams, and Maintenance Rule information. In addition, the applicant's license renewal process identified additional potential sources of plant information pertinent to the scoping and screening process, including the equipment database, system safety function sheets, safety classification documents, design-basis references, piping and instrumentation diagrams (P&IDs), electrical drawings, docketed correspondence, technical specifications and bases, the fire hazards analysis, and safety evaluations. The staff confirmed that the applicant's detailed license renewal program guidelines specify the use of the CLB source information in developing scoping evaluations.

The IP2 and IP3 equipment database and the system safety function sheets are the applicant's primary repository for component safety classification information. During the audit, the staff reviewed the applicant's administrative controls for the IP2 and IP3 equipment database, the system safety function sheets, and safety classification data. Plant administrative procedures describe these controls and govern their implementation. Based on a review of the administrative controls and a sample of the safety classification information contained in the IP2 and IP3 equipment database and system safety function sheets, the staff concludes that the applicant established adequate measures to control the integrity and reliability of IP2 and IP3 safety classification data and, therefore, the IP2 and IP3 equipment database and system safety function sheets provide a sufficiently controlled source of system and component data to support scoping and screening evaluations.

During the staff's review of the applicant's CLB evaluation process, the applicant explained the incorporation of updates to the CLB and the process used to ensure that those updates are adequately incorporated into the license renewal process. The staff determined that LRA Section 2.1 describes the CLB and related documents used during the scoping and screening process consistently with the guidance contained in the SRP-LR.

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

2.1.3.1.3 Conclusion

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

2.1.3.2 Quality Controls Applied to the Development of the License Renewal Application

2.1.3.2.1 Staff Evaluation

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

- The applicant developed written plans and procedures to direct implementation of the scoping and screening methodology, control LRA development, and describe training requirements and documentation.
- The applicant developed written requirements for developing, revising, and approving the guidelines and procedures.
- The applicant considered pertinent issues in previous LRAs and corresponding RAIs to determine their relevance to the IP2 and IP3 application.
- Industry peers and the site review committee examined the LRA before its submittal to the staff.

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

2.1.3.3 Training

2.1.3.3.1 Staff Evaluation

The staff reviewed the applicant's training process for consistent and appropriate guidelines and methodology for the scoping and screening activities. As outlined in the implementing documents, the applicant requires training and documentation for all personnel participating in the LRA development. Personnel are required to complete the training before preparing and approving implementing procedures. Training materials include the applicant's project guidelines; pertinent industry documents; 10 CFR Part 54 and its Statements of Consideration; NEI 95-10, Revision 6; Regulatory Guide 1.188, Revision 1, "Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses," issued September 2005; SRP-LR; NUREG-1801, Revision 1, "Generic Aging Lessons Learned (GALL) Report" (hereafter referred to as the GALL Report); and attendance at a license renewal orientation session.

The applicant's procedures specify two levels of training—(1) training for the corporate project team personnel and (2) training for site personnel. Generally, the project team personnel review all training documents in order to identify those documents directly related to their specific scoping and screening responsibilities. The intent of the training for site personnel is to ensure that personnel understand the license renewal process and the materials specifically related to each individual's license renewal responsibilities. Completion of the training allows site personnel to evaluate and approve the license renewal documents for technical accuracy. Qualification and training records and a checklist serve as documentation for each individual's completed license renewal training. The staff reviewed completed qualification and training records and the completed checklists for several of the applicant's license renewal personnel. Additionally, after discussions with the applicant's license renewal personnel during the audit, the staff verified that the applicant's personnel are knowledgeable about the license renewal process requirements and specific technical issues within their areas of responsibility.

2.1.3.3.2 Conclusion

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

2.1.3.4 Conclusion of Scoping and Screening Program Review

On the basis of a review of information provided in LRA Section 2.1, a review of the applicant's detailed scoping and screening implementing procedures, discussions with the applicant's license renewal personnel, and the results from the scoping and screening 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 Scoping Methodology for Plant Systems, Structures, and Components

In LRA Section 2.1, the applicant described the methodology used to scope SSCs under the 10 CFR 54.4(a) scoping criteria. The applicant described the scoping process for the plant in terms of systems and structures. Specifically, the scoping process consisted of developing a list of plant systems and structures, identifying their intended functions, and determining which functions meet one or more of the three criteria detailed in 10 CFR 54.4(a). The applicant developed the list of systems using the equipment database; the list of plant structures was developed from a review of plant layout drawings, Maintenance Rule documentation, DBDs, and the UFSARs. Mechanical system functions were identified from the IP2 and IP3 safety system function sheets (SSFSs). The applicant obtained additional information on mechanical system functions from the UFSARs, the Maintenance Rule documents, piping flow diagrams, and

DBDs. Structural functions were identified using the UFSARs, the Maintenance Rule basis documents for structures, the fire hazards analyses, DBDs, and structural drawings. According to the LRA, all electrical and instrumentation and control (I&C) systems, and electrical and I&C components in mechanical systems, are within the scope of license renewal.

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

2.1.4.1.1 Summary of Technical Information in the Application

LRA Section 2.1.1.1, "Application of Safety-Related Scoping Criteria," describes the scoping methodology as it relates to the safety-related criterion in accordance with 10 CFR 54.4(a)(1). With respect to the safety-related criterion, the applicant stated that safety-related system and structure functions are initially identified through a review of the SSFSs and then confirmed by a review of the UFSARs, Maintenance Rule documents, piping flow diagrams, and DBDs, as applicable. Systems and structures whose intended functions meet one or more of the criteria in 10 CFR 54.4(a)(1) were included within the scope of license renewal. The applicant confirmed that it considered all plant conditions, including conditions of normal operation, design-basis accidents (DBAs), external events, and natural phenomena for which the plant must be designed, for license renewal scoping under the 10 CFR 54.4(a)(1) criteria.

2.1.4.1.2 Staff Evaluation

Pursuant to 10 CFR 54.4(a)(1), the applicant must consider all safety-related SSCs relied on to remain functional during and following a design-basis event (DBE) to ensure the performance of certain functions. These functions are (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 described in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11, "Determination of Exclusion Area, Low Population Zone, and Population Center Distance."

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

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

During the audit, the applicant stated that it evaluated the types of events listed in NEI 95-10 (i.e., anticipated operational occurrences, DBAs, external events, and natural phenomena) that were applicable to IP2 and IP3. The applicant identified the documents (the UFSARs and the fire hazards analysis) that described the events. The applicant also reviewed licensing correspondence and DBDs. The staff determined that the applicant's evaluation of DBEs is consistent with the SRP-LR.

The applicant performed scoping of SSCs for the 10 CFR 54.4(a)(1) criterion in accordance with the license renewal implementing documents, 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 documents 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 those written instructions. 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). The IP2 and IP3 CLB definition of "safety-related" meets the definition in 10 CFR 54.4(a)(1). LRA Section 2.1.1.1 documents the applicant's definition of safety-related and exceptions to the definition in 10 CFR 54.4(a)(1). Based on its review, the staff confirmed that the applicant correctly identified the applicable dose criteria for IP2 and IP3 as set forth in 10 CFR 54.4(a)(1)(iii). The dose criteria are set forth in 10 CFR 50.67(b)(2) and 10 CFR 100.11 for IP2, as reflected in the LRA. Although the IP3 CLB definition of "safety-related" did not explicitly include reference to 10 CFR 50.67(b)(2), the requirements of 10 CFR 50.67(b)(2), which concern the use of an alternate source term in the dose analysis, are also applicable to IP3, which has been approved for the use of an alternate source term. The staff confirmed that the applicant reviewed the IP3 systems and components credited in the plant's dose analyses to ensure that the applicable systems and components were included in the scope of the license renewal. The applicant did not identify any additional SSC functional requirements, beyond those established to meet the requirements of 10 CFR Part 100, "Reactor Site Criteria," credited for the application of the alternate source term, and no additional SSCs for IP3 were required for inclusion in the scope of license renewal under 10 CFR 50.67(b)(2).

The staff reviewed a sample of the license renewal scoping results for the SW system and the turbine building to provide additional assurance that the applicant adequately implemented its scoping methodology in accordance with 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.

In order to verify that the applicant identified and used pertinent engineering and licensing information to identify the SSCs required by 10 CFR 54.4(a)(1) to be within the scope of license renewal, the staff determined that it would require additional information to complete its review of the applicant's scoping methodology.

In RAI 2.1-1(c), dated January 14, 2008, the staff stated that during the audit, it reviewed the applicant's technical evaluation and onsite documentation for nonsafety-related SSCs affecting safety-related SSCs, which indicate that certain similar SSCs were included within the scope of license renewal under 10 CFR 54.4(a)(1) for one unit, but under 10 CFR 54.4(a)(2) for the other unit. The staff requested that the applicant provide the rationale and basis for including similar SSCs within the scope of license renewal under 10 CFR 54.4(a)(1) for one unit, but under 10 CFR 54.4(a)(2) for the other unit, and describe how it performed the corresponding review of the adjacent or attached nonsafety-related SSCs (for inclusion within the scope of license renewal) for similar systems in the two units. In its February 13, 2008, response to RAI 2.1-1(c), the applicant stated the following:

Because IP2 and IP3 were operated independently for an extended period of time, there are differences between IP2 and IP3 in terms of the number of systems, as well as system boundaries and intended functions for similarly named systems. The site component database along with system flow diagrams were used to define system boundaries and identify system intended functions. Consequently, certain similarly named SSCs were included within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(1) only for one unit and 10 CFR 54.4(a)(2) only for the other unit because the system boundaries were different.

The IP2 city water system (CYW) is in-scope for 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(2) while the IP3 city water system (CWM) is in-scope only for 10 CFR 54.4(a)(2). IP2 piping assigned to the city water system provides containment isolation, a 10 CFR 54.4(a)(1) intended function, for supply to fire water hose reels inside the containment building. The IP3 city water system does not provide a similar intended function or any other (a)(1) functions and therefore is not in-scope for 10 CFR 54.4(a)(1). Since the city water systems are fluid-filled, all components not included for 54.4(a)(1) or (a)(3) in structures containing components with safety functions were reviewed for potential spatial impact. Appropriate LRA drawings were also reviewed to verify that no components required for structural support of components with safety functions were excluded. This review was performed for both systems regardless of system functions to ensure all in-scope components were identified.

The IP2 instrument air closed cooling water system is in-scope only for 10 CFR 54.4(a)(2) while the IP3 instrument air closed-cooling system is in-scope for 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(2). IP3 instrument air closed-cooling heat exchangers SWN CLC 31 HTX, SWN CLC 32 HTX perform an intended function of providing service water system pressure boundary and are in-scope for 10 CFR 54.4(a)(1). The corresponding IP2 instrument air closed-cooling heat exchangers 21 CWHX, 22CWHX are assigned to the SW system and not instrument air closed-cooling, so the IP2 instrument air closed-cooling system has no components with a 10 CFR 54.4(a)(1) intended function. Since the instrument air closed-cooling systems are fluid-filled, all components in structures containing components with safety functions were reviewed for potential spatial impact. Appropriate LRA drawings were also reviewed to verify that no components required for structural support of components with safety functions were excluded. This review was performed for both systems regardless of system functions to ensure all in-scope components were identified.

The IP2 river water service system (RW) is in-scope for 10 CFR 54.4(a)(1) to support the service water system pressure boundary. Both IP2 and IP3 RW systems are in-scope for 10 CFR 54.4(a)(2). The IP3 RW system has no components within its boundary that support the service water system pressure boundary or any other (a)(1) functions. Since the RW systems are fluid-filled, all system components in structures containing components with safety functions were included for potential spatial impact. Appropriate LRA drawings were also reviewed to verify that no components required for structural support of components with safety functions were excluded. This review was performed for both systems regardless of system functions to ensure all in-scope components were included.

The staff reviewed the applicant’s response to RAI 2.1-1(c) and determined that the applicant’s description of the process used to ensure that SSCs have been appropriately included within the scope of license renewal is in accordance with 10 CFR 54.4(a)(1) or (a)(2), as applicable, based on the intended function of the SSC for the unit that the system serves. The staff’s concern described in RAI 2.1-1(c) is resolved.

2.1.4.1.3 Conclusion

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

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

2.1.4.2.1 Summary of Technical Information in the Application

In LRA Section 2.1.1.2, “Application of Criterion for Nonsafety-Related SSCs Whose Failure Could Prevent the Accomplishment of Safety Functions,” the applicant described the scoping methodology as it relates to the nonsafety-related criteria in 10 CFR 54.4(a)(2). The applicant based its 10 CFR 54.4(a)(2) scoping methodology on guidance provided in Appendix F of NEI 95-10, Revision 6. By considering functional failures and physical failures, the applicant evaluated the impacts of nonsafety-related SSCs that meet the 10 CFR 54.4(a)(2) criteria.

<u>Functional Failure of Nonsafety-Related SSCs</u>. LRA Section 2.1.1.2.1, “Functional Failures of Nonsafety-Related SSC,” states that SSCs required to perform a function in support of safety-related components are generally classified as safety related and are included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). For the few exceptions where nonsafety-related components are required to remain functional to support a safety function, the applicant identified this intended system function and included the components within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2).

<u>Nonsafety-Related SSCs with the Potential for Spatial Interaction with Safety-Related SSCs</u>. LRA Section 2.1.1.2.2, “Physical Failures of Nonsafety-Related SSCs,” states that nonsafety-related systems and nonsafety-related portions of safety-related systems are identified as in scope under 10 CFR 54.4(a)(2) if there is a potential for spatial interactions with safety-related equipment. Spatial failures are defined as failures of nonsafety-related SSCs that are connected to or located in the vicinity of safety-related SSCs, creating the potential for interaction between the SSCs from physical impact, pipe whip, jet impingement, a harsh environment resulting from a piping rupture, or damage from leakage or spray that could impede or prevent the accomplishment of the safety-related functions of a safety-related SSC. In addition, the applicant included overhead handling systems and mitigative features, such as missile barriers, flood barriers, and spray shields, within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

The applicant used the preventive option described in NEI 95-10, Appendix F, to determine the scope of license renewal with respect to the protection of safety-related SSCs from spatial interactions that the CLB does not address. This scoping process, referred to as the "spaces" approach, involves an evaluation based on the location of nonsafety-related equipment and its proximity to safety-related SSCs, including the identification of fluid-filled system components located in the same space as safety-related equipment. The applicant defined a "space" as a room or cubicle that is separated from other spaces by substantial objects (such as walls, floors, and ceilings).

Nonsafety-Related SSCs Directly Connected to Safety-Related SSCs. LRA Section 2.1.1.2.2 states that the scope of license renewal includes the nonsafety-related piping and supports up to and including the first seismic anchor beyond the safety/nonsafety interface such that the safety-related portion of the piping will be able to perform its intended function. For piping in this structural boundary, pressure integrity is not required; however, piping within the safety class pressure boundary depends on the structural boundary piping and supports so that the system can fulfill its safety function. For IP2 and IP3, "structural boundary" is defined as the portion of a piping system that, although outside the safety class pressure boundary, is relied on to provide structural support for the pressure boundary.

2.1.4.2.2 Staff Evaluation

As detailed in 10 CFR 54.4(a)(2), the applicant must consider all nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of safety-related SSCs relied on to remain functional during and following a DBE to ensure (1) the integrity of the 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.

Regulatory Guide 1.188, Revision 1, endorses the use of NEI 95-10, Revision 6. NEI 95-10 discusses the staff's position on the 10 CFR 54.4(a)(2) scoping criteria, including nonsafety-related SSCs typically identified in the CLB; consideration of missiles, cranes, flooding, and high-energy line breaks (HELBs); nonsafety-related SSCs connected to safety-related SSCs; nonsafety-related SSCs in proximity to safety-related SSCs; and the mitigative and preventive options related to nonsafety-related and safety-related SSC interactions.

In addition, the staff's position (as discussed in NEI 95-10, Revision 6) is that applicants should not consider hypothetical failures, but rather should base their evaluation on the plant's CLB, engineering judgment and analyses, and relevant operating experience. NEI 95-10 further describes operating experience as all documented plant-specific and industry-wide experience that can be used to determine the plausibility of a failure. Documentation would include NRC generic communications and event reports, plant-specific condition reports, industry reports such as safety operational event reports, and engineering evaluations. The staff reviewed LRA Section 2.1.1.2, in which the applicant described the scoping methodology for nonsafety-related SSCs under 10 CFR 54.4(a)(2). In addition, the staff reviewed the applicant's results report, which documents the guidance and corresponding results of the applicant's scoping review under 10 CFR 54.4(a)(2). The applicant stated that it performed this review in accordance with the guidance in NEI 95-10, Revision 6, Appendix F.

Nonsafety-Related SSCs Required To Perform a Function That Supports a Safety-Related SSC. The staff determined that nonsafety-related SSCs required to remain functional to support a safety-related function were included within the scope of license renewal as safety-related as if these SSCs were in scope under 10 CFR 54.4(a)(1). The applicant's scoping report discusses the evaluation criteria described in 10 CFR 54.4(a)(2). The staff finds that the applicant implemented an acceptable method for scoping of the nonsafety-related systems that perform a function that supports a safety-related intended function, as required by 10 CFR 54.4(a)(2).

Nonsafety-Related SSCs Directly Connected to Safety-Related SSCs. Based on a review of the information in the LRA and the applicant's implementing documents, the staff determined that, to identify the nonsafety-related SSCs connected to safety-related SSCs and which require structural soundness to maintain the integrity of the safety-related SSCs, the applicant used a combination of the information contained in the IP2 and IP3 structural analysis to identify the structural boundary. The applicant also applied the bounding approach as described in NEI 95-10, Appendix F. The applicant reviewed the safety-related to nonsafety-related interfaces for each mechanical system to identify the nonsafety-related components located between the interface and the structural boundary. The applicant included all nonsafety-related SSCs within the structural boundary that are within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2).

If a seismic support could not be located using the structural boundary, the applicant identified the portion of the nonsafety-related piping up to, and including, a base-mounted component, flexible connection, or the end of the piping run, in accordance with the guidance of Appendix F to NEI 95-10. This guidance describes the use of bounding criteria as a method of determining the portion of nonsafety-related SSCs that an applicant should include within the scope of license renewal.

The staff noted during the scoping and screening methodology audit that the applicant included fluid-filled, nonsafety-related pipes located in a safety-related space within the scope of license renewal based on the spaces approach; the applicant separately addressed nonsafety-related piping attached to safety-related SSCs. However, the applicant did not provide sufficient information in either the LRA or the implementing procedures to demonstrate that, when the fluid-filled pipe was also attached to a safety-related SSC, an additional portion of the pipe, beyond the safety-related space, up to and including an appropriate seismic anchor, equivalent anchor, or bounding condition, was also included within the scope of license renewal. The staff determined that it needed additional information to complete the review of the applicant's scoping methodology.

In RAI 2.1-1(a), dated January 14, 2008, the staff requested that the applicant describe the process used to ensure that fluid-filled, nonsafety-related pipe, attached to safety-related SSCs and exiting the safety-related space, was included within the scope of license renewal, up to and including an appropriate seismic anchor, equivalent anchor, or bounding condition.

In its February 13, 2008, response to RAI 2.1-1(a), the applicant stated the following:

> The process for determining the components to be included for 10 CFR 54.4(a)(2) included a review of all passive mechanical components at IP2 and IP3 that were not already included in an AMR report under 10 CFR 54.4(a)(1) or (a)(3). The review began with a determination of which components need to be in-scope due to their potential for spatial interaction with

> components with a safety function. If piping and components for fluid-filled systems exit areas containing components with safety functions, further review was performed. This occurred in only limited locations. For those few locations, IPEC [Indian Point Energy Center] reviewed the component database and associated drawings and confirmed that those components required for structural support are within the safety-related space.

The staff reviewed the applicant's response to RAI 2.1-1(a) and determined that the applicant described an adequate process, which includes additional review of certain fluid-filled, nonsafety-related pipe to ensure that fluid-filled, nonsafety-related pipe attached to safety-related SSCs that exits the safety-related space is included within the scope of license renewal, up to and including an appropriate seismic anchor, equivalent anchor, or bounding condition. The staff's concern described in RAI 2.1-1(a) is resolved.

Nonsafety-Related SSCs with the Potential for Spatial Interaction with Safety-Related SSCs. The applicant considered physical impact (pipe whip, jet impingement), harsh environments, flooding, spray, and leakage when evaluating the potential for spatial interactions between nonsafety-related systems and safety-related SSCs. The applicant used a spaces approach, as described above, to identify the portions of nonsafety-related systems with the potential for spatial interaction with safety-related SSCs.

Physical Impact or Flooding. The applicant considered nonsafety-related supports for nonseismic piping systems and electrical conduit and cable trays with potential for spatial interaction with safety-related SSCs for inclusion within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2). These supports and components are addressed in a commodity fashion, (i.e., grouping structural components that typically do not have unique identifiers based on common characteristics such as materials of construction, within civil/structural AMR reports). The applicant's review of earthquake experience revealed no occurrence of welded steel pipe segments falling during a strong motion earthquake. The applicant, using the guidance in NEI 95-10, concluded that, as long as the effects of aging on supports for piping systems are managed, collapse of piping systems is not credible (except from flow-accelerated corrosion as considered in the HELB analysis for high-energy systems) and the piping sections are not within scope under 10 CFR 54.4(a)(2). The applicant evaluated the missiles that could be generated from internal or external events such as failure of rotating equipment or overhead-handling systems. The applicant included nonsafety-related design features that protect safety-related SSCs from such missiles within the scope of license renewal. In addition, the applicant included walls, curbs, dikes, doors, and similar structures that provide flood barriers to safety-related SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

Pipe Whip, Jet Impingement, and Harsh Environment. The applicant evaluated nonsafety-related portions of high-energy lines in accordance with 10 CFR 54.4(a)(2). The applicant based its evaluation on a review of documents including the UFSARs, DBDs, and relevant site documentation. The applicant evaluated its high-energy systems to ensure identification of components that are part of nonsafety-related, high-energy lines that can affect safety-related equipment. If the applicant's HELB analysis assumed that a nonsafety-related piping system did not fail, or assumed failure only at specific locations, then the applicant included that piping system (piping, equipment, and supports) within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2), and designated it as subject to an AMR to ensure that those assumptions remain valid through the period of extended operation. Also, as discussed in the IP2 and IP3 scoping report (in accordance with 10 CFR 54.4(a)(2)), the applicant reviewed the reference documents (primarily DBDs) that contain HELB analyses for inside and outside containment and identified high-energy lines. Many of the identified systems are safety-related or are required for a regulated event and are included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1) or (a)(3). The applicant included remaining nonsafety-related, high-energy lines, which were determined to have potential interaction with safety-related SSCs, within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

Spray and Leakage. The applicant evaluated moderate and low-energy systems that have the potential for spatial interactions from spray or leakage. Nonsafety-related systems and nonsafety-related portions of safety-related systems with the potential for spray or leakage that could prevent safety-related SSCs from performing their required safety function were considered within the scope of license renewal. The applicant used a spaces approach to identify the nonsafety-related SSCs located within the same space as safety-related SSCs, as described above. After identifying the applicable mechanical systems, the applicant reviewed the system functions to determine whether the system contained fluid, air, or gas. On the basis of plant and industry operating experience, the applicant excluded the nonsafety-related SSCs containing air or gas from the scope of license renewal. The applicant then determined whether the system had any components located within a space containing safety-related SSCs. The applicant included those nonsafety-related SSCs determined to contain fluid and located within a space containing safety-related SSCs within the scope of license renewal.

RAI 2.1-1(b), dated January 14, 2008, states that during the staff audit, the audit team reviewed the applicant's technical evaluation and onsite documentation for nonsafety-related SSCs affecting safety-related SSCs. This technical evaluation found that certain nonsafety-related SSCs affecting safety-related SSCs were not included within the scope of license renewal, based on the proximity of the nonsafety-related SSCs to the safety-related SSCs. The staff requested that the applicant provide the rationale and basis for not including nonsafety-related SSCs in the vicinity of safety-related SSCs within the scope of license renewal, based on their proximity to safety-related SSCs.

In its February 13, 2008, response to RAI 2.1-1(b), the applicant stated the following:

> Within a structure that contains components with safety functions, the proximity of components to components with a safety function is not used as a criterion for exclusion of a system or component from (a)(2) scope due to spatial interaction. The wording in the original version of the AMR report reviewed during the license renewal scoping and screening audit did not clarify why fluid-filled components in locations with safety-related equipment were excluded. Some systems have fluid-filled nonsafety-related components located in structures that contain components with safety functions but cannot spatially affect components with safety functions due to physical barriers such as room separation within the structure. During the license renewal scoping and screening audit, a portion of the IP2 chlorination (CL) system was determined to be in proximity to service water system components which perform a safety function. The CL system had been excluded from 10 CFR 54.4(a)(2) scope. The CL system is added to the scope of license renewal for 10 CFR 54.4(a)(2) with components to be managed by the Periodic Surveillance and Preventive Maintenance, External Surfaces Monitoring, and Bolting Integrity Programs.

The staff reviewed the applicant's response to RAI 2.1-1(b) and determined that the applicant described an adequate process, including consideration of room boundaries to prevent interaction, to ensure that fluid-filled, nonsafety-related pipes were not excluded from the scope of license renewal based on the proximity of the nonsafety-related SSCs to safety-related SSCs. The applicant also concluded that an additional system, the chlorination system, is included within the scope of license renewal. SER Section 2.3A.3.19 documents the staff's review of the IP2 chlorination system that was added to the scope. SER Section 3.3A.2 documents the staff's evaluation of AMR results for the IP2 chlorination system components. The staff's concern described in RAI 2.1-1(b) is resolved.

Protective Features. The applicant evaluated protective features, such as whip restraints, spray shields, supports, and missile and flood barriers installed to protect safety-related SSCs against spatial interaction with nonsafety-related SSCs from fluid leakage, spray, or flooding. These protective features are credited in the plant design and included within the scope of license renewal.

2.1.4.2.3 Conclusion

On the basis of its review of the applicant's scoping process and systems (on a sampling basis), discussions with the applicant, and review of the information provided in the response to RAIs 2.1-1(a) and (b), the staff concludes that the applicant's methodology for identifying and including nonsafety-related SSCs that could affect the performance of safety-related SSCs within the scope of license renewal is consistent with the scoping criteria in 10 CFR 54.4(a)(2) and, therefore, is acceptable.

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

2.1.4.3.1 Summary of Technical Information in the Application

LRA Section 2.1.1.3, "Application of Criterion for Regulated Events," describes the methodology for identifying those systems and structures within the scope of license renewal in accordance with the Commission's criteria for five regulated events. These criteria appear in (1) 10 CFR 50.48, "Fire Protection," (2) 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants," (3) 10 CFR 50.61, "Fracture Toughness Requirements for Protection against Pressurized Thermal Shock Events," (4) 10 CFR 50.62, "Requirements for Reduction of Risk from Anticipated Transients without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants," and (5) 10 CFR 50.63, "Loss of All Alternating Current Power."

Fire Protection. LRA Section 2.1.1.3.1, "Commission's Regulations for Fire Protection (10 CFR 50.48)," describes the scoping of systems and structures relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the fire protection criterion. The LRA stated that in-scope systems and structures for fire protection include equipment based on the functional requirements defined in 10 CFR 50.48. The applicant identified this equipment based on a review of the CLB for systems and structures relied on for compliance with 10 CFR 50.48. The applicant indicated in the LRA that those SSCs credited with fire prevention, detection, and mitigation in areas containing equipment important to the plant's safe operation and equipment credited to achieve safe shutdown in the event of a fire are within the scope of license renewal.

Environmental Qualification. LRA Section 2.1.1.3.2, "Commission's Regulations for Environmental Qualification (10 CFR 50.49)," describes the scoping of systems and structures relied on in safety analyses or plant evaluations to perform a function in compliance with the environmental qualification (EQ) criterion. The LRA states that the EQ program satisfies the requirements of 10 CFR 50.49 and that, because a bounding approach was used for scoping electrical equipment, the electrical and I&C systems and electrical equipment contained in mechanical systems are included within the scope of license renewal by default.

Pressurized Thermal Shock. LRA Section 2.1.1.3.3, "Commission's Regulations for Pressurized Thermal Shock (10 CFR 50.61)," describes the scoping of systems and structures relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the pressurized thermal shock (PTS) criterion. The LRA states that for both IP2 and IP3, the only system relied on to comply with the PTS regulation is the reactor coolant system (RCS), specifically the reactor vessel.

Anticipated Transient without Scram. LRA Section 2.1.1.3.4, "Commission's Regulations for Anticipated Transients without Scram (10 CFR 50.62)," describes the scoping of systems and structures relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the ATWS criterion. The LRA states that the applicant determined the mechanical system intended functions supporting anticipated transient without scram (ATWS) regulation based on CLB information for IP2 and IP3. The LRA also states that, because the applicant used a bounding approach for scoping electrical and I&C equipment, the electrical and I&C systems contained in mechanical systems are included within the scope of license renewal by default.

Station Blackout. LRA Section 2.1.1.3.5, "Commission's Regulations for Station Blackout (10 CFR 50.63)," describes the scoping of systems and structures relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the SBO criterion. The LRA states that the applicant determined the system intended functions supporting 10 CFR 50.63 requirements based on information contained in the CLB. The LRA further states that, because the applicant used a bounding approach for scoping electrical and I&C equipment, the onsite electrical and I&C systems and electrical equipment contained in mechanical systems are included within the scope of license renewal by default.

2.1.4.3.2 Staff Evaluation

The staff reviewed the applicant's approach to identifying mechanical systems and structures relied on to perform functions meeting the requirements of the fire protection, EQ, PTS, ATWS, and SBO regulations. As part of its review, the staff (1) discussed the methodology with the applicant, (2) reviewed the documentation developed to support the approach, and (3) evaluated a sample of the mechanical systems and structures indicated as within the scope of license renewal in accordance with 10 CFR 54.4(a)(3).

The applicant's implementing procedures describe the process for identifying systems and structures within the scope of license renewal. The procedures state that all mechanical systems and structures that perform functions addressed in 10 CFR 54.4(a)(3) are to be included within the scope of license renewal and the results documented in scoping results reports. The results reports reference the information sources used for determining the systems and structures credited for compliance with the events listed in the specified regulations.

Fire Protection. The applicant's scoping results reports indicate that the applicant considered CLB documents to identify in-scope systems and structures. These documents include the (1) fire protection plan, which includes the fire protection program plan as required by 10 CFR 50.48; (2) IP2 and IP3 fire hazards analyses; and (3) safe-shutdown analyses for the requirements in Appendix R, "Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979," to 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities." The staff reviewed the scoping results reports in conjunction with the LRA and the IP2 and IP3 CLB information to validate the methodology for including the appropriate systems and structures within the scope of license renewal.

The staff found that the scoping results reports indicate which of the mechanical systems and structures are included within the scope of license renewal because they perform intended functions that meet 10 CFR 50.48 requirements. As an example, for a mechanical system, the applicant's IP2 fire hazards analysis report credits the reactor coolant pump (RCP) oil collection system, which is included under the IP2 fire protection—CO_2, Halon, and RCP oil collection systems. From this report, the applicant identified a license renewal intended function for the system as providing each RCP with an oil collection system designed to contain and direct the oil to remote storage containers if leakage occurs. The scoping results also identify structures within the scope of license renewal. For example, the foundation structures of the IP2 and IP3 fire water storage tanks are within the scope of license renewal because they maintain the structural integrity of the fire water storage tanks that support equipment credited in safe-shutdown capability analyses. The staff determined that the applicant's scoping methodology is adequate for including systems and structures credited in performing fire protection functions.

Environmental Qualification. The applicant employed a bounding approach for scoping plant electrical and I&C systems. All of these systems are included within the scope of license renewal, and electrical and I&C components in mechanical systems are included in the electrical systems. This method also includes within the scope of license renewal any equipment relied on to perform functions that demonstrate compliance with the EQ regulation.

The staff reviewed the LRA, implementing procedures, scoping results reports, and the IP2 and IP3 master EQ component equipment lists to verify that the applicant identified SSCs within the scope of license renewal that meet EQ requirements. The staff determined that the applicant's scoping methodology is adequate for identifying EQ SSCs within the scope of license renewal.

Pressurized Thermal Shock. The applicant addressed PTS requirements for the reactor vessels in a TLAA in LRA Section 4.2.5. This methodology is appropriate for identifying SSCs with functions credited for complying with the PTS regulation. For this requirement, the applicant identified the IP2 and IP3 reactor vessels as the only components within the scope of license renewal. SER Section 4.2.5 documents the staff's review of the applicant's PTS TLAA.

Anticipated Transient without Scram. The applicant's scoping results reports indicate that mechanical systems are included within the scope of license renewal because they perform intended functions that meet 10 CFR 50.62 requirements. The applicant determined the intended functions based on IP2 and IP3 CLB information and identified most in-scope components as electrical equipment in mechanical systems. For scoping electrical equipment, the applicant's bounding methodology included within the scope of license renewal all electrical and I&C systems in mechanical systems, by default. The applicant also conservatively included mechanical systems with ATWS intended functions based on CLB information from the SSFSs. The staff determined that this scoping methodology is adequate for identifying systems with functions credited for complying with the ATWS regulation.

Station Blackout. The scoping results reports identify the mechanical systems and structures credited with performing intended functions to comply with the SBO requirement. In its scoping effort, the applicant considered CLB information, including the UFSARs, SSFS, and the SBO report for electrical systems. The applicant used additional information (e.g., drawings and engineering judgment) to identify other systems that support SBO functions.

The applicant included within the scope of license renewal electrical equipment, mechanical systems, and structures with intended functions meeting SBO requirements. For scoping electrical equipment, the applicant's bounding methodology included within the scope of license renewal all electrical and I&C systems in mechanical systems by default. The mechanical systems and structures within the scope of license renewal are those relied on in the CLB for the 8-hour SBO coping duration phase and for the SBO recovery phase. The staff determined that this scoping methodology is adequate for identifying systems and structures with functions credited for complying with the SBO regulation. SER Section 2.5 documents the staff's review of the results of the implementation of the SBO scoping methodology.

2.1.4.3.3 Conclusion

The staff concludes that the applicant's methodology for identifying systems and structures meets the scoping criteria detailed in 10 CFR 54.4(a)(3) and, therefore, is acceptable. The staff based this conclusion on sample reviews, discussions with the applicant, and review of the applicant's scoping process.

2.1.4.4 Plant-Level Scoping of Systems and Structures

2.1.4.4.1 Summary of Technical Information in the Application

System- and Structure-Level Scoping. The applicant documented its methodology for performing the scoping of systems and structures in accordance with 10 CFR 54.4(a) in the LRA, guidance documents, and scoping and screening reports. The applicant's approach to system and structure scoping provided in the site guidance documents and implementing procedures is consistent with the methodology described in Section 2.1 of the LRA. Specifically, the implementing procedures require personnel performing license renewal scoping to use CLB documents, describe the system or structure, and include a list of functions that the system or structure is required to accomplish. Sources of information regarding the CLB for systems include the UFSARs, DBDs, P&IDs, Maintenance Rule information, drawings, and docketed correspondence. The applicant then compared identified system or structure function lists to the scoping criteria to determine whether the functions meet the scoping criteria of 10 CFR 54.4(a). The applicant documented the results of the plant-level scoping process in accordance with the implementing procedures. The results were provided in the systems and structures documents and reports that contain 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 intended functions of the system or structure.

Insulation. LRA Section 2.1.1, “Scoping Methodology,” states that insulation was treated as a bulk commodity for the purposes of scoping. LRA Section 2.4.4, “Bulk Commodities,” discusses insulation and states that certain insulation has the specific intended functions of (1) controlling the heat load during DBAs in areas with safety-related equipment or (2) maintaining integrity such that falling insulation (such as reflective metallic-type reactor vessel insulation) does not damage safety-related equipment and was included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1) or (a)(2) as applicable.

Consumables. In LRA Section 2.1.2.4, “Consumables,” the applicant used the information in SRP-LR Table 2.1-3 to categorize and evaluate consumables. For the purpose of license renewal, consumables were divided into four categories (a) packing, gaskets, component seals, and O-rings, (b) structural sealants, (c) oil, grease, and component filters, and (d) system filters, fire extinguishers, fire hoses, and air packs.

Group (a) consumables (packing, gaskets, component mechanical seals, and O-rings) are typically used to provide a leakproof seal when components are mechanically joined together. These items are commonly found in components such as valves, pumps, heat exchangers, ventilation units or ducts, and piping segments. According to American National Standards Institute (ANSI) B31.1 and American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code Section III, the subcomponents of these pressure-retaining components are not pressure-retaining parts. Therefore, these subcomponents are not relied on to perform a pressure boundary intended function and are not subject to an AMR.

Group (b) consumables (elastomers and other materials used as structural sealants) are subject to an AMR if they are not periodically replaced and they perform an intended function, typically supporting a pressure boundary, flood barrier, or rated fire barrier. Seals and sealants, including pressure boundary sealants, compressible joints and seals, seismic joint filler, and waterproofing membranes, are included in the AMR of bulk commodities. Sealants with a pressure boundary function are included in the AMR of the containment buildings.

Group (c) consumables (oil, grease, and component filters) are treated as consumables because either (1) they are periodically replaced or (2) they are monitored and replaced based on condition. They are not subject to an AMR.

Group (d) consumables (system filters, fire hoses, fire extinguishers, self-contained breathing apparatus, and self-contained breathing apparatus cylinders) are considered consumables because they are routinely tested and inspected and they are replaced when necessary. Periodic inspection procedures specify the replacement criteria of these components that are routinely checked by tests or inspections. Therefore, while these consumables are in the scope of license renewal, they are not subject to an AMR.

2.1.4.4.2 Staff Evaluation

During the audit, the staff reviewed the applicant’s methodology for performing the scoping of plant systems and structures to ensure that it is consistent with 10 CFR 54.4(a). The methodology used by the applicant to determine the systems and structures within the scope of license renewal is documented in implementing procedures and scoping results reports for mechanical systems. The scoping process defines the plant in terms of systems and structures. Specifically, the implementing procedures identify the systems and structures that are subject to review in accordance with 10 CFR 54.4(a) and describe the processes for capturing the results of the review. The procedures are used to determine whether the system or structure performs intended functions consistent with the requirements of 10 CFR 54.4(a). The implementing procedures indicate that the applicant completed this process for all systems and structures to ensure that the entire plant was addressed. During the audit, the staff reviewed a sampling of the documents and reports and concluded that the applicant's scoping results contain an appropriate level of detail to document the scoping process.

2.1.4.4.3 Conclusion

Based on its review of the LRA, site guidance documents, and scoping and screening implementing procedures, and based on 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 Scoping

2.1.4.5.1 Summary of Technical Information in the Application

LRA Section 2.1.1 describes the methodology for identifying license renewal evaluation boundaries. For mechanical systems, the mechanical components include those portions of the system that are necessary to ensure that the intended functions will be performed. The LRA states that components needed to support each of the system-level intended functions identified in the scoping process are included within the evaluation boundary.

The LRA states that, for mechanical system scoping, system boundaries were defined in part by the collection of components in the database assigned to the system code. The database represents all systems and contains the vast majority of system components. The database was useful in preparing the list of plant systems but could not be used alone to determine all system boundaries.

In addition, the LRA states that flow diagrams were used with the component database to help define system boundaries. System functions were determined based on the functions performed by the components within those boundaries. The LRA notes that, because of the differences in IP2 and IP3 system boundaries, the intended functions for the systems are often different, even for similarly named systems. The applicant evaluated structural commodities associated with mechanical systems, such as pipe hangers and insulation, with the structural bulk commodities, (i.e., grouping structural components that typically do not have unique identifiers that are common to in-scope systems and structures (e.g., anchors, embedments, equipment supports, insulation)), while it evaluated electrical and I&C components separately. The evaluation boundaries for mechanical systems were documented on license renewal drawings created by marking mechanical P&IDs to indicate the components within the scope of license renewal. The applicant evaluated mechanical systems against the criteria of 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

2.1.4.5.2 Staff Evaluation

The staff evaluated LRA Section 2.1 and the guidance in the implementing procedures and reports in its review of the mechanical scoping process. The implementing procedures and reports provide instructions for identifying the evaluation boundaries. An understanding of system operations in support of intended functions is required to determine the mechanical system evaluation boundary.

This process is based on the review of Maintenance Rule basis documents, DBDs, SSFSs, the fire hazards analysis, the safe-shutdown analysis, internal flooding analyses, technical specifications, applicable sections of the UFSARs, and plant drawings. The evaluation boundaries for mechanical systems are documented on license renewal boundary drawings that were created by marking mechanical P&IDs to indicate the components within the scope of license renewal and subject to an AMR. Components within the evaluation boundary were reviewed to determine if they perform an intended function. Intended functions were established based on whether a particular function of a component is necessary to support the system functions that meet the scoping criteria.

The staff reviewed the implementing procedures and the CLB documents associated with mechanical system scoping and found that the guidance and CLB source information are acceptable to identify mechanical components and support structures in mechanical systems that are within the scope of license renewal. The staff conducted detailed discussions with the applicant’s license renewal project management personnel and reviewed documentation pertinent to the scoping process. The staff assessed whether the applicant had appropriately applied the scoping methodology outlined in the LRA and implementing procedures and whether the scoping results are consistent with CLB requirements.

The staff determined that the applicant’s procedure is consistent with the description in LRA Section 2.1 and the guidance in SRP-LR Section 2.1 and was adequately implemented.

On a sampling basis, the staff reviewed the applicant’s methodology for identifying SW system mechanical component types meeting the scoping criteria of 10 CFR 54.4. The staff also reviewed the implementing procedures for the scoping methodology and discussed the methodology and results with the applicant. The staff verified that the applicant had identified and used pertinent engineering and licensing information to determine the SW system mechanical component types that fall within the scope of license renewal. As part of the review process, the staff evaluated each system intended function identified for the SW system, the basis for inclusion of the intended function, and the process used to identify each of the system component types. The staff verified that the applicant had identified and highlighted system P&IDs to develop the license renewal boundaries in accordance with the procedural guidance.

Based on its review of the LRA, scoping implementing procedures, the sample system, and review and discussions with the applicant, the staff verified that the applicant is knowledgeable about the process and conventions for establishing boundaries, as defined in the license renewal implementing procedures, and that the applicant independently verified the results in accordance with the implementing procedures. Specifically, other license renewal personnel knowledgeable about the system independently reviewed the marked-up drawings to ensure accurate identification of the system intended functions. The applicant performed additional cross-discipline verification and independent reviews of the associated drawings before approving the scoping effort.

2.1.4.5.3 Conclusion

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

2.1.4.6 Structural Scoping

2.1.4.6.1 Summary of Technical Information in the Application

In LRA Section 2.1.1, the applicant described the methodology for identifying structures that are within the scope of license renewal. The applicant developed a list of plant structures from a review of plant layout drawings, Maintenance Rule documentation, DBDs, and the UFSARs. The structures list includes all structures that potentially support plant operations or could adversely impact structures that support plant operations. In addition to buildings and facilities, the list of structures includes other structures that support plant operation.

The applicant identified intended functions for structures and mechanical systems based on reviews of applicable plant licensing and design documentation. The applicant reviewed documents that included Maintenance Rule documents, DBDs, site SSFSs, the fire hazards analysis, the safe-shutdown analysis, internal flooding analyses, technical specifications, the UFSARs, and station drawing. The LRA states that the applicant evaluated each structure against the criteria of 10 CFR 54.4(a)(1), (a)(2), and (a)(3).

2.1.4.6.2 Staff Evaluation

The staff reviewed the applicant's approach for identifying structures relied on to perform the license renewal intended functions in accordance with 10 CFR 54.4(a). As part of this review, the staff discussed the methodology with the applicant, reviewed the documentation developed to support the applicant's review, and evaluated the scoping results for several structures that were identified as within the scope of license renewal.

The applicant identified and developed a list of plant structures and the structures' intended functions, through a review of the UFSARs, Maintenance Rule documents, the fire hazards analysis, DBDs, and structural drawings. The applicant determined that the primary structural safety functions applicable to the requirements of 10 CFR 54.4(a)(1) were to provide (1) containment of radioactive products to mitigate post-accident offsite doses and (2) to support or protect safety-related equipment. The applicant also included structures housing safety-related SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

The staff reviewed selected portions of the UFSARs, Maintenance Rule documents, the fire hazards analysis, DBDs, structural drawings, implementing procedures, and selected AMR reports to verify the adequacy of the methodology.

In addition, the staff reviewed the scoping results, including information contained in the source documentation for the turbine building, to verify that application of this methodology would provide the results as documented in the LRA. The staff verified that the applicant had identified and used pertinent engineering and licensing information to determine the turbine building structural component types that fall within the scope of license renewal. As part of the review process, the staff evaluated the intended functions identified for the turbine building, the basis for inclusion of the intended functions, and the process used to identify each of the component types.

2.1.4.6.3 Conclusion

Based on the staff's review of information in the LRA, the applicant's detailed scoping procedures, and a review of a sample of structural scoping results, the staff concluded that the applicant's methodology for identification of the structures within the scope of license renewal is consistent with the requirements of 10 CFR 54.4 and, therefore, is acceptable.

2.1.4.7 Electrical Scoping

2.1.4.7.1 Summary of Technical Information in the Application

LRA Section 2.1.1 states that, for the purposes of system-level scoping, all plant electrical and I&C systems are included in the scope of license renewal. The evaluation of electrical systems includes electrical and I&C components in mechanical systems.

LRA Section 2.5, "Scoping and Screening Results: Electrical and Instrumentation and Control Systems," states that the applicant included electrical and I&C components within the scope of license renewal unless they were specifically screened out. When used with the plant spaces approach, this method eliminates the need for unique identification of every component and its specific location and ensures that components are not improperly excluded from an AMR.

The applicant began the electrical and I&C scoping process by grouping the total population of components into commodity groups. The commodity groups include similar electrical and I&C components with common characteristics. The applicant identified component-level intended functions of the commodity groups. During the IPA, commodity groups and specific plant systems were eliminated from further review as the intended functions of commodity groups were examined.

2.1.4.7.2 Staff Evaluation

The staff reviewed the applicant's approach for identifying electrical and I&C SSCs relied on to perform the license renewal intended functions detailed in 10 CFR 54.4(a). As part of this review, the staff reviewed the implementing procedures and documentation developed to support the applicant's review and evaluated, on a sampling basis, the scoping results for several electrical systems identified as within the scope of license renewal.

The staff evaluated LRA Sections 2.1.1 and 2.5, scoping implementing procedures, scoping reports and aging management reports, as documented in the audit report, governing the electrical scoping methodology. The staff determined that the scoping phase for electrical components began with placing all electrical components from plant systems within the scope of license renewal. In addition, non-plant electrical systems including certain switchyard components required to support SBO and to restore offsite power were included within the scope of license renewal. The staff determined that the data sources used for scoping included the UFSARs, DBDs, cable database, component database, the station single-line drawings, cable procurement specifications, electrical drawings, the EQ master list, the IP2 and IP3 fuse list, and connection diagrams to identify the electrical and I&C components.

During the scoping methodology audit, the staff reviewed the applicant's process for identifying fuse holders within the scope of license renewal. The staff determined that the applicant had reviewed the plant fuse list and connection diagrams to identify fuses outside of complex assemblies and had determined that no fuses were within the scope of license renewal. During the scoping methodology audit, the staff reviewed the applicant's process for identifying tie wraps within the scope of license renewal. The staff determined that the applicant had reviewed the CLB for credit taken for tie wrap installation and reviewed operating experience to determine if the nonsafety-related tie wraps could affect a safety-related function, but did not identify any tie wraps within the scope of license renewal. The staff reviewed selected portions of the data sources and selected several examples of components for which the applicant demonstrated the process used to determine that electrical components were within the scope of license renewal.

2.1.4.7.3 Conclusion

On the basis of the review of information contained in the LRA, the applicant's scoping implementing procedures, and a review of a sample of electrical scoping results, the staff concludes that the applicant's methodology for identification of electrical components within the scope of license renewal is consistent with the requirements of 10 CFR 54.4 and, therefore, is acceptable.

SER Section 2.5 documents the results of the staff's review of the implementation of the SBO scoping methodology.

2.1.4.8 Conclusion for Scoping Methodology

On the basis of its review of the LRA and the scoping implementation procedures, the staff concludes that the applicant's scoping methodology is consistent with the guidance contained in the SRP-LR and identifies those SSCs (1) that are safety related, (2) whose failure could affect safety-related functions, and (3) that are necessary to demonstrate compliance with NRC regulations for fire protection, EQ, PTS, ATWS, and SBO. The staff concludes that the applicant's methodology is consistent with the requirements of 10 CFR 54.4(a) and, therefore, is acceptable.

2.1.5 Screening Methodology

2.1.5.1 General Screening Methodology

2.1.5.1.1 Summary of Technical Information in the Application

In LRA Section 2.1.2, "Screening Methodology," the applicant described its process for determining which components and structural elements require an AMR. Screening is the process by which the applicant identifies SCs within the scope of license renewal that perform an intended function, as described in 10 CFR 54.4, without moving parts or without a change in configuration or properties, and that are not subject to replacement based on a qualified life or specified time period.

LRA Section 2.1.6 states that the screening process for IP2 and IP3 followed the recommendations of NEI 95-10. For the group of systems and structures that were within the scope of license renewal, the applicant determined that passive long-lived components or structural elements that perform license renewal intended functions require an AMR. Components or structural elements that are either active or subject to replacement based on a qualified life do not require an AMR. Although the requirements for the IPA are the same for each system and structure, in practice, the screening process differed for mechanical systems, electrical systems, and structures.

2.1.5.1.2 Staff Evaluation

As required by 10 CFR 54.21, each LRA must contain an IPA that identifies SCs that are within the scope of license renewal and 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 components), as well as components that are not subject to periodic replacement based on a qualified life or specified time period (long-lived components). The IPA includes a description and justification of the methodology used to determine the passive and long-lived SCs and a demonstration that the effects of aging on those SCs will be adequately managed so that the intended function(s) will be maintained under all design conditions imposed by the plant-specific CLB for the period of extended operation.

The staff reviewed the methodology used by the applicant to determine whether mechanical and structural component types and electrical commodity groups within the scope of license renewal should be subject to an AMR. The applicant implemented a process for determining which SCs are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). In LRA Section 2.1.2, the applicant discussed these screening activities as they relate to the component types and commodity groups within the scope of license renewal.

The applicant applied the screening process to evaluate the component types and commodity groups included within the scope of license renewal and to determine which ones were passive and long lived and, therefore, subject to an AMR. The staff reviewed LRA Sections 2.3, 2.4, and 2.5, which provide the results of the process used by the applicant to identify component types and commodity groups subject to an AMR. During the scoping and screening methodology audit, the staff discussed the processes used for each discipline, reviewed the implementing procedures describing the screening methodology, and reviewed documentation of the screening results. On a sampling basis, the staff also reviewed the screening results reports for the SW system and the turbine building. The following sections of this SER discuss specific methodologies for mechanical, electrical, and structural components.

2.1.5.2 Mechanical Component Screening

2.1.5.2.1 Summary of Technical Information in the Application

LRA Section 2.1.2.1, “Screening of Mechanical Systems,” discusses the screening methodology for identifying passive and long-lived mechanical components and their support structures that are subject to an AMR.

License renewal drawings were prepared to indicate portions of systems that support system intended functions within the scope of license renewal, with the exception of those systems that are within scope under 10 CFR 54.4(a)(2) for physical interactions.

2.1.5.2.2 Staff Evaluation

The staff evaluated the mechanical screening methodology discussed and documented in LRA Section 2.1.2.1, implementing procedures, AMR reports, and the license renewal drawings. The mechanical system screening process began with the results from the scoping process. The applicant reviewed each system evaluation boundary as illustrated on P&IDs to identify passive and long-lived components. Within the system evaluation boundaries, all passive, long-lived components that perform or support a license renewal intended function are subject to an AMR. The results of the review are documented in the AMR reports. The AMR reports contain information such as the sources reviewed and the intended functions of the system.

During the scoping and screening methodology audit, the staff reviewed the results of the boundary evaluations and discussed the process with the applicant. The staff verified that mechanical system evaluation boundaries were established for each system within the scope of license renewal and that the boundaries were determined by mapping the system intended function boundaries onto P&IDs. The applicant reviewed the components within the system intended function boundary to determine whether the component supported the system's intended function. Components that supported the system's intended function were reviewed to determine whether the component was passive and long lived and, therefore, subject to an AMR.

The staff reviewed selected portions of the UFSARs, Maintenance Rule documents, the fire hazards analysis, DBDs, structural drawings, implementing procedures, and selected AMR reports. The staff conducted detailed discussions with the applicant's license renewal team and reviewed documentation pertinent to the screening process. The staff assessed whether the mechanical screening methodology outlined in the LRA and procedures was appropriately implemented and whether the scoping results are consistent with CLB requirements. The staff also reviewed the mechanical screening results for the SW system to verify proper implementation of the screening process. These audit activities revealed no discrepancies between the methodology documented and the implementation results.

2.1.5.2.3 Conclusion

Based on its review of the LRA, the implementing procedures, and a sample of the SW system screening results, the staff concludes that the applicant's mechanical component screening methodology is consistent with the SRP-LR guidance. The staff concludes that the applicant's methodology for identification of passive, long-lived mechanical components within the scope of license renewal and subject to an AMR is consistent with the requirements of 10 CFR 54.21(a)(1) and, therefore, is acceptable.

2.1.5.3 Structural Component Screening

2.1.5.3.1 Summary of Technical Information in the Application

LRA Section 2.1.2.2, "Screening of Structures," states that, for each structure within the scope of license renewal, the screening process identified those structural components that are subject to an AMR. LRA Section 2.4 presents the results for structures. The screening process for structural components involved a review of DBDs, design drawings, general arrangement drawings, penetration drawings, the UFSARs, plant modifications, system descriptions, and plant walkdowns to identify specific structural components and commodities that make up the structure. The LRA states that structures are inherently passive and, with few exceptions, are long lived. Therefore, the screening of structural components and commodities was based primarily on whether they perform an intended function. The applicant grouped structural components as commodities based on materials of construction (steel, bolted connections, concrete, and other materials). The applicant evaluated structural components and commodity groups to identify intended functions as they relate to license renewal.

2.1.5.3.2 Staff Evaluation

The staff reviewed the applicant's methodology for identifying structural components that are subject to an AMR as required by 10 CFR 54.21(a)(1). As part of this review, the staff discussed the methodology with the applicant, reviewed the documentation developed to support the activity, and evaluated the screening results for several structures that were identified within the scope of license renewal.

The staff reviewed the applicant's methodology used for structural screening described in the LRA sections noted above and in the applicant's implementing procedures and AMR reports. The applicant performed the screening review in accordance with the implementing procedures and identified pertinent structure design information, components, materials, environments, and aging effects. The staff verified that the applicant determined that structures are inherently passive and long lived, such that the screening of structural components and commodities was based primarily on whether they perform an intended function. During the scoping and screening methodology audit, the staff discussed the screening methodology and, on a sampling basis, reviewed the screening reports for a selected group of structures.

The staff reviewed selected portions of the UFSARs, Maintenance Rule documents, the fire hazards analysis, DBDs, structural drawings, implementing procedures, and selected AMR reports. The staff conducted detailed discussions with the applicant's license renewal team and reviewed documentation pertinent to the screening process. The staff assessed whether the screening methodology outlined in the LRA and implementing procedures was appropriately implemented and whether the scoping results are consistent with CLB requirements.

The staff also reviewed structural screening results for SCs contained in the turbine building to verify proper implementation of the screening process. Based on these audit activities, the staff identified no discrepancies between the methodology documented and the implementation results.

2.1.5.3.3 Conclusion

On the basis of the staff's review of information contained in the LRA, the applicant's detailed implementing procedures, and a review of a sample of structural screening results, the staff concludes that the applicant's methodology for identifying structural components within the scope of license renewal and subject to an AMR is consistent 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

In LRA Section 2.1.2.3, "Electrical and Instrumentation and Control Systems," the applicant discussed the screening of electrical and I&C system components. For each electrical system within the scope of license renewal, the screening process identified those electrical components and commodity groups that are subject to an AMR. Electrical components in mechanical systems were included in the scope of license renewal and were addressed under the electrical screening process.

The LRA states that the process of electrical screening differs from the mechanical and structural processes because the electrical components were addressed completely within their respective commodity groups. The applicant assigned each electrical component within the scope of license renewal to an electrical component commodity group for the screening evaluation. An electrical commodity group is a collection of electrical components grouped by type of equipment or function.

In the LRA, the applicant indicated that for the electrical equipment within the scope of license renewal, the passive, long-lived components that perform or support an intended function are subject to an AMR. Appendix B to NEI 95-10 identifies the electrical commodity groups considered to be passive and potentially requiring an AMR. For IP2 and IP3, electrical commodity groups were identified and cross-referenced to the appropriate NEI 95-10 commodity, which identifies the passive commodity groups. Electrical commodity groups determined to be active were not subject to an AMR. Electrical commodity groups that are not subject to replacement based on a qualified life or specified time period were considered long lived. The applicant further stated that components subject to replacement and addressed in replacement programs, such as the EQ Program, are not subject to an AMR.

2.1.5.4.2 Staff Evaluation

The staff reviewed the applicant's methodology for electrical screening, described in LRA Section 2.1.2.3, and the applicant's implementing procedures and AMR reports. The applicant used the screening process described in these documents to identify the electrical commodity groups subject to AMR.

The applicant used the component database, the station's single-line drawings, and cable procurement specifications as data sources to identify the electrical and I&C commodity groups subject to an AMR. The applicant also reviewed additional IP2 and IP3 documents such as electrical drawings and the EQ master list to validate the listing as complete.

The applicant determined that two commodity groups meet the passive criteria in accordance with NEI 95-10—(1) high-voltage insulators and (2) cables and connections, bus, and electrical portions of electrical and I&C penetration assemblies. The applicant evaluated the identified passive commodity groups to determine whether they are subject to replacement based on a qualified life or specified time period (short lived) or not subject to replacement based on a qualified life or specified time period (long lived). The applicant determined that the other electrical and I&C commodity groups are active and do not require an AMR. The staff reviewed the screening of selected components to verify the correct implementation of the methodology. The staff also reviewed selected electrical screening results, on a sampling basis, to verify proper implementation of the screening process. Based on these audit activities, the staff identified no discrepancies between the methodology documented and the implementation results.

2.1.5.4.3 Conclusion

The staff reviewed the LRA, procedures, electrical drawings, and a sample of the results of the screening methodology. The staff concludes that the applicant's methodology is consistent with the description in the LRA and the applicant's implementing procedures. On the basis of its review of information contained in the LRA, the applicant's implementing procedures, and a review of a sample of electrical screening results, the staff concludes that the applicant's methodology for identifying electrical commodity groups within the scope of license renewal and subject to an AMR is consistent with the requirements of 10 CFR 54.21(a)(1) and, therefore, is acceptable.

2.1.5.5 Screening Methodology Conclusion

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

2.1.6 Summary of Evaluation Findings

The staff's 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, and the applicant's responses dated February 13, 2008, to the staff's RAIs formed the basis of the staff's evaluation. The staff verified 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 confirmed 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

SER Section 2.2A presents plant-level scoping results for IP2; SER Section 2.2B presents plant-level scoping results for IP3.

2.2A IP2 Plant-Level Scoping Results

2.2A.1 Introduction

In LRA Section 2.1, the applicant described the methodology for identifying SSCs within the scope of license renewal and subject to an AMR. The applicant applied the scoping methodology to determine which SSCs must be included within the scope of license renewal. LRA Section 2.2 provides the results of the applicant's review. The staff reviewed the plant-level scoping results to determine whether the applicant had properly identified all systems and structures relied on to mitigate DBEs, as required by 10 CFR 54.4(a)(1); systems and structures whose failure could prevent satisfactory accomplishment of any safety-related functions, as required by 10 CFR 54.4(a)(2); and systems and structures relied on in safety analyses or plant evaluations to perform functions in accordance with 10 CFR 54.4(a)(3).

2.2A.2 Summary of Technical Information in the Application

In LRA Table 2.2-1a-IP2, the applicant listed the plant mechanical systems within the scope of license renewal for IP2. In LRA Table 2.2-1b-IP2, the applicant listed the plant electrical and I&C systems within the scope of license renewal for IP2. In LRA Table 2.2-3, the applicant listed the structures that are within the scope of license renewal for IP2. In LRA Tables 2.2-2-IP2, “Mechanical Systems Not within the Scope of License Renewal,” and 2.2-4, the applicant listed the systems and structures that are not within the scope of license renewal. Systems and structures that exist only at one unit are marked in the tables, as appropriate. 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.

2.2A.3 Staff Evaluation

The staff reviewed the scoping and screening methodology and provides its evaluation in SER Section 2.1. To verify that the applicant properly implemented its methodology, the staff’s review focused on the implementation results shown in LRA Tables 2.2-1a-IP2, 2.2-1b-IP2, 2.2-2-IP2, 2.2-3, and 2.2-4. In its review, the staff sought to confirm that the applicant had not omitted any plant-level system or structure from the scope of license renewal.

The staff reviewed the systems and structures that the applicant did not identify as within the scope of license renewal to determine whether they perform any intended functions that would require their inclusion within the scope of license renewal. The staff reviewed the applicant’s implementation results in accordance with the guidance in SRP-LR Section 2.2, “Plant-Level Scoping Results.”

During its review of LRA Section 2.2, the staff identified an area in which it required additional information to complete its review of the applicant’s plant-level scoping results. The applicant’s responses to the staff’s RAIs are discussed below.

In RAI 2.2A-1, dated December 7, 2007, the staff noted that LRA Table 2.2-2-IP2 excludes the hot penetration cooling system from the scope of license renewal and references UFSAR Section 5.1.4.2.2 as the basis for this decision. The staff further noted that UFSAR Section 5.1.4.2.2 provides a local area temperature limit of 250 degrees Fahrenheit (F) and states that air-to-air heat exchangers provide cooling for hot penetrations. The staff noted that cooling of hot containment penetrations minimizes age-related, heat-induced degradation of local concrete surrounding the penetration; therefore, the system may have an intended function, as defined in 10 CFR 54.4(a). The staff requested that the applicant justify the exclusion of the hot penetration cooling system from the scope of license renewal.

In its response, dated January 4, 2008, the applicant stated that the hot penetration cooling system removes heat from penetrations for hot piping systems to limit the temperature of the surrounding concrete during normal plant operation. The applicant further explained that the hot penetration cooling system is not required to function during accident conditions and has no function that meets the requirements of 10 CFR 54.4(a)(1). Additionally, the applicant explained that the hot penetration cooling system is not relied on to perform intended functions in accordance with 10 CFR 54.4(a)(2) or 10 CFR 54.4(a)(3); therefore, it is not within the scope of license renewal. The applicant provided the following evaluation:

> In order to lose significant structural properties, concrete must be held at high temperatures for an extended period of time. The hottest penetrations at IPEC are the MS lines, which normally operate at a temperature of 507°F. The results of a heat transfer analysis indicate that in the improbable case that all cooling air would be lost to the main steam penetration; the surrounding concrete would reach a maximum temperature of 200°F in approximately 1000 hours. It is not credible that cooling air would be lost for a significantly long period of time since the failure of the air blower drive motors is alarmed in the control room. Therefore, the failure of the hot penetration cooling system would not adversely impact the concrete in the penetrations.

Based on its review, the staff finds the response to RAI 2.2A-1 acceptable because the applicant adequately explained that the hot penetration cooling system is not safety related and its failure would not adversely affect a safety-related system or structure. The staff confirmed that the hot penetration cooling system is not credited in any accident analyses in the applicant's CLB. The staff's concern described in RAI 2.2A-1 is resolved.

During the NRC's onsite scoping and screening audit, the staff reviewed the applicant's onsite documentation for the potential interaction of SSCs based on the proximity of nonsafety-related SSCs to safety-related SSCs. In RAI 2.1-1, dated January 14, 2008, the staff asked the applicant to provide a technical basis for excluding these systems from scope. In its response, dated February 13, 2008, the applicant provided an evaluation of these systems and amended the LRA to include the IP2 chlorination system within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). Hence, as noted in the above section, the applicant added the IP2 chlorination system to LRA Table 2.3.3-19-A-IP2. Additionally, the applicant added LRA Table 2.3.3-19-44-IP2 to identify the component types subject to an AMR. Based on a review of this response, the staff finds that the applicant has adequately identified systems required to be within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

2.2A.4 Conclusion

The staff reviewed LRA Section 2.2, the RAI responses, and the UFSAR supporting information to determine whether the applicant failed to identify any systems and structures within the scope of license renewal. The staff found an instance in which the applicant omitted a system that should have been included within the scope of license renewal. The applicant has satisfactorily resolved this issue as discussed in the preceding staff evaluation. Therefore, on the basis of its review, the staff concludes that the applicant has appropriately identified the mechanical systems and structures within the scope of license renewal, as required by 10 CFR 54.4(a).

2.2B IP3 Plant-Level Scoping Results

2.2B.1 Introduction

In LRA Section 2.1, the applicant described the methodology for identifying SSCs within the scope of license renewal and subject to an AMR. The applicant applied the scoping methodology to determine which SSCs must be included within the scope of license renewal. LRA Section 2.2 provides the results of the applicant's review. The staff reviewed the plant-level scoping results to determine whether the applicant had properly identified all systems and structures relied on to mitigate DBEs, as required by 10 CFR 54.4(a)(1); systems and structures whose failure could prevent satisfactory accomplishment of any safety-related functions, as required by 10 CFR 54.4(a)(2); and systems and structures relied on in safety analyses or plant evaluations to perform functions in accordance with 10 CFR 54.4(a)(3).

2.2B.2 Summary of Technical Information in the Application

In LRA Table 2.2-1a-IP3, the applicant listed the plant mechanical systems within the scope of license renewal for IP3. In LRA Table 2.2-1b-IP3, the applicant listed the plant electrical and I&C systems within the scope of license renewal for IP3. In LRA Table 2.2-3, the applicant listed the structures that are within the scope of license renewal for IP3. In LRA Tables 2.2-2-IP3, "Mechanical System Not within the Scope of License Renewal," and 2.2-4, the applicant listed the systems and structures that are not within the scope of license renewal. Systems and structures that exist only at one unit are marked in the tables, as appropriate. 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.

2.2B.3 Staff Evaluation

The staff reviewed the scoping and screening methodology and provides its evaluation in SER Section 2.1. To verify that the applicant properly implemented its methodology, the staff's review focused on the implementation results shown in LRA Tables 2.2-1a-IP3, 2.2-1b-IP3, 2.2-2-IP3, 2.2-3, and 2.2-4. In its review, the staff sought to confirm that no plant-level systems or structures were omitted from the scope of license renewal.

The staff reviewed the systems and structures that the applicant did not identify as within the scope of license renewal to determine whether they perform any intended functions that would require their inclusion within the scope of license renewal. The staff conducted its review of the applicant's implementation in accordance with the guidance in SRP-LR Section 2.2.

During its review of LRA Section 2.2, the staff identified areas in which it required additional information to complete its review of the applicant's plant-level scoping results. The applicant's responses to the staff's RAIs are discussed below.

In RAI 2.2B-1, dated December 7, 2007, the staff noted that LRA Table 2.2-2-IP3 excludes the breathable air system from the scope of license renewal and references UFSAR Section 9.10 as the basis for this decision. The staff further noted that UFSAR Section 9.10 states that the breathable air system is a non-Category I system, except for the penetration into containment, where breathable air is provided inside containment through a spare penetration line. The staff noted that the breathable air system's containment penetration should be within the scope of license renewal in accordance with 10 CFR 54.4(a)(1), and requested that the applicant confirm whether the containment penetration is within the scope of license renewal.

In its response, dated January 4, 2008, the applicant stated that the breathable air containment penetration, designated as "X-X," is within the scope of license renewal and was reviewed as part of the containment penetration system in LRA Section 2.3.2.5. The applicant further explained that the containment penetration for the breathable air system is subject to an AMR.

Based on its review, the staff finds the response to RAI 2.2B-1 acceptable because the applicant adequately explained that containment penetration "X-X" for the breathable air system was evaluated with the containment penetration system. Furthermore, the staff confirmed that the LRA identified the breathable air containment penetration as requiring an AMR. The staff's concern described in RAI 2.2B-1 is resolved.

In RAI 2.2B-2, dated February 13, 2008, the staff noted that nonsafety-related SSCs directly connected to safety-related SSCs must be structurally sound to maintain the pressure boundary integrity of safety class piping. The nonsafety-related piping and supports up to and including the first seismic anchor beyond the safety/nonsafety interface may need to be within scope to ensure that the safety-related portion of the piping will be able to perform its intended function.

LRA Table 2.2-2-IP3 excluded the hydrogen gas system from the scope of license renewal. This system, along with the nitrogen system, provides the volume control tank (VCT) with gas for oxygen scavenging. Since the piping is directly connected to the VCT, the staff questioned whether the system should be considered within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2), because of the potential for physical interaction between the nonsafety- and safety-related equipment. The staff asked the applicant to evaluate placing the hydrogen system or nitrogen system, or both, within scope under 10 CFR 54.4(a)(2) and to evaluate any other interfaces of gas system interaction with safety-related equipment.

In its response, dated March 12, 2008, the applicant stated that the IP3 VCT is within scope and subject to an AMR, in accordance with 10 CFR 54.4(a)(1). The nitrogen system piping (and associated valve components) upstream of check valve 270 are within scope and subject to an AMR, in accordance with 10 CFR 54.4(a)(2), with component types evaluated in the LRA. In addition, the piping and valves connected to check valve 270 have an intended function to maintain integrity to ensure that physical interaction with safety-related components cannot prevent satisfactory accomplishment of a safety function due to structural support. Therefore, the hydrogen system should be within scope, as required by 10 CFR 54.4(a)(2). The applicant revised the LRA to include the hydrogen system. The applicant stated that no additional changes to the LRA were required due to other gas system interaction with safety-related equipment. The staff's concern described in RAI 2.2B-2 is resolved. SER Section 2.3B.3.19 documents the staff's review of the IP3 hydrogen system that the applicant added to the scope of license renewal. SER Section 3.3.2.1 documents the staff's evaluation of AMR results for the IP3 hydrogen system.

2.2B.4 Conclusion

The staff reviewed LRA Section 2.2, the RAI responses, and the UFSAR supporting information to determine whether the applicant failed to identify any systems and structures within the scope of license renewal. The staff identified the omission of the hydrogen system, which the applicant should have included within the scope of license renewal. The applicant has satisfactorily resolved this issue as discussed in the preceding staff evaluation. Therefore, on the basis of its review, the staff concludes that the applicant has appropriately identified the mechanical systems and structures within the scope of license renewal, as required by 10 CFR 54.4(a).

2.3 Scoping and Screening Results: Mechanical Systems

SER Section 2.3A presents the scoping and screening results for IP2 mechanical systems; SER Section 2.3B presents the scoping and screening results for IP3 mechanical systems.

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

- RCS
- engineered safety features
- auxiliary systems
- steam and power conversion systems

In accordance with the requirements of 10 CFR 54.21(a)(1), the applicant must identify and list passive, long-lived mechanical SSCs that are within the scope of license renewal and subject to an AMR. To verify that the applicant properly implemented its methodology, the staff focused its review on the implementation results. This focus allowed the staff to confirm that the applicant had not omitted any mechanical 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 mechanical systems. The objective was to determine whether the applicant had identified, as required by 10 CFR 54.4, components and supporting structures for mechanical 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 license renewal drawings, focusing on components that the applicant had not included within the scope of license renewal. The staff reviewed relevant licensing basis documents, including the UFSAR, for each mechanical system to determine whether the applicant had omitted from the scope of license renewal any components with license renewal intended functions, as defined in 10 CFR 54.4(a). The staff also reviewed the licensing basis documents to determine whether the LRA specified all license renewal intended functions in accordance with 10 CFR 54.4(a). The staff requested additional information to resolve any omissions or discrepancies identified.

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

Two-Tier Scoping Review Process for Balance of Plant Systems

The scope of license renewal as documented in the LRA, includes 144 mechanical systems, among which 96 systems are balance of plant (BOP) systems. These 96 systems include most of the auxiliary systems and all of the steam and power conversion systems. The staff performed a two-tier scoping review for these BOP systems.

In the two-tier scoping review, the staff reviewed the LRA and UFSAR description, focusing on the system intended function, and divided all of the BOP systems into two groups, those that required a simplified Tier 1 review and those that required a more detailed Tier 2 review. The staff selected the systems for a detailed Tier 2 review based on the following screening criteria:

- safety importance and risk significance
  - high safety-significant systems
  - common-cause failure of redundant trains
- operating experience indicating likely passive failures
- previous LRA review experience

Examples of systems that are typically selected for safety importance and risk significance, based on the individual plant examination results, are the component cooling water (CCW) system, the auxiliary feedwater (AFW) system, and the SW system. An example of a system, whose failure could cause failure of redundant trains is a drain system for flood protection. Examples of systems with operating experience that indicates the potential for passive failures include the main steam (MS), feedwater (FW), and SW systems. Examples of systems with omissions identified in previous LRA reviews include the spent fuel cooling system and makeup water sources to safety systems. In addition, the staff ensured that a minimum of 50 percent of the BOP systems received a Tier 2 review.

For systems receiving a simplified Tier 1 review, the staff reviewed the LRA and the UFSAR to determine whether the applicant failed to identify any component types typically found within the scope of license renewal. SER Sections 2.3A.3 and 2.3B.3 identify the IP2 and IP3 BOP systems, respectively, for which the staff conducted a simplified Tier 1 review. For all other BOP systems, the staff performed a detailed Tier 2 review.

For systems receiving a detailed Tier 2 review, the staff reviewed the LRA, UFSAR, and the detailed boundary drawings to determine whether the applicant failed to identify any components within the scope of license renewal and any components subject to an AMR. During its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant did not omit from the scope of license renewal any components with intended functions, as defined in 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 and long-lived components subject to an AMR, in accordance with 10 CFR 54.21(a)(1).

2.3A IP2 Scoping and Screening Results: Mechanical Systems

2.3A.1 Reactor Coolant System

LRA Section 2.3.1 identifies the RCS SCs subject to an AMR for license renewal.

The RCS includes mechanical components in the following subsystems.

- reactor vessel
- reactor vessel internals
- steam generators (SGs)
- RCPs
- pressurizer
- control rod drives
- in-core instrumentation

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

- 2.3.1.1, "Reactor Vessel"
- 2.3.1.2, "Reactor Vessel Internals"
- 2.3.1.3, "Reactor Coolant Pressure Boundary"
- 2.3.1.4, "Steam Generators"

LRA Section 2.3.1 describes the following RCS subsystems:

Reactor Vessel. The cylindrical reactor vessel has a hemispherical bottom and a flanged and gasketed removable upper head. The upper reactor closure head and the reactor vessel flange are joined by studs. Two metallic O-rings seal the reactor vessel when the reactor closure head is bolted in place. A leak-off connection between the two O-rings monitors leakage across the inner O-ring. The vessel design is in accordance with ASME Code, Section III, "Nuclear Vessels." Coolant enters the reactor vessel through inlet nozzles in a plane just below the vessel flange and above the core, flows downward through the annular space between the vessel wall and the core barrel into a plenum at the bottom of the vessel, reverses direction, and flows up through the core. After mixing in the upper plenum, the mixed coolant stream then flows out of the vessel through exit nozzles on the same plane as the inlet nozzles. The core instrumentation nozzles are on the lower head and the control rod nozzle penetrations are on the upper head.

Reactor Vessel Internals. The reactor vessel internals direct the coolant flow, support the reactor core, and guide the control rods. The reactor vessel contains the core support assembly, upper plenum assembly, fuel assemblies, control cluster assemblies, surveillance specimens, and in-core instrumentation. The lower core support structure, the upper core support structure, and the incore instrumentation support structure are the three major parts of the reactor vessel internals. A one-piece thermal shield, concentric with the reactor core, is located between the core barrel and the reactor vessel. The shield, cooled by the coolant on its downward pass, protects the vessel by attenuating much of the gamma radiation and some of the fast neutrons which escape from the core.

Pressurizer. System pressure is controlled by the pressurizer, which maintains water and steam pressure through the use of electrical heaters and sprays. Steam can either be formed by the heaters or condensed by a pressurizer spray to minimize pressure variations caused by contraction and expansion of the coolant. Control and protective circuits such as the high-pressure trip and code relief valves connected to the top head of the pressurizer protect the RCS against overpressure. The relief valves discharge into the pressurizer relief tank, which condenses and collects the valve effluent. Two power-operated relief valves (PORVs) and three code safety valves protect against pressure surges beyond the pressure-limiting capacity of the pressurizer spray. The PORVs also operate from the overpressure protection system to prevent RCS pressure from exceeding the limits of ASME Code, Section III, Appendix G during low-temperature operation. Steam and water discharge from the power relief and safety valves passes to the pressurizer relief tank partially filled with water at or near ambient containment conditions. The tank normally contains water in a predominantly nitrogen atmosphere. Steam discharged under the water level condenses and cools by mixing with the water. Rupture discs that discharge into the reactor containment protect the tank against a discharge exceeding the design value.

<u>Steam Generators</u>. Each reactor coolant loop has a vertical shell and U-tube steam generator (SG). Reactor coolant enters the inlet side of the channel head at the bottom of the SG through the inlet nozzle, flows through the U-tubes to an outlet channel, and exits the generator through another bottom nozzle. The inlet and outlet channels are separated by a partition. Feedwater to the SG enters just above the top of the U-tubes through a feedwater ring. The water flows downward through an annulus between the tube wrapper and the shell and then upward through the tube bundle where it converts to a steam-water mixture that passes through a primary separator assembly that reduces the water content in the mixture. The separated water combines with the feedwater for another pass through the tube bundle. The remaining higher steam-content mixture rises through additional secondary separators which further reduce the water content.

<u>Reactor Coolant Pumps</u>. Each reactor coolant loop has a vertical single-stage centrifugal pump with a controlled-leakage seal assembly. Reactor coolant pumped by the impeller attached to the bottom of the rotor shaft and drawn up through the impeller discharges through passages in the diffuser and out through a discharge nozzle in the side of the casing. A flywheel at the top of the rotor shaft extends the pump coastdown flow during any loss of power to the pump motor. A portion of the flow from the chemical and volume control system (CVCS) charging pumps is injected into the RCP between the impeller and the controlled-leakage seal. Component cooling water flows to the motor-bearing oil coolers and the thermal barrier cooling coil.

The RCS contains safety-related components relied on to remain functional during and following DBEs. The failure of nonsafety-related SSCs in the RCS potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the RCS performs functions that support fire protection, PTS, ATWS, and SBO.

<u>Control Rod Drives</u>. The control rod drive system positions the control rods within the core. The reactor uses the Westinghouse magnetic-type control rod drive assemblies on the upper reactor vessel head to insert or withdraw control rods in the core to control generation of nuclear power. The movement of the control rods is accomplished through the sequential operation of three types of magnetic coils. Upon a loss of power to the coils, the released rod cluster control assemblies with full-length absorber rods fall by gravity into the core. Each control rod drive assembly is a hermetically-sealed unit to prevent leakage of reactor coolant. The design of all pressure-containing components meets ASME Code, Section III, Division 1 requirements for Class A vessels.

The control rod drive system contains safety-related components relied upon to remain functional during and following DBEs.

In-Core Instrumentation. The in-core instrumentation system provides information on the neutron flux distribution and fuel assembly outlet temperatures at selected core locations to confirm reactor core design parameters and calculated hot channel factors. The system acquires data and performs no plant operation. The system consists of thermocouples positioned to measure fuel assembly coolant outlet temperature at preselected locations, flux thimbles running the length of selected fuel assemblies to measure the neutron flux distribution within the reactor core by moveable in-core detectors, in-core drives, drive motors, positioning equipment, and instruments. The flux thimbles, seal table, and guide tube form part of the RCPB. The in-core instrumentation system includes the pressure-retaining guide tubes that form parts of the RCPB. For IP2, the RCS and the nuclear instrumentation system include other, nonpressure boundary portions of the in-core instrumentation (listed in LRA Table 2.2-1b-IP2 with the electrical and I&C systems).

The in-core instrumentation system contains safety-related components relied upon to remain functional during and following DBEs.

The RCS Class I piping evaluation boundary extends into portions of systems attached to the RCS. For both units, the RCS AMR includes the Class I components of the systems listed below. The LRA section referenced below includes the non-Class 1 portions of the following systems:

- CVCS (LRA Section 2.3.3.6)
- isolation valve seal water (LRA Section 2.3.2.3)
- primary sampling system (LRA Section 2.3.3.19)
- residual heat removal (RHR) (LRA Section 2.3.2.1)
- safety injection system (LRA Section 2.3.2.4)

IP2 RCS components containing air are evaluated with compressed air systems (LRA Section 2.3.3.4). A small number of IP2 RCS components are evaluated with the primary water makeup systems (LRA Section 2.3.3.7) and the nitrogen systems (LRA Section 2.3.3.5). IP2 RCP lube oil collection system components are part of the IP2 fire protection system, not the RCS. IP2 RCS containment penetration components, which are not part of the RCPB, are evaluated with containment penetrations (LRA Section 2.3.2.5).

Fuel assemblies are not subject to an AMR because they are replaced after a limited number of fuel cycles. The control rods are active components and are not subject to an AMR.

SER Sections 2.3A.1.1–2.3A.1.4 discuss the staff's findings based on its review of LRA Sections 2.3.1.1–2.3.1.4, respectively.

2.3A.1.1 Reactor Vessel

2.3A.1.1.1 Summary of Technical Information in the Application

LRA Section 2.3.1.1 describes the reactor vessel, stating that the evaluation boundary for the reactor vessel encompasses the reactor vessel pressure boundary subcomponents, which include the shell, top and bottom heads, closure head stud assembly, primary nozzles and safe-ends, control rod drive mechanism (CRDM) housing penetrations, bottom-mounted instrumentation flux thimble tube penetrations, guide tubes, and seal table. LRA Section 2.3.1.1 also describes other subcomponents that support the intended functions of the reactor vessel, including the core support pads and core guide lugs, vessel flange, and closure head lifting lugs.

LRA Section 2.3.1 describes the functions of the reactor vessel. LRA Tables 2.3.1-1-IP2 and 2.3.1-1-IP3 identify reactor vessel component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.1.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.1 and the UFSARs using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

During its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant had not omitted from the scope of license renewal any components with intended functions, as require by 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 and long-lived components subject to an AMR, in accordance with 10 CFR 54.21(a)(1).

2.3A.1.1.3 Conclusion

The staff reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the reactor vessel 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).

2.3A.1.2 Reactor Vessel Internals

2.3A.1.2.1 Summary of Technical Information in the Application

LRA Section 2.3.1.2 describes the reactor vessel internals. For both units, the lower core support structure, the upper core support structure, and the incore instrumentation support structure are the three major parts of the reactor internals.

The lower core support structure is supported at its upper flange from a ledge in the reactor vessel. Within the core barrel are a core baffle and a lower core plate, both of which are attached to the core barrel wall. The lower core support structure provides passageways for the coolant flow. The lower core plate at the bottom of the core below the baffle plates provides support and orientation for the fuel assemblies. Fuel alignment pins (two for each assembly) are also inserted into this plate. Columns are placed between the lower core plate and core support casting to provide stiffness and to transmit the core load to the core support casting. Adequate coolant distribution is obtained through the use of the lower core plate and a diffuser plate.

The support columns establish the spacing between the upper support assembly and the upper core plate and are fastened at top and bottom to these plates and beams.

The rod cluster control assembly guide tube assemblies shield and guide the control rod drive shafts and control rods. They are fastened to the upper support and are guided by pins in the upper core plate for proper orientation and support. The control rod shroud tube, which is attached to the upper support plate and guide tube, provides additional guidance for the control rod drive shafts.

An upper system (thermocouple conduit) is used to convey and support thermocouples penetrating the vessel through the head, and a lower system (flux thimble guide tube) is used to convey and support flux thimbles penetrating the vessel through the bottom. The upper system utilizes the reactor vessel head penetrations. Instrumentation port columns are slip-connected to in-line columns that are in turn fastened to the upper support plate. These port columns protrude through the head penetrations. The thermocouples are carried through these port columns and the upper support plate at positions above their readout locations. The columns of the upper core support system support the thermocouple conduits.

LRA Section 2.3.1 describes the functions of the reactor vessel internals. LRA Tables 2.3.1-2-IP2 and 2.3.1-2-IP3 identify reactor vessel internals component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.1.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.2 and the UFSAR using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review, the staff identified an area in which additional information was necessary to complete its review. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3A.1.2-1, dated January 28, 2008, the staff noted that if certain reactor vessel internals failed, they could potentially inhibit core coolability during an accident. Therefore, the staff requested that the applicant clarify whether the sample tubing and sample tubing springs are within the scope of license renewal.

In its response, dated February 27, 2008, the applicant stated that it had evaluated the sample tubing (also known as the irradiation specimen guide) and the sample tubing springs (also known as the specimen plugs). The review included consideration of component functions and the potential impact of component failure on the function of other components. The applicant stated that sample tubing and the sample tubing springs have no license renewal intended function and are not subject to an AMR. Additionally, the applicant stated that it had reviewed Westinghouse Commercial Atomic Power (WCAP)-14577 Rev 1-A, "License Renewal Evaluation: Aging Management for Reactor Internals." Section 3.1 of the staff's SER, which evaluated WCAP-14577 states, "[t]he staff found the list of intended functions to be complete and in accordance with 10 CFR 54.4(a)." Section 2.1.1 of the same SER details the list of functions and states, "Prevent failure of all nonsafety-related systems, structures, and components whose failure could prevent any of these (previously listed) functions." WCAP-14577A, Table 2-2, confirms the applicant's conclusion that no AMR is required for the sample tubing and the sample tubing springs because the components do not have a license renewal function. Therefore, the staff finds the applicant's response acceptable. The staff's concern described in RAI 2.3A.1.2-1 is resolved.

2.3A.1.2.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI response to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the reactor vessel internals 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).

2.3A.1.3 Reactor Coolant Pressure Boundary

2.3A.1.3.1 Summary of Technical Information in the Application

LRA Section 2.3.1.3 describes the RCPB, which includes the pressurizer, RCPs, interconnecting piping and fittings, system valves, component bolting, and piping and valves from connected systems. The RCPB includes multiple components from interconnecting systems, since their safety function is to maintain the RCS pressure boundary integrity. RCPB piping consists of the primary loops to and from the reactor pressure vessel, SG, and RCPs. The main reactor coolant piping and fittings are austenitic stainless steel.

Smaller piping, including the pressurizer surge and spray lines, drains, and connections to other systems, is austenitic stainless steel. Piping connections are welded except for flanged connections at the pressurizer relief tank and at the relief and safety valves. LRA Section 2.3.1.3 provides a listing of the lines comprising the RCPB.

LRA Section 2.3.1 describes the functions of the RCPB.

LRA Tables 2.3.1-3-IP2, 2.3.3-19-30-IP2, 2.3.1-3-IP3, 2.3.3-19-43-IP3, 2.3.3-19-44-IP3, and 2.3.3-19-46-IP3 identify RCPB component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.1.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.3, the UFSARs, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review, the staff identified areas in which additional information was necessary to complete its review. The applicant responded to the staff's RAIs as discussed below.

In RAI 2.3A.1.3-1, dated November 9, 2007, the staff noted that License renewal drawing LRA-9321-2738, Sheet 1, depicts the RCPB for IP2. The staff was uncertain as to whether additional drawings depicting the RCPB existed. Therefore, the staff asked the applicant to clarify whether there were any additional sheets depicting the RCPB, and if so, to provide the drawings to the staff.

In its response, dated December 6, 2007, the applicant stated that License renewal drawing LRA-9321-2738 consisted of only one sheet, and the drawing, which identifies the major components in the RCS for IP2, includes the reactor vessel, pressurizer, RCPs, and SGs. The other License renewal drawings listed on page 2.3-20 of the LRA depict the remaining RCPB components for IP2 and IP3 that are in scope and subject to an AMR. License renewal drawing LRA-9321-2738 shows the continuations of lines to the other drawings depicting portions of the RCPB.

Based on its review, the staff finds the applicant's response acceptable because it clarified which drawings depict the components of the RCBP that are in scope and subject to an AMR. The response also confirmed that there were no additional drawings required staff review. Therefore the staff's concern in RAI 2.3A.1.3-1 is resolved.

In RAI 2.3A.1.3-2, dated January 28, 2008, the staff requested that the applicant clarify whether the pressurizer manways are within the scope of license renewal and subject to an AMR. LRA Tables 2.3.1-3-IP2 and 2.3.1-3-IP3 identified the pressurizer manway covers and insert plates as within the scope of license renewal and subject to an AMR.
.
In its response, dated February 27, 2008, the applicant stated that the pressurizer manway is a ring, integral to the shell of the pressurizer. The manway is part of the pressurizer shell included within the "pressurizer shell and heads" entries in LRA Tables 2.3.1-3-IP2 and 2.3.1-3-IP3. All portions of the manway assembly (i.e., the manway cover, the manway insert plate, and the pressurizer shell including the manway itself) are within the scope of license renewal and subject to AMR. Because the applicant clarified that this component is already within the scope of license renewal, the staff finds the applicant's response acceptable. The staff's concern described in RAI 2.3A.1.3-2 is resolved.

In RAI 2.3A.1.3-3, dated January 28, 2008, the staff requested that the applicant provide additional information and, if necessary, justify the exclusion of the vents associated with the level sensors, as shown on license renewal drawing LRA-208798-0. The applicant did not highlight the level sensor vents in the reactor vessel level indication system as components that are subject to an AMR. The sensor vents appear to provide an RCPB.

In its response, dated February 27, 2008, the applicant stated that the level elements on drawing LRA-208798, LE-1311, LE-1312, LE-1321 and LE-1322, are pressure transmitters. The vents are part of the transmitter body. In accordance with 10 CFR 54.21(a)(1)(i) and NEI 95-10, pressure transmitters are active components that are not subject to an AMR. Normal operational and surveillance activities readily monitor the performance or condition of active components.

Because this component is part of an active component and is monitored through normal operational activities, the staff finds the applicant's response acceptable. The staff's concern described in RAI 2.3A.1.3-3 is resolved.

In RAI 2.3.0-2, dated February 13, 2008, the staff noted that on license renewal drawings for the IP2 and IP3 RCP motors, various components of the upper and lower bearing heat exchangers were marked "Not A Long Lived Component," and thus, were not subject to an AMR. Additionally, the staff noted that license renewal drawings of the IP2 and IP3 emergency diesel generator (EDG) jacket water cooling systems also have components marked "Not A Long Lived Component." The staff noted that SRP-LR Section 2.1.3.2.2 describes long-lived SCs as those that are not subject to periodic replacement based on a qualified life or specified time period. Furthermore, this section states that replacement programs may be based on vendor recommendations, plant experience, or any means that establishes a specific replacement frequency under a controlled program.

Because the staff identified that previous LRAs typically have not designated pumps, motors, and heat exchangers as "not long lived" (i.e., these components, or portions thereof, are subject to an AMR), the staff requested the applicant to:

(a) Identify the component types serviced by the CCW system indicated in the above mentioned drawings that are marked "Not A Long Lived Component."

(b) Provide a basis for designating these components as "not long lived" to include details on how the "qualified life" of the components was established and describe the program under which aging management activities for the components are performed and any available plant-specific operating experience confirming the effectiveness of management activities.

In its response, dated March 12, 2008, the applicant addressed the staff's concerns for the component types serviced by the CCW system. The applicant stated that it reviewed the documentation specifying the RCP motor upper and lower bearing heat exchangers as short lived and determined that they are actually not subject to periodic replacement. The applicant stated that the RCP motor upper and lower bearing heat exchangers are therefore subject to an AMR. Additionally, in its response, the applicant proposed changes to LRA Section 3.3.2.1.3 and LRA Tables 3.3.2-3-IP2 and 3.3.2-3-IP3 for the CCW system to include the aforementioned heat exchangers with their materials, environments, and aging management programs (AMPs). SER Section 3.3.2.1 documents the staff's review of the AMR line items. SER Sections 2.3A.3.14 and 2.3B.3.14 document the staff's evaluation of the applicant's response for the EDG jacket water cooling system.

Based on its review, the staff finds the applicant's response to RAI 2.3.0-2 acceptable for the RCS because it adequately explained that the RCP motor upper and lower bearing cooler heat exchangers in the CCW system were erroneously designated "Not A Long-Lived Component" and are, therefore, subject to an AMR. Further, in its March 12, 2008, letter, the applicant amended the LRA to include the heat exchangers and their AMP. Therefore, the staff's concern described in RAI 2.3.0-2 is resolved.

2.3A.1.3.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found an instance in which the applicant omitted components that should have been subject to an AMR. The applicant has satisfactorily resolved this issue as discussed in the preceding staff evaluation. On the basis of its review, the staff concludes that the applicant has adequately identified the RCPB 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).

2.3A.1.4 Steam Generators

2.3A.1.4.1 Summary of Technical Information in the Application

The SGs are designed and manufactured in accordance with ASME Code, Section III. The IP2 SGs were constructed in accordance with the 1980 Edition, through the Winter 1981 Addenda, of the ASME Code. The IP3 SGs were constructed consistent with the 1983 Edition, through the Summer 1984 Addenda, of the ASME Code. The SGs are constructed primarily of carbon (low alloy) steel. The heat transfer tubes are Inconel: Alloy 600 for IP2 and Alloy 690 for IP3. The tubes were thermally treated after tube-forming operations. The interior surfaces of the channel heads and nozzles are clad with austenitic stainless steel, and the tubesheet surfaces in contact with reactor coolant are clad with Inconel. The tube-to-tubesheet joints are welded. The primary nozzles are provided with safe-ends with weld metal overlay.

LRA Section 2.3.1 describes the functions of the SGs. LRA Tables 2.3.1-4-IP2 and 2.3.1-4-IP3 identify SG component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

LRA Section 2.3.1 describes the functions of the SGs. LRA Tables 2.3.1-4-IP2 and 2.3.1-4-IP3 identify SG component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.1.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.4, the UFSARs, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3A.1.4.3 Conclusion

The staff reviewed the LRA, UFSAR, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff determined whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the SG 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).

2.3A.2 Engineered Safety Features

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

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

- 2.3.2.1, “Residual Heat Removal”
- 2.3.2.2, “Containment Spray System”
- 2.3.2.3, “Containment Isolation Support Systems”
- 2.3.2.4, “Safety Injection Systems”
- 2.3.2.5, “Containment Penetrations”

SER Sections 2.3A.2.1–2.3A.2.5 discuss the findings of the staff’s review of LRA Sections 2.3.2.1–2.3.2.5, respectively.

2.3A.2.1 IP2 Residual Heat Removal

2.3A.2.1.1 Summary of Technical Information in the Application

LRA Section 2.3.2.1 describes the RHR system, which provides emergency core cooling, as part of the safety injection system, and removes residual heat during later stages of plant cooldown. The RHR system is one of three (RHR, CCW, and spent fuel pit cooling (SFPC)) auxiliary coolant systems. The RHR system consists of two RHR heat exchangers, two seal coolers, two RHR (low-head) pumps, and required piping, valves, and I&C components. The RHR system provides emergency core cooling during the injection phase of a loss-of-coolant accident (LOCA). The RHR heat exchangers, in conjunction with the safety injection recirculation pumps, are used for post-accident heat removal during the LOCA recirculation phase. Outlet flow from the RHR heat exchangers may be directed to the containment spray (CS) headers, to the RCS cold legs, or to the RCS hot legs via the high-head safety injection pumps. The RHR pumps also back up the safety injection system recirculation pumps during a LOCA recirculation phase. In this capacity, the RHR pumps may draw water from the containment sump and deliver it to the RCS cold leg injection lines, to the suction of the high-head safety injection pumps, or to the CS headers. The RHR system removes residual heat during the later stages of plant cooldown and during cold shutdown and refueling operations. After RCS temperature and pressure have been reduced to 350 degrees F and less than 365 pounds per square inch gauge (psig), alignment of the RHR pumps initiates decay heat cooling by taking suction from one reactor hot leg and discharging it through the RHR heat exchangers into the reactor cold legs.

The RHR system contains safety-related components relied on to remain functional during and following DBEs. In addition, the RHR system performs functions that support fire protection and SBO.

In the LRA, ASME Code Class 1 components with the intended function of maintaining the RCPB are reviewed with the RCS (LRA Section 2.3.1). A small number of components are reviewed with the safety injection system in LRA Section 2.3.2.4.

LRA Table 2.3.2-1-IP2 identifies RHR system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.2.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.1, the UFSAR, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3A.2.1.3 Conclusion

The staff reviewed the LRA, UFSAR, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the RHR system 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).

2.3A.2.2 IP2 Containment Spray System

2.3A.2.2.1 Summary of Technical Information in the Application

LRA Section 2.3.2.2 describes the CS system, which cools the containment and removes iodine following an accident. The CS system consists of two trains of pumps, valves, and headers that automatically start and spray refueling water storage tank (RWST) borated water into the containment atmosphere when the system senses high containment pressure following a LOCA or MS line break accident. The spray water enters through nozzles connected to four ring headers in the containment dome. Each spray pump supplies two ring headers. After injection from the RWST is terminated, the system can supply the spray headers with recirculated water from the recirculation sump or the containment sump by a diversion of a portion of the injection flow from the safety injection system. Long-term, post-accident retention of iodine is achieved by four sodium tetraborate baskets in the containment at an elevation (46 feet) that will be flooded under accident conditions, allowing the sodium tetraborate to dissolve into the fluid for pH control. The containment structural evaluation includes the four sodium tetraborate baskets, but they are not described further because they have no license renewal intended function and are therefore not subject to an AMR.

The CS system contains safety-related components relied on to remain functional during and following DBEs.

Containment spray system components that support the RHR system pressure boundary are reviewed in the RHR systems (LRA Section 2.3.2.1). A small number of components are reviewed in the safety injection system (LRA Section 2.3.2.4).

LRA Table 2.3.2-2-IP2 and newly created Table 2.3.3-19-46-IP2 (see evaluation below) identify CS system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.2.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.2, UFSAR Section 6.3, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.2.2, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results.

During its review of license renewal drawings for the containment spray system, the staff identified portions of piping of the CS system that were not highlighted, indicating that section of piping had no intended functions in accordance with 10 CFR 54.4 (a)(1) or 10 CFR 54.4 (a)(3). LRA Section 2.3.2.2 states that the CS system has no intended function for 10 CFR 54.4(a)(2). However, this section of piping is directly connected to safety-related containment spray piping; therefore, the staff determined that it should be in scope for 10 CFR 54.4(a)(2) for nonsafety-related piping that is structurally attached to safety-related piping. In RAI 2.3A.2.2-1, dated February 13, 2008, the staff asked the applicant to explain this discrepancy. The staff also asked the applicant to indicate any portions of the CS system evaluated for inclusion in the scope of license renewal in accordance with 10 CFR 54.4(a)(2), and to identify any other instances whereby a system was identified as not having any 10 CFR 54.4(a)(2) function but did have nonsafety-related components that were not identified as within scope for 10 CFR 54.4(a)(2).

In its response, dated March 12, 2008, the applicant stated that the components identified by the staff do have an intended function to maintain integrity such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function. Hence, the applicant amended the LRA to include the portions of the CS system within the scope of license renewal under the requirements of 10 CFR 54.4(a)(2). The applicant responded to the staff's request by performing a re-evaluation of those safety-related systems that were identified in the LRA as only being in scope for (a)(1) and have no (a)(2) components. The applicant's re-examination identified three instances where a system that performs a safety function was in scope for 10 CFR 54.4(a)(1), but nonsafety-related components were not identified as in scope for 10 CFR 54.4(a)(2). The staff's evaluation of the affected systems is discussed in SER Sections 2.3A.3.3, 2.3B.2.5, and 2.3B.3.3. For the IP2 CS system, in its letter dated March 12, 2008, the applicant amended the LRA to reflect the following changes:

(a) LRA Table 2.3.3-19-A-IP2 would reflect the CS system as a miscellaneous system within the scope of license renewal for 10 CFR 54.4(a)(2).

(b) Removal of the CS system from the list of IP2 systems not reviewed for 10 CFR 54.4(a)(2) for spatial interaction.

(c) Revision of LRA Table 2.3.3-19-B-IP2 to reflect that the CS system now has components subject to an AMR for 10 CFR 54.4(a)(2).

(d) Creation of a new LRA Table 2.3.3-19-46-IP2 for the five added component types in the CS system for nonsafety-related components potentially affecting a safety function, and subject to an AMR.

(e) Creation of a new LRA Table 3.3.2-19-46-IP2 for the five added component types, their materials, environments, and AMPs.

Based on its review, the staff finds the applicant's response to RAI 2.3A.2.2-1 for the IP2 CS system acceptable because it adequately explained that the applicant's reevaluation of safety-related systems identified components that should have been within scope under 10 CFR 54.4(a)(2). Additionally, the applicant amended the LRA to include those portions of the CS system identified by the staff as being in scope under 10 CFR 54.4(a)(2). The staff reviewed the applicant's changes to the LRA tables and found that they adequately reflect those components brought into the scope of license renewal, in accordance with 10 CFR 54.4(a)(2), because of their potential for spatial interaction with safety-related components. Therefore, the staff's concern described in RAI 2.3A.2.2-1 for the CS system is resolved. SER Section 3.2.2.1 documents the staff's evaluation of new AMR results for the CS system.

2.3A.2.2.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found one instance in which the applicant omitted components that should have been subject to an AMR. The applicant has satisfactorily resolved this issue as discussed in the preceding staff evaluation. On the basis of its review, the staff concludes that the applicant has adequately identified the CS system 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).

2.3A.2.3 IP2 Containment Isolation Support Systems

2.3A.2.3.1 Summary of Technical Information in the Application

LRA Section 2.3.2.3 describes the containment isolation support systems, which include the isolation valve seal water systems and the weld channel and penetration pressurization system. The containment isolation support systems consist of piping and valves routed to the various system piping that penetrates the containment. The isolation valve seal water, weld channel, and penetration pressurization systems isolate the containment from the outside environment for various systems with piping penetrating containment. The containment isolation support systems inject fluid or air or gas into system lines between the containment isolation valves that penetrate the containment for pressure boundary integrity against leakage of radioactive fluids to the environment in the event of a LOCA. Individual lines define these barriers of piping and isolation valves systems. Besides satisfying containment isolation criteria, the valving facilitates normal operation and maintenance of the systems for reliable operation of other engineered safeguard systems.

The isolation valve seal water system provides sealing water or gas between the isolation and double-disk isolation valves of containment penetrations located in lines connected to the RCS or exposed to the containment atmosphere during any condition that requires containment isolation. This system limits fission product release from the containment. Although not credited in post-accident dose analyses, the system ensures a containment leak rate in an accident lower than that assumed in the accident analysis and the offsite dose calculations. System components form parts of the containment penetration isolation boundary.

The weld channel and penetration pressurization system provides pressurized gas to all containment penetrations and most liner inner weld seams in the event of a LOCA, so there will be no leakage through these potential paths from the containment to the atmosphere. The weld channel and penetration pressurization system also serves spaces between selected isolation valves. Although not credited in the post-accident dose analyses, the weld channel and penetration pressurization system maintained at a pressure level above the peak accident pressure is designed to keep any postulated leakage in rather than out of the containment. The system supplies regulated clean, dry compressed air from either of the plant's compressed air systems outside the containment to all containment penetrations and most inner liner weld channels. The instrument air system, backed up by the station air system and by a bank of nitrogen cylinders as a standby source of gas pressure, is the primary source of air for this system.

The containment isolation support systems contain safety-related components relied upon to remain functional during and following DBEs.

Isolation valve seal water system components with the intended function of maintaining the RCPB are reviewed in the RCS (LRA Section 2.3.1.3).

LRA Table 2.3.2-3-IP2 identifies containment isolation support systems component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.2.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.3, UFSAR Sections 6.5.1, 6.6.2, and 14.3.6.1, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During 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.

In RAI 2.3A.2.3-1, dated November 9, 2007, the staff identified several line-mounted components (valves PRV PCV 1193 through PRV PCV 1200) that were located in lines with a pressure boundary function. However, the applicant had not identified the components themselves as being subject to an AMR. Therefore, the staff requested that the applicant clarify whether these components are subject to an AMR or justify their exclusion.

In its response, dated December 6, 2007, the applicant stated that the valves in question are within the scope of license renewal and subject to an AMR. Furthermore, the applicant noted that LRA Table 2.3.2-3-IP2 identified these valves as component type “valve body,” with AMR results summarized in LRA Table 3.2.2-3-IP2. Some of the valves in question have aluminum valve bodies with internal and external environments of gas (internal) and air—indoor (external). The applicant added a line item of “valve body” to LRA Table 3.2.2-3-IP2 to reflect the aluminum material.

Based on its review, the staff finds the applicant’s response to RAI 2.3A.2.3-1 acceptable because the applicant clarified that the subject valves are within the scope of license renewal and subject to an AMR and added aluminum valve bodies to the AMR. The staff’s concern described in RAI 2.3A.2.3-1 is resolved. SER Section 3.2.2.1 discusses the staff’s evaluation of the added AMR for aluminum valve bodies.

By letter dated June 30, 2009, the applicant submitted an annual update to the LRA, identifying changes made to the CLB that materially affect the contents of the LRA. For the containment isolation support system, the applicant identified buried piping in the containment isolation support system that had not been previously identified as being within the scope of license renewal . The piping is part of the air pressure supply that feeds Rack 15 for the steam and feedwater penetrations shown on license renewal drawing LRA-9321-2726-0. The staff reviewed the amendment and finds the addition to the scope to be acceptable. The staff’s evaluation of the corresponding AMR results is documented in SER Section 3.2.2.1.

2.3A.2.3.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found one instance in which the applicant omitted components that should have been subject to an AMR. The applicant has satisfactorily resolved this issue as discussed in the preceding staff evaluation. On the basis of its review, the staff concludes that the applicant has adequately identified the containment isolation support 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).

2.3A.2.4 IP2 Safety Injection System

2.3A.2.4.1 Summary of Technical Information in the Application

LRA Section 2.3.2.4 describes the safety injection system, which, in a LOCA, automatically delivers cooling water to the reactor core to limit the fuel clad temperature so the core remains intact and in place with its essential heat transfer geometry preserved. Components comprising the safety injection system code (i.e., the applicant’s code for designating systems and boundaries) include the RWST, the three safety injection (high-head) pumps, the accumulators (one for each reactor coolant loop), recirculation pumps and piping, valves, and other components of these subsystems. The three safety injection (high-head) pumps inject RWST borated water into the RCS for core cooling. The safety injection signal automatically opens the required safety injection system isolation valves and starts the safety injection pumps. The injection piping and valves connect the accumulators containing borated water and pressurized with nitrogen to the RCS. Two check valves isolate these tanks from the RCS during normal operation. When RCS pressure falls below accumulator pressure the check valves open, discharging the tank contents into the RCS through the same injection piping used by the safety injection pumps.

After the injection, the recirculation system cools and returns to the RCS any coolant spilled from the break and water collected from the CS. The system recirculation pumps take suction from the recirculation sump in the containment floor and deliver spilled reactor coolant and borated refueling water back to the core through the RHR heat exchangers. For smaller RCS breaks in which recirculated water must be injected against higher pressures for long-term cooling, the system delivers the water from an RHR heat exchanger to the high-head safety injection pump suction and, by this external recirculation route, to the reactor coolant loops. The system also allows either of the RHR pumps to take over the recirculation function.

The safety injection system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the safety injection system performs functions that support fire protection.

ASME Code Class 1 components with the intended function of maintaining the RCPB are reviewed in the RCS (LRA Section 2.3.1.3). A small number of components are reviewed in the containment system (LRA Section 2.3.2.2), RHR systems (LRA Section 2.3.2.1), and nitrogen systems (LRA Section 2.3.3.5).

LRA Tables 2.3.2-4-IP2 and 2.3.3-19-37-IP2 identify safety injection system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.2.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.4, the UFSAR, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3A.2.4.3 Conclusion

The staff reviewed the LRA, UFSAR, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the safety injection system 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).

2.3A.2.5 IP2 Containment Penetrations

2.3A.2.5.1 Summary of Technical Information in the Application

LRA Section 2.3.2.5 describes the following containment penetrations, which are not an independent system but a grouping of containment penetration components that are not evaluated with other systems:

- electrical penetrations
- fuel core component handling system
- hydrogen recombiners

The electrical penetrations pass electrical conductors through the containment boundary. The electrical penetrations system code (i.e., the applicant's code for designating systems and boundaries) is primarily structural and electrical components that are evaluated in the structural and electrical AMRs; however, the system has mechanical components which are evaluated in this section. The penetrations have a pressure connection for continuous pressurization by the weld channel system, which is considered part of the containment isolation boundary.

The fuel core component handling system defuels and refuels the reactor core. The fuel handling system transports and handles fuel safely and effectively. Most system components (*e.g.*, fuel handling bridges) are structural and evaluated with their respective structures. The fuel transfer tube and blind flange are fuel core component handling system components that together constitute a containment penetration.

The hydrogen recombiners system, which reduces the hydrogen concentration in the containment volume following a DBA, has two redundant passive autocatalytic recombiners that replaced earlier flame units. The recombiners are passive devices with no moving parts and need no electrical power or any other support system. Recombination is by attraction of oxygen and hydrogen molecules to the surface of a palladium catalyst. The exothermic reaction of the combination generates heat, which causes a convective flow that draws more gases from the containment atmosphere into the unit. Since a recent license amendment (Amendment No. 243), hydrogen recombination is no longer required as a safety function. The system includes containment penetrations from the original flame hydrogen recombiners.

The containment penetrations contain safety-related components relied on to remain functional during and following DBEs.

Containment penetration components evaluated in this section maintain the system pressure boundary inside containment from the first weld from the penetration to the class boundary change outside containment. Components in the Class 1 boundary are reviewed in the RCPB (LRA Section 2.3.1.3). Structural portions of the containment penetrations are evaluated with the containment building (LRA Section 2.4.1). Electrical portions of electrical penetration assemblies are evaluated with electrical components (LRA Section 2.5).

LRA Table 2.3.2-5-IP2 identifies containment penetrations component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.2.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.5; UFSAR Sections 5.1.4, 5.1.4.2.1, 6.8, and 9.5.2; and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3A.2.5, the staff identified an area in which additional information was necessary to complete the review of the results of the applicant's scoping and screening effort. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3A.2.5-1, dated November 9, 2007, the staff noted that a drawing referenced for IP2 appeared to be applicable to IP3. Therefore, the staff requested that the applicant confirm the accuracy of the referenced drawings.

In its response, dated December 6, 2007, the applicant stated that an administrative error occurred when transferring the License renewal drawing numbers from the site basis document to the License renewal drawing list. Additionally, the applicant identified the drawings that corresponded to the respective units.

Based on its review, the staff found the applicant's response to RAI 2.3A.2.5-1 acceptable because the applicant identified and corrected an administrative error. Subsequently, the staff reviewed and evaluated the components associated with the containment penetrations on the referenced drawings and found no omissions from the scope of license renewal. The staff's concern described in RAI 2.3A.2.5-1 is resolved.

2.3A.2.5.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the containment penetrations 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).

2.3A.3 Scoping and Screening Results: IP2 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:

- 2.3.3.1, “Spent Fuel Pit Cooling“
- 2.3.3.2, “Service Water“
- 2.3.3.3, “Component Cooling Water“
- 2.3.3.4, “Compressed Air“
- 2.3.3.5, “Nitrogen Systems”
- 2.3.3.6, “Chemical and Volume Control“
- 2.3.3.7, “Primary Water Makeup“
- 2.3.3.8, “Heating, Ventilation and Air Conditioning“
- 2.3.3.9, “Containment Cooling and Filtration”
- 2.3.3.10, “Control Room Heating, Ventilation and Cooling”
- 2.3.3.11, “Fire Protection – Water”
- 2.3.3.12, “Fire Protection – CO_2, Halon, and RCP Oil Collection Systems”
- 2.3.3.13, “Fuel Oil”
- 2.3.3.14, “Emergency Diesel Generators”
- 2.3.3.15, “Security Generators”
- 2.3.3.16, “Appendix R Diesel Generators”
- 2.3.3.17, “City Water”
- 2.3.3.18, “Plant Drains”
- 2.3.3.19, “Miscellaneous Systems In-Scope for (a)(2)”

The applicant developed LRA Section 2.3.3.19 to capture all the systems or portions of systems that are within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). Among the subsections included in LRA Section 2.3.3.19, the staff identified the following auxiliary systems for simplified Tier 1 review:

- chemical feed
- intake structure system
- house service boiler
- main generator
- ignition oil
- integrated liquid waste handling
- nuclear service grade makeup
- boiler blowdown
- secondary sampling
- technical support center diesel
- main turbine

The staff conducted a more detailed Tier 2 review for all remaining auxiliary systems.

Staff Requests for Additional Information

During its review, the staff noted the applicant did not specifically identify components in scope under 10 CFR 54.4(a)(2) on the accompanied drawings. To ensure that the applicant did not omit any components that should be in scope under 10 CFR 54.4(a)(2), the staff asked the applicant to verify that it had included segments of the selected systems in scope under 10 CFR 54.4(a)(2). In the following RAIs, dated February 13, 2008, the staff requested that the applicant confirm its methodology for identifying nonsafety-related portions of systems with a potential to adversely affect safety-related functions by describing the applicable specific portions of system piping that the applicant included within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2):

- RAI 2.3A.3.1-1
- RAI 2.3A.3.2-1
- RAI 2.3A.3.3-1
- RAI 2.3A.3.5-1
- RAI 2.3A.3.13-1
- RAI 2.3A.3.14-2
- RAI 2.3A.3.18-1

In its response, dated March 12, 2008, the applicant stated that all component types identified by the staff on the license renewal drawings in question are within the scope of license renewal in accordance with 10 CFR 54.4(a)(2), and are subject to an AMR.

Based on its review, the staff finds the applicant’s response to these RAIs acceptable because the applicant has adequately explained that all component types identified by the staff are within the scope of license renewal in accordance with 10 CFR 54.4(a)(2) and are subject to an AMR. The staff’s concern described in these RAIs is resolved.

SER Sections 2.3A.3.1 through 2.3A.3.19 provide the staff’s reviews of IP2 systems described in LRA Sections 2.3.3.1 through 2.3.3.19, respectively. The following sections discuss the staff’s findings for these systems.

2.3A.3.1 IP2 Spent Fuel Pit Cooling System

2.3A.3.1.1 Summary of Technical Information in the Application

LRA Section 2.3.3.1 describes the SFPC system, which removes residual heat from the spent fuel pit. The SFPC loop has two pumps, a heat exchanger, filter, demineralizer, piping, valves, and instrumentation. One of the pumps draws water from the pit, circulates it through the heat exchanger cooled by CCW, and returns it to the pit. Loop piping is arranged so that any pipeline failure does not drain the spent fuel pit below the top of the stored fuel elements. The spent fuel pit pump suction line, which draws water from the pit, penetrates the spent fuel pit wall above the fuel assemblies. The system also includes the spent fuel pit. Spent fuel storage racks at the bottom of the pit for spent fuel assemblies are the full-length, top-entry type made of stainless steel with Boraflex as a neutron absorber.

The SFPC system contains safety-related components relied upon to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function.

The spent fuel pit (including liner and the spent fuel racks) are included in the evaluation of the fuel storage buildings (LRA Section 2.4.3). The heat exchanger components forming parts of the CCW system pressure boundary are evaluated with the CCW systems (LRA Section 2.3.3.3). A small number of components are evaluated with the primary water makeup systems (LRA Section 2.3.3.7).

LRA Tables 2.3.3-1-IP2 and 2.3.3-19-35-IP2 identify the SFPC system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.3.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.1; UFSAR Sections 9.3.1, 9.5.2.1.5, and 14.2.1; a license renewal drawing; and IP2 Amendment 227, “Credit for Soluble Boron and Burnup in Spent Fuel Pit (TAC No. MB2989),” dated May 29, 2002 (ADAMS Accession No. ML021230367), using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.3.1, the staff identified an area in which additional information was necessary to complete the review of the applicant’s scoping and screening results. The discussion of the staff’s RAIs in SER Section 2.3A.3 details the disposition of RAI 2.3A.3.1-1, dated February 13, 2008.

2.3A.3.1.3 Conclusion

The staff reviewed the LRA, UFSAR, and a drawing to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the SFPC 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).

2.3A.3.2 IP2 Service Water System

2.3A.3.2.1 Summary of Technical Information in the Application

LRA Section 2.3.3.2 describes the SW system, which supplies cooling water from the Hudson River to various heat loads in both primary and secondary portions of the plant, in a continuous flow to systems and components necessary for plant safety during either normal operation or abnormal or accident conditions. Sufficient redundancy of active and passive components maintains short- and long-term cooling to vital loads, in accordance with the single-failure criterion. Six identical vertical, centrifugal sump-type pumps at the intake structure supply service water to two independent discharge headers (each is supplied by three pumps). An automatic, self-cleaning, rotary-type strainer in each pump’s discharge removes solids. Each header connects to an independent supply line. Either of the two supply lines can supply the essential load, while the other supplies the nonessential load. Essential loads must have an assured supply of cooling water in the event of a loss of offsite power or a LOCA. Nonessential loads are supplied with cooling water by an SW pump started manually, when required, following a LOCA. Nonessential loads include the CCW heat exchangers, circulating water (CW) pump seal injection, turbine building closed cooling water system, hydrogen coolers, stator cooling water heat exchanger, exciter air coolers, and isolated phase bus heat exchangers. The system also provides backup water to clean the traveling screens.

The SW system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the SW system performs functions that support fire protection and SBO.

Components that support safe shutdown in the event of a fire in the auxiliary feed pump room are reviewed in LRA Section 2.3.4.5. Components cooling the CCW systems are reviewed in those systems (LRA Section 2.3.3.3). Components cooling the EDG systems are reviewed with those systems (LRA Section 2.3.3.14).

LRA Tables 2.3.3-2-IP2 and 2.3.3-19-39-IP2 identify SW system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.3.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.2, UFSAR Section 9.6.1, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.3.2, the staff identified an area in which additional information was necessary to complete the review of the applicant’s scoping and screening results. The discussion of the staff’s RAIs in SER Section 2.3A.3 details the disposition of RAI 2.3A.3.2-1, dated February 13, 2008.

2.3A.3.2.3 Conclusion

The staff reviewed the LRA, UFSAR, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has appropriately identified the SW system 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).

2.3A.3.3 IP2 Component Cooling Water System

2.3A.3.3.1 Summary of Technical Information in the Application

LRA Section 2.3.3.3 describes the CCW system, which removes RCS residual and sensible heat via the RHR loop during plant shutdown, cools the letdown flow to the CVCS during power operation, dissipates waste heat from various primary plant components, and cools engineered safeguards and safe-shutdown components. The system includes the pumps, heat exchangers, distribution and return piping and valves, instruments, and controls to cool the following:

- RHR heat exchangers
- RCPs
- non-regenerative heat exchanger
- excess letdown heat exchanger
- CVCS seal water heat exchanger
- sample heat exchangers
- waste gas compressors
- reactor vessel support pads
- RHR pumps
- safety injection pumps
- recirculation pumps
- spent fuel pit heat exchanger
- charging pumps, fluid drive coolers, and crankcase

Some of the CCW-cooled heat exchangers in other systems have no safety function; however, these nonsafety-related heat exchangers form parts of the CCW system pressure boundary. These heat exchangers are within the scope of license renewal and have an intended function to maintain the pressure boundary but not to transfer heat.

The CCW system was not designed to accommodate a passive failure during initial IP2 construction. The subsequent consideration of a passive failure required commitments for alternate cooling water supplies to safety-related equipment. Connections to primary and city water provide the alternate supplies.

The CCW system contains safety-related components relied on to remain functional during and following DBEs. In addition, the CCW system performs functions that support fire protection and SBO.

A few components within the CCW system support the RHR system pressure boundary and therefore are reviewed with the RHR systems (LRA Section 2.3.2.1). Components cooling the safety injection systems are reviewed with those systems (LRA Section 2.3.2.4). Components cooling the CVCS systems are reviewed with those systems (LRA Section 2.3.3.6).

LRA Table 2.3.3-3-IP2 and newly created Table 2.3.3-19-45-IP2 (see evaluation below) identify CCW system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.3.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.3, UFSAR Sections 6.2.2.3.4 and 9.3, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During 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.

In RAI 2.3A.2.2-1, dated February 13, 2008, the staff asked the applicant to identify instances in which a safety-related system, which has nonsafety-related components, was scoped in per 10 CFR 54.4(a)(1), but those nonsafety-related components were not identified as in scope for 10 CFR 54.4(a)(2).

In its response, dated March 12, 2008, the applicant explained that it identified three instances in which nonsafety-related components were not considered to be within the scope of license renewal under 10 CFR 54.4(a)(2). The applicant further explained that it should have included the CCW systems at IP2 and IP3, as well as the IP3 building vent sampling (BVS) system, among those systems subject to the requirements of 10 CFR 54.4(a)(2). In these instances, the applicant amended the LRA to reflect these changes. For the IP2 CCW system, in its letter dated March 12, 2008, the applicant amended the LRA to reflect the following changes:

(a) LRA Table 2.3.3-19-A-IP2 would reflect the CCW system as a miscellaneous system within the scope of license renewal pursuant to 10 CFR 54.4(a)(2).

(b) Removal of the CCW system from the list of IP2 systems not reviewed for spatial interaction, in accordance with 10 CFR 54.4(a)(2).

(c) Revision of LRA Table 2.3.3-19-B-IP2 to reflect that the CCW system now has components subject to an AMR, pursuant to 10 CFR 54.4(a)(2).

(d) Creation of a new LRA Table 2.3.3-19-45-IP2 for the five added component types in the CCW system for nonsafety-related components, potentially affecting a safety-related function, and subject to an AMR.

(e) Creation of a new LRA Table 3.3.2-19-45-IP2 for the five added component types, their materials, environments, and AMPs.

Based on its review, the staff finds the applicant's response to RAI 2.3A.2.2-1 for the IP2 CCW system acceptable because it adequately explained that the applicant's reevaluation of safety-related systems identified some components that should have been within scope for meeting the requirements of 10 CFR 54.4(a)(2). Additionally, the staff finds that the applicant's response amended the LRA to include those portions of the CCW system identified by the staff as being in scope under 10 CFR 54.4(a)(2). The staff reviewed the applicant's addition of new tables to the LRA and found that they adequately reflect those components brought into the scope of license renewal under 10 CFR 54.4(a)(2) because of their potential for spatial interaction with safety-related components. The staff's concern described in RAI 2.3A.2.2-1 for the IP2 CCW system is resolved. SER Section 3.3.2.1 documents the staff's evaluation of new AMR results for the CCW system.

The discussion of the staff's RAIs in SER Section 2.3A.3 details the disposition of RAI 2.3A.3.3-1, dated February 13, 2008.

2.3A.3.3.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI response, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found one instance in which the applicant omitted components that should have been subject to an AMR. The applicant has satisfactorily resolved this issue as discussed in the preceding staff evaluation. On the basis of its review, the staff concludes that the applicant has appropriately identified the CCW system 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).

2.3A.3.4 IP2 Compressed Air Systems

2.3A.3.4.1 Summary of Technical Information in the Application

LRA Section 2.3.3.4 describes the compressed air systems, including the instrument air and station air systems. The instrument air system continuously supplies dry, oil-free air from duplicate compressors with duplicate dryers and filters for pneumatic instruments and controls. Indian Point Nuclear Generating Unit 1 (IP1) and IP2 station air systems provide alternate supplies. A connection in the station air system allows a backup supply from portable compressed air equipment. The instrument air system, although designed to meet air capacity requirements, utilizes the higher-capacity IP1 station air compressors as a primary source of supply. Because of the high-capacity output of the IP1 air compressors, they can supply all IP1 and IP2 station and instrument air requirements. The IP2 station air compressor and both IP2 instrument air compressors serve as backups. The system includes the compressors, dryers, filters, receivers, distribution piping and valves, instruments, and controls. Items essential for safe operation and cooldown have air reserves or gas bottles that enable the equipment to function safely until its air supply resumes. The instrument air system includes piping, air bottles, valves, and controls supporting this air reserve function, but excludes the air or gas bottle parts of other systems. The system also may supply air to the post-accident venting system to pressurize containment in support of hydrogen control, but this function is not safety related.

The station air system distributes compressed air to hose connections throughout the plant, primarily for maintenance activities. The station air system also serves as an alternate air supply to the instrument air system. Either an IP2 air compressor or the IP1 compressors and equipment provide station air. The station air system consists of IP1 and IP2 station air equipment, including air compressors, air receivers, filters, dryers, distribution piping, and valves.

The compressed air system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the compressed air system performs functions that support fire protection.

Instrument air system components that support safe shutdown in a fire in the auxiliary feed pump room are reviewed in LRA Section 2.3.4.5. Components containing nitrogen are reviewed with the nitrogen systems (LRA Section 2.3.3.5).

LRA Tables 2.3.3-4-IP2, 2.3.3-19-18-IP2, and 2.3.3-19-33-IP2 identify compressed air system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.3.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.4, UFSAR Sections 9.6.4 and 9.6.4.2, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3A.3.4.3 Conclusion

The staff reviewed the LRA, UFSAR, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the compressed air system 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).

2.3A.3.5 IP2 Nitrogen Systems

2.3A.3.5.1 Summary of Technical Information in the Application

LRA Section 2.3.3.5 describes the gas system, which stores and distributes gases, primarily hydrogen, carbon dioxide (CO_2), and nitrogen, for various uses around the plant. The gas system includes the hydrogen, CO_2, and nitrogen gas subsystems. The system supplies hydrogen to the chemical and VCT for oxygen scavenging of RCS water to support water chemistry control and to the main generator for cooling gas. CO_2 gas purges the main generator of hydrogen to support outage work on the generator. The nitrogen gas subsystem includes the various nitrogen supplies of motive gas to components as a backup to the instrument air supply and for process functions (including cover gas, purge gas, and gas required for operation of level instrumentation). Nitrogen enters containment through several penetrations. For the safe shutdown required by Appendix R to 10 CFR Part 50, nitrogen is necessary for pneumatically actuated components. The nitrogen gas subsystem supplies the atmospheric dump valves, backup nitrogen to AFW system valve actuators, a portable nitrogen bottle that can be carried into containment to operate the auxiliary spray valve, motive gas for the charging pumps suction valve, and pneumatically powered instrumentation. An SBO event requires nitrogen to be supplied to the atmospheric dump valves, the AFW system valve actuators, and pneumatically powered instrumentation.

The gas system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the gas system performs functions that support fire protection and SBO.

Gas system component parts of containment penetrations are reviewed with the containment penetrations (LRA Section 2.3.2.5). A small number of components are reviewed with the compressed air systems (LRA Section 2.3.3.4), the city water system (LRA Section 2.3.3.17), the plant drains (LRA Section 2.3.3.18), and the AFW systems (LRA Section 2.3.4.3).

LRA Tables 2.3.3-5-IP2 and 2.3.3-19-14-IP2 identify gas system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.3.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.5, UFSAR Sections 4.3.4.2, 7.2.1.5, 9.2, 10.2.2, and 10.2.6.3, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.3.5, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The discussion of the staff's RAIs in SER Section 2.3A.3 details the disposition of RAI 2.3A.3.5-1, dated February 13, 2008.

2.3A.3.5.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI response, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has appropriately identified the nitrogen system 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).

2.3A.3.6 IP2 Chemical and Volume Control System

2.3A.3.6.1 Summary of Technical Information in the Application

LRA Section 2.3.3.6 describes the CVCS, which controls RCS inventory (amounts of makeup and letdown) and chemistry (RCS boron concentration and other chemical additions). The system cleans up reactor coolant by degasification and purification, injects seal water to the RCPs, depressurizes the RCS via a pressurizer auxiliary spray flowpath, and injects control poison in the form of a boric acid solution from the boric acid storage tanks.

During normal plant operation, reactor coolant letdown flows through the shell side of the regenerative heat exchanger, which reduces its temperature by transferring heat to the charging fluid. The coolant then flows through a letdown orifice, which regulates flow and reduces coolant pressure. The cooled, low-pressure water leaves the reactor containment and enters the primary auxiliary building (PAB). After passing through the non-regenerative heat exchanger and one of the mixed-bed demineralizers, the fluid flows through the reactor coolant filter and enters the VCT.

The coolant flows from the VCT to three positive-displacement, variable-speed charging pumps, which raise the pressure to a level above that in the RCS. The high-pressure water flows from the PAB to the reactor containment along two parallel paths—one returning directly to the RCS through the tube side of the regenerative heat exchanger to the RCS cold leg, and the other injecting water into the RCP seals through seal injection filters. The RCP seal water returns to the CVCS through a seal water filter and heat exchanger back to the VCT.

The RWST and the boric acid storage tank can supply borated water to the charging system. The RWST is available to the charging pumps for injection of borated water. The boric acid system has boric acid transfer pumps, a boric acid filter, and storage tanks to maintain a large inventory of concentrated boric acid solution.

The CVCS contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the CVCS performs functions that support fire protection, ATWS, and SBO.

CVCS components that maintain the RCS pressure boundary are reviewed with the RCS pressure boundary (LRA Section 2.3.1.3). Some system components are reviewed with the primary water makeup systems (LRA Section 2.3.3.7).

LRA Tables 2.3.3-6-IP2 and 2.3.3-19-5-IP2 identify CVCS component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.3.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.6, UFSAR Section 9.2.2, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3A.3.6.3 Conclusion

The staff reviewed the LRA, UFSAR, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the CVCS 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).

2.3A.3.7 IP2 Primary Water Makeup System

2.3A.3.7.1 Summary of Technical Information in the Application

LRA Section 2.3.3.7 describes the primary water makeup system, which supplies makeup water to primary plant systems as required to support normal plant operation (e.g., tanks, piping, valves, pumps) The system includes containment penetration. The primary water makeup system can supply backup cooling water to safety-related components in a passive failure of the CCW system.

The primary water makeup system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function.

LRA Tables 2.3.3-7-IP2 and 2.3.3-19-29-IP2 identify primary water makeup system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.3.7.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.7, the UFSAR, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3A.3.7.3 Conclusion

The staff reviewed the LRA, UFSAR, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the primary water makeup system 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).

2.3A.3.8 IP2 Heating, Ventilation and Air Conditioning Systems

2.3A.3.8.1 Summary of Technical Information in the Application

LRA Section 2.3.3.8 describes the heating, ventilation, and air conditioning (HVAC) systems that maintain the area environment for personnel and equipment.

The HVAC systems include various ventilation subsystems serving various areas of the plant. With the exception of the containment cooling and filtration system and a few components in the operation of other mechanical systems, the HVAC system encompasses all IP2 ventilation systems and components and some from IP1. The main HVAC systems supporting plant operation include the following systems:

- containment purge supply and exhaust
- containment pressure relief
- containment iodine removal
- control rod drive mechanism (CRDM) cooling
- PAB ventilation
- fuel storage building ventilation
- cable spreading room/electrical tunnel ventilation
- 480 volt (V) switchgear room ventilation
- battery room exhaust
- EDG building ventilation
- auxiliary feed pump room ventilation
- diesel fire pump house ventilation
- electric fire pump room ventilation
- plant vent
- shield wall area enclosure heating and ventilation system
- SBO/Appendix R diesel generator ventilation
- portable HVAC credited in Appendix R
- security diesel room ventilation
- turbine hall ventilation
- technical support center ventilation
- administration building ventilation

LRA Section 2.3.3.9 addresses containment cooling and filtration, and LRA Section 2.3.3.10 addresses control room HVAC.

The containment purge supply and exhaust system supplies fresh air to purge the containment for personnel access. The system consists of a makeup air unit to supply fresh air, a filtration unit to filter the air released from containment, supply and exhaust ductwork, containment penetration piping, and valves. The system need not be in operation during DBAs or any regulated events. The system has two penetrations with safety-related piping and valves that support the containment isolation function. The pressure boundary function of system portions are also necessary to prevent air from being drawn into the shared fan housing for the containment purge and PAB exhaust fans.

The containment pressure relief system accommodates normal pressure changes in the containment during reactor power operation. This system consists of a filtration unit, fan, pressure relief ductwork, containment penetration piping, and valves. The system need not be in operation during DBAs or any regulated events. The system has a penetration with safety-related piping and valves that support the containment isolation function.

The containment iodine removal system consists of two auxiliary particulate and charcoal filter units in the containment, primarily used for pre-access cleanup. During power operation, the containment air particulate and gas monitor indications help determine whether to use either or both of these units. These units, wholly contained within containment, are not safety related or required during DBAs or regulated events.

The CRDM cooling system maintains the control rod drive operating coil stacks below their maximum allowable temperature during normal operation. Four fans take suction from the control rod drive shroud and discharge into the containment atmosphere. This equipment is not required to function during accident conditions or in response to regulated events.

The PAB ventilation system ventilates the waste hold-up tank pit and enclosed spaces in the PAB. The waste hold-up tanks in the waste hold-up tank pit are the central collection points for liquid radioactive waste. The PAB houses equipment and components required for normal plant operation, as well as accident mitigation. The PAB heating and ventilation system maintains an operating environment for personnel and equipment during normal operating and post-accident conditions with supply and exhaust fans with ductwork and dampers. None of the applicant’s dose consequence analyses credit filtration. The PAB ventilation system is in use during normal operating conditions (plant start-up, power operation, and normal shutdown). This system must also operate during DBAs and for safe shutdown following a fire.

The fuel storage building heating and ventilation system heats and ventilates that building, minimizes leakage of unfiltered air from the building during fuel-handling operations, and filters building exhaust. The system has two fresh air tempering units with supply fans and heaters, exhaust roughing, high-efficiency particulate air (HEPA) and carbon filters, an exhaust fan, motor-operated dampers, and ducts. The applicant originally credited the system in the fuel-handling accident; however, the analysis described in UFSAR Section 14.2.1.1, which uses the alternate source term, no longer assumes operation of the ventilation system or any holdup of the radionuclides released from the spent fuel pit. Consequently, the system has no safety functions.

The cable spreading room/electrical tunnel exhaust system ventilates the 33-foot elevation of the control building. The system consists of two exhaust fans mounted above the tunnel in a plenum. Intake louvers on the north and south walls draw air into the cable- spreading room. The system maintains an operating environment for personnel and equipment during normal operating and post-accident conditions and is required for cooling during DBAs, as well as regulated events.

The 480-V electrical switchgear room ventilation system ventilates that room at the 15-foot elevation of the control building, using three fans mounted in the north wall. The fans take suction from the switchgear room and discharge outside. A fixed louver with fire damper allows air to flow into the room. The system maintains an operating environment for personnel and equipment during normal operating and post-accident conditions and is required for cooling during DBAs, as well as regulated events.

Battery rooms in the control and superheater buildings have exhaust fans to prevent long-term buildup of hydrogen during normal operation when the batteries charge. These exhaust fans need not function during DBAs or regulated events.

The EDG building ventilation system has exhaust fans, exhaust dampers, and intake louvers. These HVAC components are required to support diesel operation during DBAs, as well as regulated events such as the Appendix R safe shutdown.

The heating and ventilation system of the auxiliary boiler feed pump building, which is in use during normal operating conditions, consists of several exhaust fans for cooling. A roll-up door can be opened for cooling during emergency operation of the AFW system. Following a fire, portable blowers can ventilate this area; therefore, the applicant stated that operation of the auxiliary boiler feed pump building heating and ventilation system is not required during DBAs or regulated events.

The diesel fire pump house ventilation system cools the structure housing the diesel fire pump. This structure is cooled by louvers, and the diesel itself is cooled by fire water. These HVAC components are required to support fire system operation credited in Appendix R evaluations.

The electric fire pumps are located in two rooms in the IP1 turbine building cooled by exhaust fans and dampers that cool the electric fire pumps. These HVAC components are required to support fire system operation credited in Appendix R evaluations.

The plant vent system, which provides a flowpath for the exhaust to the atmosphere, includes the plant vent duct and some vent flow monitoring instrumentation. The offsite dose analyses does not credit the plant vent as the release point but, because of its proximity to the control room air intake, the control room dose calculations do consider the plant vent to be the release point.

The IP2 shield wall area enclosure heating and ventilation system heats and ventilates the shield wall area enclosure. Components and piping primarily associated with the MS and FW systems are located in the main enclosure. The shield wall area enclosure heating and ventilation system is in use during normal operating conditions, such as plant start-up, power operation, and normal shutdown. The operation of this equipment is not required during DBAs or regulated events.

IP2 installed a new SBO and Appendix R diesel generator credited with supplying backup power to the plant to assist in safe shutdown following a fire or an SBO. Its associated ventilation equipment is required for its function. The IP2 SBO/Appendix R diesel generator ventilation system utilizes louvers, an exhaust fan, and outlet ductwork. The fan will operate when the diesel operates.

The Appendix R safe-shutdown report indicates that, for a fire in certain plant areas, portable blowers and flexible ductwork can ventilate the safe-shutdown equipment, and are therefore required by Appendix R. Power can be supplied by portable generators.

The IP2 security diesel generator is credited for emergency lighting for some areas to support safe shutdown following a fire. The ventilation equipment that cools this diesel consists of dampers, ductwork, and an engine-driven blower that ventilates the room when the engine operates. This ventilation is required for the operation of the security diesel credited with providing power for lighting, as required by Appendix R.

Using fixed and adjustable louvers and awning sashes, the turbine building ventilation system draws in air exhausted by power roof ventilators and wall exhaust fans. This cooling is not required during DBAs and regulated events.

The technical support center ventilation system maintains environmental conditions in the center. The system, which includes fans, dampers, filters, and cooling equipment, performs no safety-related functions during accident conditions and is not required for any regulated events.

The administration building ventilation system, which heats, ventilates, and provides air conditioning to administration building personnel and equipment, is not required during DBAs or regulated events.

The HVAC system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure could prevent the satisfactory accomplishment of a safety-related function. In addition, the HVAC system performs functions that support fire protection and SBO.

Some HVAC components are reviewed with the compressed air systems (LRA Section 2.3.3.4) or with the containment cooling and filtration systems (LRA Section 2.3.3.9).

LRA Tables 2.3.3-8-IP2 and 2.3.3-19-17-IP2 identify HVAC system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.3.8.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.8; UFSAR Sections 5.3.2, 9.8, and 9.10; and a license renewal drawing using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3A.3.8.3 Conclusion

The staff reviewed the LRA, UFSAR, and a drawing to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the HVAC system 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).

2.3A.3.9 IP2 Containment Cooling and Filtration System

2.3A.3.9.1 Summary of Technical Information in the Application

LRA Section 2.3.3.9 describes the containment cooling and filtration system. The IP2 containment cooling and filtration system cools the containment. Air-handling units, discharging into a common header ductwork distribution system, achieve air recirculation cooling during normal operation and ensure adequate flow of cooled air throughout the containment. Each air-handling unit consists of equipment arranged so that, during normal and accident operation, air flows through the unit in the following sequence: cooling coils, moisture separators (demisters), centrifugal fan with direct-drive motor, and distribution header. The system rejects heat to SW system cooling coils in normal operation, emergency operation, and safe-shutdown cooling following a fire.

The containment cooling and filtration system contains safety-related components relied on to remain functional during and following DBEs. In addition, the containment cooling and filtration system performs functions that support fire protection and SBO.

LRA Table 2.3.3-9-IP2 identifies containment cooling and filtration system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.3.9.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.9, UFSAR Sections 5.3.2.2 and 6.4.2, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3A.3.9.3 Conclusion

The staff reviewed the LRA, UFSAR, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the containment cooling and filtration system 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).

2.3A.3.10 IP2 Control Room Heating, Ventilation and Cooling System

2.3A.3.10.1 Summary of Technical Information in the Application

LRA Section 2.3.3.10 describes the control room ventilation system, which maintains the central control room in a safe, habitable environment during normal operation and under accident conditions. The system has an air-conditioning unit with fan, steam heating coil, roughing filter to recirculate air inside the control room, a backup fan in parallel with the air-conditioning unit, and a filter unit consisting of HEPA filters, charcoal filters, post-filters, and booster fans to permit filtration of incoming air for a slight positive pressure in the control room during accident conditions. System ducts, dampers, and controls allow three system operating modes: Mode 1 (normal operation) with outside air makeup, Mode 2 (safety injection or high radiation) with outside filtered air, and Mode 3 (toxic gas or smoke) with all outside air isolated. Control room dose analyses credit the operation of this system, including the filtration of incoming air. IP1 and IP2 share a central control room. The IP1 control room ventilation equipment is modified for recirculation mode only.

The central control room system contains safety-related components relied upon to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the central control room system performs functions to maintain the central control room in a safe, habitable environment during an Appendix R event and SBO.

LRA Tables 2.3.3-10-IP2 and 2.3.3-19-17-IP2 identify central control room HVAC system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.3.10.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.10, UFSAR Section 9.9, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3A.3.10.3 Conclusion

The staff reviewed the LRA, UFSAR, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the central control room HVAC system 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).

2.3A.3.11 IP2 Fire Protection – Water

2.3A.3.11.1 Summary of Technical Information in the Application

LRA Section 2.3.3.11 describes the fire protection system, which provides fire protection for the station through the use of water, dry chemicals, foam, detection and alarm systems, and rated fire barriers, doors, and dampers. Passive mechanical components in the fire protection system include many firefighting subsystem components and features, such as piping, fire dampers, valves, hydrants, portable fire extinguishers, and two fire water storage tanks. Also included under this system code (i.e., the applicant's code for designating systems and boundaries) are the IP1 fire pumps and some associated IP1 fire protection components, such as hydrants, valves, fire extinguishers, and strainers. Plant drain components in the fire protection system are passive fire protection features required to ensure adequate protection of safety-related equipment from water damage in areas containing fixed suppression systems.

The fire protection—water system draws water from two storage tanks, a 1.5-million-gallon tank supplied by the city water distribution system for fire protection purposes and a 300,000-gallon fire water storage tank of city water as a redundant supply for the water-based fire protection systems. The pumping facilities consist of two electric fire pumps taking suction from the site's city water main. Two small electric pumps also maintain pressure for the fire water system. A diesel fire pump for redundant pumping capabilities normally takes suction from the 300,000-gallon fire water storage tank. The pumping facilities meet flow and pressure requirements for water-based fire protection systems. The fire protection water distribution system consists of outdoor underground piping, indoor distribution piping, isolation valves, strainers, hose stations, and outdoor hydrants.

The water-based fire suppression systems include the wet pipe sprinkler systems, preaction sprinkler systems, deluge water spray systems, foam water spray systems, and hydrants and hose stations.

According to the LRA, the fire protection—water system has no intended function under 10 CFR 54.4(a)(1). The scoping and screening methodology identified the following fire water system intended functions, in accordance with 10 CFR 54.4(a)(2):

- Maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function.
- Provide a backup source of makeup water to the spent fuel pit.

The scoping and screening methodology also identified the following the fire water system intended functions, in accordance with 10 CFR 54.4(a)(3):

- Provide fixed automatic and manual fire suppression (including hydrants, hose stations and portable extinguishers) to extinguish fires in vital areas of the plant (10 CFR 50.48).
- Ensure adequate protection of safety-related equipment from water damage in areas susceptible to flooding (10 CFR 50.48).
- Ensure that drain systems in areas containing combustible materials prevent the spreading of fires into other areas of the plant (10 CFR 50.48).

LRA Section 2.3.3.12 evaluates the fire protection—CO_2, Halon 1301, and RCP oil collection systems.

The drain portion of the system is evaluated with plant drains (LRA Section 2.3.3.18). The fuel oil subsystem components are evaluated with fuel oil systems (LRA Section 2.3.3.13). A small number of components are evaluated with city water systems (LRA Section 2.3.3.17).

The applicant evaluated those nonsafety-related components that were not evaluated with other systems and whose failure could prevent satisfactory accomplishment of safety functions with miscellaneous systems within the 10 CFR 54.4(a)(2) scope of license renewal (LRA Section 2.3.3.19).

LRA Tables 2.3.3-11-IP2 and 2.3.3-19-11-IP2 identify fire protection—water system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.3.11.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.11, UFSAR Section 9.6.2, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR, Section 2.3. During its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant had not omitted from the scope of license renewal any components with intended functions, as required by 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 it had not omitted any passive and long-lived components subject to an AMR in accordance with 10 CFR 54.21(a)(1).

The staff also reviewed the following IP2 fire protection CLB documents listed in the IP2 Operating License Condition 2.K: NRC fire protection SERs for IP2, dated November 30, 1977; February 3, 1978; January 31, 1979; October 31, 1980; August 22, 1983; March 30, 1984; October 16, 1984; September 16, 1985; November 13, 1985; March 4, 1987; January 12, 1989; and March 26, 1996.

The staff also reviewed IP2 commitments made in response to the requirements of 10 CFR 50.48 (i.e., an approved fire protection program), using its commitment responses to Branch Technical Position (BTP) Auxiliary and Power Conversion Systems Branch (APCSB) 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants," dated May 1, 1976, and Appendix A to BTP APCSB 9.5-1, dated August 23, 1976.

During its review of LRA Section 2.3.3.11, the staff identified areas in which additional information was necessary to complete its review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

In RAI 2.3A.3.11-1, dated October 24, 2007, the staff questioned why the license renewal drawings identified certain fire protection system components as not subject to an AMR. Specifically, License renewal drawing LRA-227551-0 shows the following fire protection system components as not subject to an AMR (i.e., they are not highlighted in green):

- maintenance and outage building
- PAB and boric acid building charcoal filter deluge system

License renewal drawing LRA-227552-0 shows the following fire protection system components as not subject to an AMR (i.e., they are not highlighted in green):

- No. 11 fire pump room
- fuel oil tank/water meter house
- ignition oil tank and pump room deluge system
- main and auxiliary transformer deluge system

License renewal drawing LRA-227553-0 shows the following fire protection system components as not subject to an AMR (i.e., they are not highlighted in green):

- staircase Nos. 2, 3, 4, 5 and 6
- turbine oil piping system

License renewal drawing LRA-227554-0 shows the following fire protection system component as not subject to an AMR (i.e., it is not highlighted in green):

- staircase Nos. 1, 8, and 9

License renewal drawing LRA-9321-4006-0 shows the following fire protection system components as not subject to an AMR (i.e., they are not highlighted in green):

- fire hydrants
- fire hose connections
- fire hose stations

In the RAI, the staff requested that the applicant verify whether the above components 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). The staff requested that the applicant justify excluding these components from the scope of license renewal and an AMR.

In its response, dated November 16, 2007, the applicant provided scoping and screening results for the fire protection system components in question in license renewal drawing LRA-227551-0. For the maintenance and outage building, the applicant stated the following:

> The maintenance and outage building adjacent to the fuel storage building of IP2 houses offices and facilities for maintenance personnel. The maintenance and outage building fire protection components are not required for 10 CFR 50.48 as the building does not house and is not in proximity to safety-related equipment, nor does it contain equipment required for safe-shutdown. The maintenance and outage building fire protection components are not described in the January 31, 1979, fire protection SER.

Based on its review, the staff finds the applicant's response acceptable because the maintenance and outage building does not have a license renewal intended function. The maintenance and outage building does not require fire protection in accordance with the provisions of 10 CFR 50.48; therefore, the associated fire protection components are not within the scope of license renewal.

For the PAB charcoal filter deluge system, the applicant stated the following:

> Drawing LRA-227551-0 detail E shows piping and solenoid valves downstream of FP-587 for the PAB charcoal filter deluge system. These portions of the system were inadvertently not highlighted on the drawing as subject to an AMR for license renewal. The PAB charcoal filter deluge system is in-scope and subject to an AMR. Applicable component types are included in LRA Table 2.3.3-11-IP2 with the AMR results in LRA Table 3.3.2-11-IP2.

Based on its review, the staff finds the applicant’s response acceptable because it indicated that the PAB charcoal filter deluge system is within the scope of license renewal and subject to an AMR.

For the boric acid building charcoal filter deluge system, the applicant stated the following:

> The boric acid building charcoal filter deluge system is in-scope and subject to an AMR as shown on drawing LRA-227551-0 in detail E and detail F. Applicable component types are included in LRA Table 2.3.3-11-IP2 with the AMR results in LRA Table 3.3.2-11-IP2.

Based on its review, the staff finds the applicant’s response acceptable because it indicated that the boric acid building charcoal filter deluge system is within the scope of license renewal and subject to an AMR.

In its response, dated November 16, 2007, the applicant provided scoping and screening results for the fire protection system components in license renewal drawing LRA-227552-0. For the No.11 Fire Pump Room, the applicant stated the following:

> The portion of the fire protection system labeled on drawing LRA-227552-0 as No.11 fire pump room includes systems for gas turbine No. 1 Transformer, expanded portion of the maintenance area, the L&P Transformer, the bulk H2 storage (screenwell house) for Unit 1, and the maintenance material processing area. This portion of the system is not required to meet 10 CFR 50.48 requirements for the following reasons. Deluge valve FP-294 feeds the line that is blind-flanged to the gas turbine No. 1 Transformer which is retired in place. A fire in this area cannot adversely impact safety-related equipment. Deluge valve FP-1008 feeds the expanded portion of the maintenance area which houses no safety-related equipment. A fire in this area cannot affect areas containing safety-related equipment. Deluge valve FP-242 supplies spray system No. 1 which protects the L&P Transformer which is retired in place. A fire in this area cannot adversely impact safety-related equipment. Deluge valve FP-261 supplies the line for spray system No. 4 to the bulk H2 storage (screenwell house) for Unit 1, and deluge valve FP-890 supplies the line for the maintenance material processing area.
>
> These areas do not contain safety-related equipment, and a fire in the areas cannot affect areas containing safety-related equipment. None of these fire protection systems are described in the January 31, 1979, fire protection SER.

Based on its review, the staff finds the applicant's response acceptable because the portion of the fire protection system identified does not have a license renewal intended function and is not subject to an AMR, in accordance with 10 CFR 54.4(a) or 10 CFR 54.21(a)(1), respectively.

For the fuel oil tank/water meter house, the applicant stated the following:

> As shown on drawing LRA-227552-0 detail J (fuel oil tank/water meter house), hydrants No. 18 and No. 19 provide fire protection coverage for fuel oil storage tanks. The fuel oil storage tanks are associated with house service boiler and ignition oil tanks. These fuel oil tanks have no intended function for license renewal. They are not required to meet 10 CFR 50.48 requirements since a fire in this portion of the yard cannot affect safety-related or safe-shutdown equipment. In addition, this equipment is not described in the January 31, 1979, fire protection SER. Fire protection components associated with the water meter house (piping and valves) are in-scope and subject to an AMR and are shown on drawing LRA-192505. These components (piping and valves) are part of the city water system discussed in Section 2.3.3.17 of the LRA.

Based on its review, the staff finds the applicant's response acceptable. The fuel oil tank does not have a license renewal intended function and is, therefore, excluded from the scope of license renewal and is not subject to an AMR. The staff notes that the water meter house fire protection components are within the scope of license renewal, subject to an AMR, and shown on drawing LRA-192505.

For the ignition oil tank and pump room deluge system, the applicant stated the following:

> The ignition oil tank and pump rooms are in the Indian Point Nuclear Generating Unit 1 (IP1) super-heater building (not adjacent to IP2 areas containing safety-related equipment). These rooms do not contain safety-related equipment or systems required for safe-shutdown. Three-hour rated walls, penetrations, and doors will prevent a fire in the ignition oil tank and pump room from spreading to safety-related areas associated with IP2. The ignition oil tank and pump room deluge system is not required to meet 10 CFR 50.48 and is not described in the January 31, 1979, fire protection SER.

Based on its review, the staff finds the applicant's response acceptable because the ignition oil tank and pump room deluge system is not required by 10 CFR 50.48 and is, therefore, outside the scope of license renewal.

For the main and auxiliary transformer deluge system, the applicant stated the following:

> The main and auxiliary transformer deluge systems and their associated components for the oil filled transformers adjacent to the control building were initially determined to have no license renewal intended function. They were considered required only to protect the transformers to satisfy requirements of the plant insurance carrier. However, the spray systems provide for defense in depth in addition to installed 3-hour rated fire barriers and are now considered in-scope and subject to an AMR for license renewal. Applicable component types that are subject to an AMR are included in LRA Table 2.3.3-11-IP2 with the AMR results in LRA Table 3.3.2-11-IP2.

Based on its review, the staff finds the applicant's response acceptable because it clarifies that (1) the main and auxiliary transformer deluge systems and their associated components have no license renewal intended function and (2) the spray systems provide for defense in depth, in addition to the installed 3-hour-rated fire barriers, and are considered in scope and subject to an AMR for license renewal. The staff's concern is resolved.

In its response, dated November 16, 2007, the applicant provided scoping and screening results for the fire protection system components in license renewal drawing LRA-27553-0. For staircase Nos. 2, 3, 4, 5 and 6, the applicant stated the following:

> Staircase No. 2 is located in the IP1 service building adjacent to the IP1 turbine building. The service building for IP1 houses administrative offices. Staircases No. 5 and No. 6 are located in the IP1 super-heater building at the south exterior wall. None of these areas are in proximity to areas containing safety-related equipment. Fires in the areas of Staircases No. 2, 5, and 6 are prevented from spreading to nearby safety-related areas (IP2 control building) by three-hour rated walls, penetrations, and doors. Fire protection equipment in Staircases No. 2, 5, and 6 are not required for 10 CFR 50.48 and are not described in the January 31, 1979, fire protection SER.
>
> Fire protection equipment for Staircase No. 4 at Elevation 53', located in the control building, is in-scope and subject to an AMR as shown on drawing LRA-227553-0 at detail WW.
>
> The supply to the radwaste/HP offices downstream of valve FP-363 and components downstream of normally closed valve FP-155 are not required for 10 CFR 50.48 because these areas do not contain safety-related equipment nor can a fire in the radwaste/HP offices impact areas containing safety-related equipment.
>
> Fire protection for Staircase No. 3 at Elevation 15', 33', and 53' in the control building is in-scope and subject to an AMR as shown on drawing LRA-227553-0 at detail W.
>
> The supply to the technical support building (TSC) downstream of valve FP-865 is not required for 10 CFR 50.48 because this area does not contain safety-related equipment nor can a fire in the technical support building impact areas containing safety-related equipment.

Based on its review, the staff finds the applicant's response acceptable because it clarifies that (1) fire protection systems in staircase Nos. 2, 5, and 6 are not required to comply with the requirements of 10 CFR 50.48, (2) fire protection system equipment for staircase No. 4 is within the scope of license renewal and subject to an AMR, as shown on license renewal drawing LRA-227553-0, and (3) the fire protection system for staircase No. 3 also is in scope and subject to an AMR, as shown on license renewal drawing LRA-227553.

For the turbine oil piping system, the applicant stated the following:

> Turbine oil piping sprinkler system components downstream of valve FP-65

> provide coverage for the file room, one stop shop building, and the work control center building, none of which contains, or can impact areas containing, safety-related equipment. The turbine oil piping sprinkler system is therefore not required for compliance with 10 CFR 50.48. However, hose reel FP-66 and associated piping are in-scope and subject to an AMR for license renewal as shown on drawing LRA-227553-0 at detail X.

Based on its review, the staff finds the applicant's response acceptable because it clarifies the portion of the turbine oil piping sprinkler system components that are not required under 10 CFR 50.48. These components are not within the scope of license renewal because the areas that they cover do not contain safety-related equipment and a fire in these locations cannot impact areas containing safety-related equipment.

In its response, dated November 16, 2007, the applicant provided scoping and screening results for the fire protection system components in license renewal drawing LRA-227554-0. For staircase Nos. 1, 8, and 9, the applicant stated the following:

> Staircase No. 1 is located in the IP1 nuclear service building and Staircases No. 8 and 9 are located in the IP1 nuclear service chemical system building. The nuclear service building is adjacent to the IP1 containment building and houses no safety-related equipment. The nuclear service chemical system building is adjacent to the IP1 containment building and houses no safety-related equipment. These buildings are not in proximity to areas containing safety-related equipment. Fires in the areas of Staircases No. 1, 8, and 9 are prevented from spreading to safety-related areas (control building) by three-hour rated walls, penetrations, and doors. Fire protection equipment in Staircases Nos. 1, 8, and 9 is not required for 10 CFR 50.48. These staircases are associated with IP1 and the associated fire protection system components are no longer required for compliance with 10 CFR 50.48 since the IP1 operating license was revoked in June 1980 as stated in the October 31, 1980, supplement to the January 31, 1979, fire protection SER.

Based on its review, the staff finds the applicant's response acceptable because it clarifies that staircase Nos. 1, 8, and 9 are associated with IP1, and the associated fire protection system components are no longer required for compliance with 10 CFR 50.48.

In its response, dated November 16, 2007, the applicant provided scoping and screening results for the fire protection system components depicted on license renewal drawing LRA-9321-4006-0 that are in question. For fire hydrants, the applicant stated the following:

> Hydrants for the IP2 screenwell structure (Hydrants 21 and 22), main transformer yard (Hydrant 25), emergency diesel generators building (Hydrant 27), primary auxiliary building (Hydrants 26, 28, and 29), and auxiliary feed pump building (Hydrant 24) are required for 10 CFR 50.48. These hydrants are highlighted on LRA drawing LRA-9321-4006-0.
>
> Hydrants that are not highlighted are those for the IP1 screenwell house (Hydrants 11 and 12), IP1 fuel oil tank farm (Hydrants 17 and 18), east of IP1 fuel handling building (Hydrant 16), station security building (Hydrant 15), and

> southeast of the IP1 containment building (Hydrants 13 and 14). These hydrants are not required for 10 CFR 50.48. The IP1 screenwell house does contain equipment for safe-shutdown in the event of fire in another area. Fires are not assumed to occur in multiple fire zones, so a fire in the screenwell house is not a concern. The other areas listed do not present a significant fire hazard to areas containing equipment used for safe-shutdown.

Based on its review, the staff finds the applicant's response acceptable because it clarifies that hydrants 21, 22, 24, 25, 26, 27, 28, and 29 are required by 10 CFR 50.48. The applicant has highlighted these hydrants on license renewal drawing LRA-9321-4006-0. In addition, hydrants 11, 12, 13, 14, 15, 16, 17, and 18 are not highlighted because they are associated with IP1. The IP1 hydrants are no longer required for compliance with 10 CFR 50.48.

For fire hose connections, the applicant stated the following:

> Fire hose connections that are not highlighted on drawing LRA-9321-4006-0 coordinates (B2) are located at the IP1 screenwell house dock and are not required for 10 CFR 50.48. The hose connection at the IP1 screenwell house is isolated with a blank flange.

Based on its review, the staff finds the applicant's response acceptable because it clarifies that fire hose connections that are not highlighted on license renewal drawing LRA-9321-4006-0 are associated with the IP1 screenwell house dock and are no longer required for compliance with 10 CFR 50.48, since the IP1 operating license was revoked in June 1980.

For fire hose stations, the applicant stated the following:

> The fire hose stations that are not highlighted on drawing LRA-9321-4006-0 are in the IP1 fuel handling building and are not required for 10 CFR 50.48. This area does not contain equipment used for safe-shutdown and is an area that does not present a significant fire hazard to areas containing equipment used for safe-shutdown. Fire hose stations associated with IP1 and the associated fire protection system components are no longer required for compliance with 10 CFR 50.48 since the IP1 operating license was revoked in June 1980 as stated in the October 31, 1980, supplement to the January 31, 1979, fire protection SER.

Based on its review, the staff finds the applicant's response acceptable because it clarifies that fire hose stations that are not highlighted on license renewal drawing LRA-9321-4006-0 are in the IP1 fuel-handling building and are no longer required by 10 CFR 50.48, since the IP1 operating license was revoked in June 1980.

At the request of the staff, the applicant clarified its statements made in its November 16, 2007 response to RAI 2.3A.3.11-1 regarding IP1 fire protection components that were stated to be no longer required for compliance with 10 CFR 50.48. By letter dated August 6, 2009, the applicant clarified that IP1 fire protection components identified in its response dated November 16, 2007 that are specifically used only to support IP1 do not have an intended function for IP2 or IP3. Since they are not required to demonstrate compliance with 10 CFR 50.48 for IP2 or IP3, the applicant determined that they are not within the scope of license renewal. Entergy further stated that the IP1 components are credited in the IP1 fire protection program which meets the requirements in 10 CFR 50.48(f). The staff notes that 10 CFR 50.48(f) applies to reactors that have permanently ceased operations, and does not apply to IP2 or IP3.

The staff finds the applicant's response acceptable because it clarified that the IP1 components that support IP1 fire protection program are not needed to support the operation of IP2 or IP3, and therefore, they are not within the scope of license renewal.

Based on its review, the staff finds the applicant's response to RAI 2.3A.3.11-1, as clarified, acceptable. The staff's concern described in RAI 2.3A.3.11-1 is resolved.

In RAI 2.3A.3.11-2, dated October 24, 2007, the staff stated that LRA Tables 2.3.3-11-IP2 and 2.3.3-11-IP3 exclude several types of fire protection components that are discussed in the fire protection SERs or UFSAR or both and which also appear on the license renewal drawings as subject to an AMR (i.e., they are highlighted in green). These components include the following:

- hose connections
- hose racks
- yard hose houses
- interior fire hose stations
- pipe fittings
- pipe supports
- couplings
- threaded connections
- restricting orifices
- interface flanges
- chamber housings
- heat-actuated devices
- tank heaters
- thermowells
- water motor alarms
- expansion joint
- filter housing
- gear box housing
- heat exchanger (bonnet)
- heat exchanger (shell)
- heat exchanger (tube)
- heater housing
- diesel-driven fire pump engine's muffler
- orifice
- sight glass
- strainer housing
- turbocharger housing
- flexible hose
- latch door pull box
- pneumatic actuators
- actuator housing
- dikes for oil spill confinement
- buried underground fuel oil tanks for EDGs
- expansion tank
- fire water main loop valves

- post-indicator valves
- jacket cooling water keep-warm pump and heater
- lubricating oil collection system components for each RCP
- lubricating oil cooler
- auxiliary lubricating oil makeup tank
- rocker lubricating oil pump
- floor drains and curbs for fire-fighting water
- backflow prevention devices
- flame retardant coating for cables
- fire retardant coating for structural steel supporting walls and ceilings

The staff requested that the applicant verify whether LRA Tables 2.3.3-11-IP2 and 2.3.3-11-IP3 should include the components listed above. If they are excluded from the scope of license renewal and not subject to an AMR, the staff requested that the applicant justify their exclusion.

In its response, dated November 16, 2007, the applicant provided the results of scoping and screening for the listed fire protection system component types as follows:

> Hose connections—As stated in LRA Section 2.0 Page 2.0-1, the component type “piping” includes pipe, pipe fittings (such as elbows and reducers), flow elements, orifices, and thermowells. Hose connections are pipe fittings subject to an AMR as indicated in LRA Tables 2.3.3-11-IP2 and 2.3.3-11-IP3 under the component type “piping,” with the AMR results provided in LRA Tables 3.3.2-11-IP2 and 3.3.2-11-IP3.
>
> Hose racks—Hose racks subject to an AMR are included in the structural AMR as component type “fire hose reels.” This item is included in LRA Table 2.4-4, with the AMR results provided in LRA Table 3.5.2-4.
>
> Yard hose houses—Yard hose houses (small buildings over hydrants which contain fire hose and fire fighting equipment) are not subject to an AMR. Failure of a yard hose house would not prevent fire suppression capability of the associated hydrant.
>
> Interior fire hose stations—Interior fire hose stations are subject to an AMR. They are included in LRA Table 2.4-4 under component type “fire hose reels,” with the AMR results provided in LRA Table 3.5.2-4.
>
> Pipe fittings—As stated in LRA Section 2.0 on Page 2.0-1, the component type piping” may include pipe, pipe fittings (such as elbows and reducers), flow elements, orifices, and thermowells. Pipe fittings are subject to an AMR and included in LRA Tables 2.3.3-11-IP2 and 2.3.3-11-IP3 under the component type “piping” with the AMR results in LRA Tables 3.3.2-11-IP2 and 3.3.2-11-IP3.
>
> Pipe supports—Pipe supports are subject to an AMR and are included in the structural AMR as component type “component and piping supports.” This item is included in LRA Table 2.4-4, with the AMR results provided in LRA Table 3.5.2-4.
>
> Couplings—As stated in LRA Section 2.0 Page 2.0-1, the component type “piping” may include pipe, pipe fittings (such as elbows and reducers), flow

elements, orifices, and thermowells. Couplings are subject to an AMR and included in LRA Tables 2.3.3-11-IP2 and 2.3.3-11-IP3 under the component type “piping,” with the AMR results provided in LRA Tables 3.3.2-11-IP2 and 3.3.2-11-IP3.

Threaded connections—As stated in LRA Section 2.0 Page 2.0-1, the component type “piping” may include pipe, pipe fittings (such as elbows and reducers), flow elements, orifices, and thermowells. Threaded connections are considered pipe fittings and are included in LRA Tables 2.3.3-11-IP2 and 2.3.3-11-IP3 under the component type “piping,” with the AMR results provided in LRA Tables 3.3.2-11-IP2 and 3.3.2-11-IP3.

Restricting orifices—As stated in LRA Section 2.0 Page 2.0-1, the component type “piping” may include pipe, pipe fittings (such as elbows and reducers), flow elements, orifices, and thermowells. Restricting orifices in the fire protection water systems are included in the “piping” line item in LRA Tables 2.3.3-11-IP2 and 2.3.3-11-IP3, with the AMR results provided in LRA Tables 3.3.2-11-IP2 and 3.3.2-11-IP3.

Interface flanges—As stated in LRA Section 2.0 Page 2.0-1, the component type “piping” may include pipe, pipe fittings (such as elbows and reducers), flow elements, orifices, and thermowells. Interface flanges are subject to an AMR and included in LRA Tables 2.3.3-11-IP2 and 2.3.3-11-IP3 under the component type “piping,” with the AMR results provided in LRA Tables 3.3.2-11-IP2 and 3.3.2-11-IP3.

Chamber housings—Deluge valves for IP2 and IP3 include a retard chamber, piping, and valves whose purposes are to prevent false alarms due to system pressure surges and to provide a flow path to the water gong alarm during system actuation. Since failure of these components of the deluge valve would not prevent fire suppression capability for the sprinkler system, they are not subject to an AMR.

Heat-actuated devices—Heat actuated devices are active components not subject to an AMR.

Tank heaters—Tank heaters are active components not subject to an AMR.

Thermowells—Thermowells are included in Tables 2.3.3-11-IP2 and 2.3.3-11-IP3, with the AMR results provided in LRA Tables 3.3.2-11-IP2 and 3.3.2-11-IP3.

Water motor alarms—Water motor alarms are local bells mechanically driven by water flow. Water motor alarms are active components not subject to an AMR.

Expansion joint—Expansion joint is a component type in the fire pump diesel exhaust system and is included in Tables 2.3.3-11-IP2 and 2.3.3-11-IP3, with the AMR results provided in LRA Tables 3.3.2-11-IP2 and 3.3.2-11-IP3.

Filter housing—Filter housing is only associated with IP3 components shown on drawing LRA-9321-40903-0. Filter housing is a component type shown in Table 2.3.3-11-IP3, with the AMR results provided in LRA Table 3.3.2-11-IP3.

Gear box housing—Gear box housings are part of the vendor supplied fire pump diesel engine assembly which is an active component not subject to an AMR.

Heat exchanger (bonnet)—There is no heat exchanger (bonnet) associated with the fire protection systems.

Heat exchanger (shell)—There is no heat exchanger (shell) associated with the fire protection systems.

Heat exchanger (tube)—There is no heat exchanger associated with the fire water systems. The IP3 CO2 system includes a heat exchanger consisting of a coil (tube) in air, which is addressed in LRA Table 2.3.3.12-IP3 as component type heat exchanger (tube), with the AMR results provided in LRA Table 3.3.2-12-IP3.

Heater housing—Heater housings are included in Tables 2.3.3-11-IP2 and 2.3.3 11-IP3, with the AMR results provided in LRA Tables 3.3.2-11-IP2 and 3.3.2-11-IP3.

Diesel driven fire pump engine muffler—The diesel driven fire pump engine muffler is component type "silencer" included in Tables 2.3.3-11-IP2 and 2.3.3-11-IP3, with the AMR results provided in LRA Tables 3.3.2-11-IP2 and 3.3.2-11-IP3.

Orifice—As stated in LRA Section 2.0 Page 2.0-1, the component type "piping" may include pipe, pipe fittings (such as elbows and reducers), flow elements, orifices, and thermowells. Orifices in the fire protection water systems are included in LRA Tables 2.3.3-11-IP2 and 2.3.3-11-IP3 under the component type "piping," with the AMR results provided in LRA Tables 3.3.2-11-IP2 and 3.3.2-11-IP3.

Sight glass—Sight glasses are not a component type in the fire protection systems subject to an AMR.

Strainer housing—Strainer housings are included in Tables 2.3.3.11-IP2 and 2.3.3-11-IP3, with the AMR results provided in LRA Tables 3.3.2-11-IP2 and 3.3.2-11-IP3.

Turbocharger housing—Turbocharger housing is a part of the fire pump diesel engine assembly, which is an active component not subject to an AMR.

Flexible hose—Flexible hoses are replaced at specified intervals and are therefore not subject to an AMR per 10 CFR 54.21(a)(1)(ii).

Latch door pull box—Latch door pull boxes are active electro-mechanical devices not subject to an AMR.

Pneumatic actuators—Pneumatic actuators are active components not subject to an AMR.

Actuator housing—The actuator housing is part of the valve actuator which is an active assembly with no pressure boundary function; therefore, it is not subject to an AMR.

Dikes for oil spill confinement—There are no dikes for oil spill confinement within the scope of license renewal for fire protection.

Buried underground fuel oil tanks for emergency diesel generators—Buried underground Fuel oil tanks for the emergency diesel generators are addressed in LRA Section 2.3.3.13, "Fuel Oil."

Expansion tank—Expansion tank is not a component in the fire water system.

Fire water main loop valves—Fire water main loop valves are included in component type "valve body" and are included in Tables 2.3.3.11-IP2 and 2.3.3.11-IP3, with the AMR results provided in LRA Tables 3.3.2-11-IP2 and 3.3.2-11-IP3.

Post-indicator valves—Post-indicator valves are included in component type "valve body" and are included in Tables 2.3.3.11-IP2 and 2.3.3.11-IP3, with the AMR results provided in LRA Tables 3.3.2-11-IP2 and 3.3.2-11-IP3.

Jacket cooling water keep-warm pump and heater—The jacket cooling water keep-warm pump and heater are parts of the diesel engine assembly, which is an active assembly not subject to an AMR.

Lubricating oil collection system components for each reactor coolant pump—The lubricating oil collection system components for each reactor coolant pump are subject to an AMR and are addressed in LRA Section 2.3.3.12 and Tables 2.3.2-12-IP2 and 2.3.2-12-IP3, with the AMR results provided in LRA Tables 3.3.2-12-IP2 and 3.3.2-12-IP3.

Lubricating oil cooler—The lubricating oil cooler is a part of the fire pump diesel engine assembly, which is an active assembly not subject to an AMR.

Auxiliary lubricating oil makeup tank—The auxiliary lubricating oil makeup tank is not a component in the fire protection systems.

Rocker lubricating oil pump—The rocker lubricating oil pump is a part of the fire pump diesel engine assembly, which is an active component and not subject to an AMR.

Floor drains and curbs for fire-fighting water—Floor drains for fire-fighting water are addressed in LRA Section 2.3.3.18, "Plant Drains" and Tables 2.3.3-18-IP2 and 2.3.3-18-IP3 under component type "piping," with the AMR results provided in LRA Tables 3.3.2-18-IP2 and 3.3.2-18-IP3. Curbs are included in the structural

AMR under component types “floor slabs, interior walls and ceilings” (for concrete). They are included in LRA Table 2.4-3, with the AMR results provided in LRA Table 3.5.2-3.

Backflow prevention devices—Backflow prevention devices are addressed in LRA Section 2.3.3.18 and Tables 2.3.3-18-IP2 and 2.3.3-18-IP3 under the component type “valve body,” with the AMR results provided in LRA Tables 3.3.2-11-IP2 and 3.3.2-11-IP3.

Flame retardant coating for cables—Flame retardant coatings for cables are subject to an AMR and are included in the category of bulk commodities evaluated in the structural AMR. Flame retardant coatings are a subcomponent of component types “fire barrier penetration seal” and “fire stop.” These component types are included in LRA Table 2.4-4, with the AMR results provided in LRA Table 3.5.2-4.

Fire retardant coating for structural steel supporting walls and ceilings—Fire retardant coating for structural steel supporting walls and ceilings are subject to an AMR and are included in the structural AMR as component type “fire proofing.” This line item is included in LRA Table 2.4-4, with the AMR results provided in LRA Table 3.5.2-4.

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 “piping” line item provided in LRA Tables 2.3.3-11-IP2 and 2.3.3-11-IP3 does not list these components specifically, the applicant stated that it considers this line item to include the hose connections, pipe fittings, couplings, threaded connections, restricting orifices, interface flanges, and orifices. LRA Tables 3.3.2-11-IP2 and 3.3.2-11-IP3 provide the AMR results for these components. In addition, the applicant addressed floor drains in LRA Section 2.3.3.18, “Plant Drains,” and Tables 2.3.3-18-IP2 and 2.3.3-18-IP3 under component type “piping,” with AMR results provided in LRA Tables 3.3.2-18-IP2 and 3.3.2-18-IP3. The structural AMR includes curbs under component type “floor slabs, interior walls and ceiling” (for concrete) in LRA Table 2.4-3, with AMR results provided in LRA Table 3.5.2-3. Further, the applicant considers that some components in LRA Table 2.4-4, with AMR results in LRA Table 3.5.2-4, include certain components identified in the RAI. Specifically, the applicant indicated that (1) hose racks and interior fire hose stations are considered “fire hose reels,” (2) pipe supports are considered “piping supports,” (3) flame retardant coating for cables is considered a subcomponent of component types “fire barrier penetration seal” and “fire stop,” and (4) fire retardant coating for structural steel supporting walls and ceilings is considered “fire proofing.” The staff finds this portion of the applicant's response to RAI 2.3A.3.11-2 acceptable because it confirms that the components in question are within the scope of license renewal and subject to an AMR. In addition, the response also directed the staff to the AMR results in the LRA.

In its response, the applicant also confirmed that thermowells and expansion joints are a component type within the fire pump diesel exhaust system; the diesel-driven fire pump engine muffler is included in component type “silencer”; and the fire water main loop valves, post-indicator valves, and backflow prevention devices are included in component type “valve body” in LRA Tables 2.3.3-11-IP2 and 2.3.3-11-IP3, with the AMR results provided in LRA Tables 3.3.2-11-IP2 and 3.3.2-11-IP3. Filter housing is only associated with IP3 components shown on license renewal drawing LRA-9321-40903-0 and included in LRA Table 2.3.3-11-IP3, with the AMR results provided in LRA Table 3.3.2-11-IP3. LRA Section 2.3.3.13, "Fuel Oil," addresses buried underground fuel oil tanks for EDGs. Lubricating oil collection system components for each RCP are addressed in LRA Section 2.3.3.12 and Tables 2.3.3-12-IP2 and 2.3.3-12-IP3, with the AMR results provided in LRA Tables 3.3.2-12-IP2 and 3.3.2-12-IP3. The staff finds this portion of the applicant's response to RAI 2.3A.3.11-2 acceptable because it confirms that the components in question are within the scope of license renewal and subject to an AMR. Furthermore, the response directed the staff to the AMR results in the LRA.

The staff found that the applicant did not include the following components in the line item descriptions in the LRA: (1) heat-actuated devices, (2) tank heaters, (3) water motor alarm, (4) gear box housings, (5) turbocharger housing, (6) latch door pull box, (7) pneumatic actuators, (8) actuator housings, (9) jacket cooling water keep-warm pump and heater, (10) lubricating oil cooler, and (11) rocker lubricating oil pump. Because these components are active, they are not subject to an AMR.

The following components are not part of the fire protection systems (water) in IP2 and IP3: (1) heat exchanger (bonnet), (2) heat exchanger (shell), (3) heat exchanger (tube); (4) sight glass expansion tanks, (5) auxiliary lubricating oil makeup tanks, and (6) dikes for oil spill confinement. Since these components are not used in the fire protection system—water at IP2 and IP3, the staff finds that the applicant appropriately omitted them from the scope of license renewal.

Although they are within the scope of license renewal, flexible hoses are replaced at specified intervals. Therefore, the staff finds that flexible hoses are not subject to an AMR, in accordance with 10 CFR 54.21(a)(1)(ii).

The applicant determined that yard hose houses are not subject to an AMR because their failure will not result in a failure of the fire suppression function of the associated fire hydrant. Similarly, the applicant determined that chamber housings are not subject to an AMR because their failure will not result in a failure of the fire suppression function of the sprinkler system. The yard hose houses and chamber housings are passive, long-lived components that were identified as within the scope of license renewal. Therefore, the staff considers these components to be subject to an AMR, in accordance with 10 CFR 54.21(a)(1). This was identified as Open Item 2.3A.3.11-1.

Based on its review, the staff found the applicant's response to RAI 2.3A.3.11-2 partially acceptable because it resolved the staff's concerns regarding scoping and screening of fire protection system components listed in the RAI, with the exception of (a) yard hose houses and (b) chamber housings.

By the letter January 27, 2009, the applicant stated that yard hose houses for IP-2 are not a building; they are a metal cabinet storage location containing fire hoses and supporting tools (spanner, gated wyes and nozzles). The hose contained therein is subject to periodic inspection, testing and replacement in accordance with NFPA standards. Yard hose houses provide no function that supports 10 CFR 50.48 requirements: therefore, they are not in the scope of license renewal.

Chamber housings are small surge suppression volumes that function to minimize false actuation alarms due to system pressure surges. The chambers receive water from a small bypass line upon actuation of a deluge fire suppression system. When the chamber fills, water flow continues through the chamber to a drain line. Due to the limited amount of water flowing to the chamber housings, neither normal operation nor failure of the chamber housing would prevent satisfactory operation of the fire suppression system. In addition, the chamber housings shown on IP2 drawings are associated with deluge valves that do not perform a function that is credited for compliance with 10 CFR 50.48. The fire suppression systems with chamber housings serve maintenance areas and a file room in the technical support center.

The applicant clarified that yard fire hydrants are housed in small sheds; and chamber housings are small surge suppression volumes that function to minimize false actuation alarms due to system pressure surges. The staff determined that failure of these components, which is a second level support system, need not be considered in determining the SCs within the scope of the license renewal under 10 CFR 54.4(a)(3). The staff concludes that the above components were correctly excluded from the scope of license renewal. The staff's concern identified in Open Item 2.3A.3.11-1 has been resolved. Therefore, Open Item 2.3A.3.11-1 is closed.

2.3A.3.11.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. On the basis of its review, the staff concludes that the applicant has adequately identified the fire protection - water system 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).

2.3A.3.12 IP2 Fire Protection—Carbon Dioxide, Halon, and RCP Oil Collection Systems

2.3A.3.12.1 Summary of Technical Information in the Application

LRA Section 2.3.3.12 describes the fire protection—CO_2, Halon 1301 and RCP oil collection system, which consists of fixed fire suppression systems utilizing Halon 1301 as well as oil leakage collection for the RCPs. IP2 does not have a CO_2 fire suppression system within the scope of license renewal. The Halon 1301 systems consist of gas storage tanks and the necessary piping, valves, and instrumentation. The RCP oil collection system consists of drain pans, collection tanks, and the necessary piping, valves, and instrumentation to collect any leakage of the RCP lube oil system.

A fixed Halon fire suppression system meets 10 CFR 50.48 requirements for the cable spreading room as a total-flooding, manually-actuated system divided into four zones of discharge nozzles. The RCP oil collection system can collect lube oil from all potential pressurized and unpressurized RCP lube oil system leakage sites and drain it to a vented closed tank that can hold the required lube oil system inventory.

The fire protection Halon and RCP oil collection systems have no intended function under 10 CFR 54.4(a)(1). The scoping and screening methodology identified the following RCP oil collection system intended function, in accordance with 10 CFR 54.4(a)(2): "Maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function."

The scoping and screening methodology also identified the following Halon and RCP oil collection systems' intended functions, in accordance with 10 CFR 54.4(a)(3):

- Provide fixed automatic and manual fire suppression to extinguish fires in vital areas of the plant (10 CFR 50.48).
- Provide each RCP an oil collection system that is designed to contain and direct the oil to remote storage containers in the event of an oil leak.

LRA Tables 2.3.3-12-IP2 and 2.3.3-19-11-IP2 identify fire protection—CO_2, Halon 1301 and RCP oil collection system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.3.12.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.12, UFSAR Section 9.6.2, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

The staff also reviewed NRC fire protection SERs for IP2, dated November 30, 1977; February 3, 1978; January 31, 1979; October 31, 1980; August 22, 1983; March 30, 1984; October 16, 1984; September 16, 1985; November 13, 1985; March 4, 1987; January 12, 1989; and March 26, 1996.

The staff also reviewed IP2 commitments made in response to the requirements of 10 CFR 50.48 (i.e., an approved fire protection program), using its commitment documents associated with BTP APCSB 9.5-1 and Appendix A to BTP APCSB 9.5-1.

During its review of LRA Section 2.3.3.12, the staff identified areas in which additional information was necessary to complete its review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

In RAI 2.3A.3.12-1, dated October 24, 2007, the staff questioned why LRA Table 2.3.3-12-IP2 and 2.3.3-12-IP3 excluded several types of CO_2 and Halon 1301 fire suppression system components discussed in the fire protection SERs or the UFSAR or both and which are identified in the License renewal drawing as subject to an AMR (i.e., they are highlighted in brown). These components include the following:

- strainer housing
- pipe fittings
- pipe supports
- couplings
- odorizer
- threaded connections

- flexible hose
- latch door pull box
- pneumatic actuators

The staff requested that the applicant verify whether LRA Tables 2.3.3-12-IP2 and 2.3.3-12-IP3 should include the components listed above. If they are excluded from the scope of license renewal and not subject to an AMR, the staff requested that the applicant justify their exclusion.

In its response, dated November 16, 2007, the applicant provided the following:

> Strainer housings—Based on a review of LRA drawings D-8775-002-0, D-8775-004-0, D-8775-005-0 and 9321-24403-0, there are no strainer housings in the Halon systems.
>
> Pipe fittings—As stated in LRA Section 2.0 Page 2.0-1, the term "piping" may include pipe, pipe fittings (such as elbows and reducers), flow elements, orifices, and thermowells. Pipe fittings are subject to an AMR and included in LRA Tables 2.3.3-12-IP2 and 2.3.3-12-IP3, with AMR results provided in Tables 3.3.2-12-IP2 and 3.3.2-12-IP3, under the component type "piping."
>
> Pipe supports—Pipe supports are subject to an AMR and are included in the structural AMR as shown in LRA Table 2.4-4, under "component and piping supports."
>
> Couplings—As stated in LRA Section 2.0, Page 2.0-1, the term "piping" may include pipe, pipe fittings (such as elbows and reducers), flow elements, orifices, and thermowells. Couplings are considered to be pipe fittings, subject to an AMR and included in the "piping" line item in LRA Tables 2.3.3-12-IP2 and 2.3.3-12-IP3, with AMR results provided in Tables 3.3.2-12-IP2 and 3.3.2-12-IP3.
>
> Odorizer—As stated in LRA Section 2.0, Page 2.0-1, the term "piping" may include pipe, pipe fittings (such as elbows and reducers), flow elements, orifices, and thermowells. Odorizer housings are subject to an AMR and are included in component type "piping" in LRA Tables 2.3.3-12-IP2 and 2.3.3-12-IP3, with AMR results provided in Tables 3.3.2-12-IP2 and 3.3.2-12-IP3. The internals of the odorizer are active (short-lived components) subcomponents and not subject to an AMR.
>
> Threaded connections—As stated in LRA Section 2.0 Page 2.0-1, the term "piping" may include pipe, pipe fittings (such as elbows and reducers), flow elements, orifices, and thermowells. Threaded connections are pipe fittings subject to an AMR and included in the "piping" line item in LRA Tables 2.3.3-12-IP2 and 2.3.3-12-IP3, with AMR results provided in Tables 3.3.2-12-IP2 and 3.3.2-12-IP3.
>
> Flexible hose—There are no flexible hoses utilized in the in-scope Halon systems. LRA drawing D-8775-005-0 is based on a vendor drawing that indicates flex hoses at the gas cylinders. Flexible hoses are not used in the IP2 and IP3 configuration. Flexible hoses are utilized in the RCP oil collection system for IP2 and IP3 as indicated in Tables 2.3.3-12-IP2 and 2.3.3-12-IP3, with AMR results

provided in Tables 3.3.2-12-IP2 and 3.3.2-12-IP3. These hoses are stainless steel hoses that are not replaced on a specified frequency.

Latch door pull box—Latch door pull boxes are active electro-mechanical devices and not subject to an AMR.

Pneumatic actuators—Pneumatic actuators (in the form of gas operated pilot valves) are utilized in the in-scope Halon 1301 systems. Actuation is by means of active electrical devices which actuate pilot valves utilizing gas pressure as the motive force. The pilot valves and process valves are included under the component type "valve body" and are subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3A.3.12-1 acceptable. Although the description of the "piping" line item provided in LRA Tables 2.3.3-11-IP2 and 2.3.3-11-IP3 does not list these components specifically, the applicant stated that it considers pipe fittings, pipe supports, couplings, odorizer, and threaded connections to be included in LRA Tables 2.3.3-12-IP2 and 2.3.3-12-IP3 under the component type "piping" with the AMR results provided in LRA Tables 3.3.2-12-IP2 and 3.3.2-12-IP3.

The applicant has included pneumatic actuators in LRA Tables 2.3.3-12-IP2 and 2.3.3-12-IP3 under the component type "valve body," with the AMR results provided in LRA Tables 3.3.2-12-IP2 and 3.3.2-12-IP3. In similar license renewal reviews, components excluded from the list of components subject to an AMR and from the associated definition of a line item term, such as the "piping" line item, are often modified to include components that were not previously named, either in the component list or in the definition, for completeness. Because the applicant considers the line items specified to include these components, the staff finds that these components have been appropriately included within the scope of license renewal and identified as being subject to an AMR.

Further, the applicant noted that some components in LRA Table 2.4-4 are presented in LRA Table 3.5.2-4. Specifically, the applicant indicated that (1) hose racks and interior fire hose stations are considered "fire hose reels," (2) pipe supports are considered "piping supports," (3) flame retardant coating is considered a subcomponent of "fire barrier penetration seal" and "fire stop," and (4) fire retardant coating for structural steel supporting walls and ceilings is considered "fire proofing."

Also, the applicant confirmed that the Halon 1301 systems do not utilize flexible hoses, and these systems do not include strainer housings.

The staff found that the line item descriptions in the LRA do not include latch door pull boxes. The staff accepts the applicant's explanation that latch door pull boxes are active components and, therefore, not subject to an AMR. The staff's concern described in RAI 2.3A.3.12-1 is resolved.

2.3A.3.12.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the fire protection Halon 1301, and RCP oil collection 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).

2.3A.3.13 IP2 Fuel Oil Systems

2.3A.3.13.1 Summary of Technical Information in the Application

LRA Section 2.3.3.13 describes the fuel oil systems for IP2 and IP3 EDGs, the IP2 security diesel generator, IP2 and IP3 Appendix R diesel generators, and IP2 and IP3 fire protection diesel-driven fire pumps.

The IP2 fuel oil system code (i.e., the applicant's code for designating systems and boundaries) which includes the 1-million-gallon IP1 fuel oil tank and many of its associated components, but not the safety-related EDG fuel oil components, and has no safety-related components. The fuel oil system includes components that supply the bulk fuel oil to site components, including the house heating boiler and the bulk fuel oil supply to IP3. The IP1 fuel oil tank and its piping are not required to support fire diesel or EDG operation. These components have separate fuel oil tanks.

The fuel oil section includes the gas turbine system description because the only intended function of the gas turbine system for license renewal is performed by its fuel oil subsystem. The fuel supply for gas turbines in the IP2 gas turbine system supplements fuel oil storage for the IP2 and IP3 EDGs. This shared fuel storage consists of two onsite 30,000-gallon fuel oil tanks and a 200,000-gallon storage tank at the Buchanan Substation site. A 29,000-gallon minimum from these storage tanks is dedicated for EDG use. The tanks are not connected directly to the EDG fuel oil storage tanks, but trucking facilities can transfer oil within 1 day's notice.

Each diesel fuel oil storage and transfer system supplying fuel to the EDGs has its own fuel oil day tank, as well as an underground storage tank. The day tanks are within the diesel generator buildings. An engine-driven fuel oil pump feeds the fuel from the day tank to supply the engine. The day tank fills automatically during engine operation from its dedicated underground storage tank adjacent to the diesel generator building. Each underground storage tank has a motor-driven pump to transfer fuel to the day tank.

Independent diesel fuel oil storage and transfer systems supply fuel to the IP2 and IP3 fire protection diesel engines. The IP2 fuel oil storage tank, pump, and components are in the IP2 diesel fire pump house.

An independent diesel fuel oil storage and transfer system supplies fuel to the IP2 security diesel generator, which has its own fuel oil day tank within the security access building diesel generator room as well as an independent underground storage tank adjacent to that building.

An independent diesel fuel oil storage and transfer system supplies fuel to the IP2 SBO/Appendix R diesel generator from the gas turbine fuel oil storage tanks and transfer pumps in the oil room. The SBO/Appendix R diesel generator has its own day tank, which supplies fuel to the engine. The day tank fills automatically during engine operation from the storage tanks by the transfer pumps.

The fuel oil system and subsystems contain safety-related components relied on to remain functional during and following DBEs. They also contain nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the fuel oil system and subsystems perform functions that support fire protection and SBO.

LRA Tables 2.3.3-13-IP2 and 2.3.3-19-10-IP2 identify fuel oil system and subsystems component types within the scope of license renewal and subject to an AMR as well as their intended functions.

2.3A.3.13.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.13, UFSAR Sections 8.1, 8.2, and 8.2.3, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.3.13, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. For discussion and disposition of RAI 2.3A.3.13-1, dated February 13, 2008, see SER Section 2.3A.3 in the discussion of "Staff's RAIs."

2.3A.3.13.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI response, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has appropriately identified the fuel oil system 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).

2.3A.3.14 IP2 Emergency Diesel Generator System

2.3A.3.14.1 Summary of Technical Information in the Application

LRA Section 2.3.3.14 describes the EDG system, which supplies emergency shutdown power upon loss of all other alternating current auxiliary power and consists of three EDG sets, each with a diesel engine coupled to a 480-V generator. Each emergency diesel includes two redundant air motors for automatic starting, an air storage tank and compressor system, its own starting air subsystem, fuel oil subsystem, intake air subsystem, exhaust subsystem, lube oil subsystem, and jacket water cooling subsystem. The EDG system also includes ventilation equipment for the diesel generator building.

The EDG system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the EDG system performs functions that support fire protection.

Some of the valves in this system are parts of the SW system pressure boundary reviewed with the SW system (LRA Section 2.3.3.2). The fuel oil subsystem components are reviewed with fuel oil (LRA Section 2.3.3.13). A small number of components are reviewed with the city water system (LRA Section 2.3.3.17).

LRA Tables 2.3.3-14-IP2 and 2.3.3-19-9-IP2 identify EDG system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.3.14.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.14, UFSAR Section 8.2.3, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.3.14, the staff identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The discussion of the staff's RAIs in SER Section 2.3A.3 details the disposition of RAI 2.3A.3.14-2, dated February 13, 2008. The applicant responded to additional staff RAIs as discussed below.

In RAI 2.3A.3.14-1, dated December 7, 2007, the staff noted that a license renewal drawing for the IP2 jacket water to the EDGs identifies that the jacket water pumps for diesel engine Nos. 21, 22, and 23, respectively, are not subject to an AMR, in accordance with 10 CFR 54.21(a), because they are not long-lived components. The staff stated that SRP-LR, Table 2.3-2, "Examples of Mechanical Components Screening and Basis for Disposition," provides examples of passive, long-lived components, such as diesel engine jacket water skid-mounted equipment. To complete its review, the staff requested that the applicant confirm that the jacket water pumps are short-lived components and describe its method for periodic replacement.

In its response, dated January 4, 2008, the applicant stated that the IP2 EDG maintenance procedures specify that the jacket water pumps in question are scheduled for replacement every 16 years, in accordance with station maintenance procedures. Therefore, they are not subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3A.3.14-1 acceptable because it adequately explained that the practice of replacing the jacket water pumps meets the intent of 10 CFR 54.21(a)(1)(ii) for short-lived components and that the maintenance procedures ensure the pumps' periodic replacement. Therefore, the staff agrees that the jacket water pumps are not subject to an AMR. The staff's concern described in RAI 2.3A.3.14-1 is resolved.

In RAI 2.3A.3.14-2, dated December 7, 2007, the staff noted that license renewal drawings for the IP2 and IP3 EDG jacket water cooling systems and EDG fuel oil systems identify multiple "flexible conn [connections]" as not being long-lived components; therefore, they are not subject to an AMR. In LRA Section 2.1.2.1.3, "Mechanical System Drawings," the applicant stated, "Flexible elastomer hoses/expansion joints that are periodically replaced (not long-lived) and therefore not subject to aging management review are indicated as such on the drawings." Screening guidance provided in Table 2.1-3 of the SRP-LR describes items considered to be consumables as short lived and subject to periodic replacement. The staff requested that the applicant describe the programs that manage the replacement activities for these flexible connections.

In its response, dated January 4, 2008, the applicant stated that EDG maintenance procedures specify that the flexible connections in the EDG jacket water and fuel oil systems are components that are periodically replaced. The applicant further explained that, in accordance with 10 CFR 54.21(a)(1)(ii), components that are subject to periodic replacement based on a specified time period are not subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3A.3.14-2 acceptable because it adequately explained that flexible connections are periodically replaced, as directed by EDG maintenance procedures. Therefore, these connections are not subject to an AMR, in accordance with 10 CFR 54.21(a)(1)(ii). The staff agrees that the flexible connections designated as not long lived are not subject to an AMR. The staff's concern described in RAI 2.3A.3.14-2 is resolved.

In RAI 2.3.0-2, dated February 13, 2008, the staff noted that the license renewal drawings for the IP2 and IP3 EDG jacket water cooling systems have components marked "Not a Long Lived Component." The staff noted that SRP-LR Section 2.1.3.2.2 describes long-lived SCs as those that are not subject to periodic replacement based on a qualified life or specified time period. Furthermore, the LRA states that replacement programs may be based on vendor recommendations, plant experience, or any means that establish a specific replacement frequency under a controlled program.

Previous LRAs typically have not designated pumps, motors, and heat exchangers as not long lived. Therefore, the staff requested that the applicant do the following:

(a) Identify the component types serviced by the CCW that are shown as "Not a Long Lived Component."

(b) Provide a basis for designating these components as not long lived, including details as to how the "qualified life" of the components was established, a description of the program under which aging management activities for the components are performed, and any available plant-specific operating experience confirming the effectiveness of management activities.

In its response, dated March 12, 2008, the applicant identified the components designated as not long lived in the EDG jacket cooling water as flexible connections and pump casings. The applicant explained that these components are replaced on an established frequency, in accordance with vendor recommendations. The applicant stated that the plant-specific operating experience did not identify any instances of EDG jacket cooling water flexible connection or pump failures, thus confirming the effectiveness of the replacement activities.

Based on its review, the staff finds the applicant's response to RAI 2.3.0-2 for the EDG system acceptable because it adequately provides the basis for the applicant's designation of the EDG jacket cooling water flexible connections and pump casings as short-lived components, in accordance with the guidance found in SRP-LR Section 2.1.3.2.2. The staff's concern described in RAI 2.3.0-2 is resolved.

2.3A.3.14.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has appropriately identified the EDG system 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).

2.3A.3.15 IP2 Security Generator System

2.3A.3.15.1 Summary of Technical Information in the Application

LRA Section 2.3.3.15 describes the security system, which provides plant security equipment, most of which is not mechanical. The security diesel generates back-up electrical power to security equipment, including lighting of the operator access and egress routes for Appendix R events.

The security system performs functions that support fire protection.

The fuel oil subsystem components are reviewed with fuel oil (LRA Section 2.3.3.13).

LRA Table 2.3.3-15-IP2 identifies security system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.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.

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

2.3A.3.15.3 Conclusion

The staff reviewed the LRA to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the security generator system 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).

2.3A.3.16 IP2 Appendix R Diesel Generator System

2.3A.3.16.1 Summary of Technical Information in the Application

By letter dated April 30, 2008, the applicant amended its LRA to reflect the installation of the IP2 SBO/Appendix R diesel generator.

LRA Section 2.3.3.16, as amended, describes the SBO/Appendix R diesel generator system, which supplies power to selected equipment and power supplies relied on in Appendix R and SBO events. With sufficient power for safe-shutdown loads, the SBO/Appendix R diesel generator is the source of alternate alternating current power for IP2, as required by 10 CFR 50.63. The SBO/Appendix R diesel generator provides power during Appendix R and SBO events. The IPA for license renewal included the SBO/Appendix R diesel generator within the scope of license renewal.

The SBO/Appendix R diesel is located inside the IP1 turbine building. The SBO/Appendix R diesel generator is designed to operate upon a complete loss of power. The SBO/Appendix R diesel generator includes batteries, a battery charger, jacket water heater and cooler, turbochargers, aftercoolers, aftercooler coolers, jacket water pump, lube oil cooler, lube oil pump, and necessary filters and piping. The SBO/Appendix R diesel generator can supply safe-shutdown loads through the 6.9-kilovolt (kV) distribution system and the emergency 480-V buses and motor control centers or the turbine building switchgear and motor control centers.

The SBO/Appendix R diesel generator system performs functions that support fire protection and SBO.

Fuel oil supply components are evaluated with fuel oil (LRA Section 2.3.3.13). Appendix R diesel generator system ventilation is evaluated with the HVAC systems (LRA Section 2.3.3.8).

LRA Table 2.3.3-16-IP2 identifies SBO/Appendix R diesel generator system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.3.16.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.16 and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

The staff reviewed the amended LRA, changes to the UFSAR, and two license renewal drawings to determine whether the applicant failed to identify any SSCs typically found within the scope of license renewal. SER Sections 3.3.2.1 and 3.3A.2.3.13 document the staff's evaluation of the amended AMR results for the SBO/Appendix R diesel generator system.

2.3A.3.16.3 Conclusion

The staff reviewed the LRA, the UFSAR, the LRA amendment, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the SBO/Appendix R diesel generator system 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).

2.3A.3.17 IP2 City Water

2.3A.3.17.1 Summary of Technical Information in the Application

LRA Section 2.3.3.17 describes the city water system, which supplies water to various plant components. Originally installed for IP1, the city water system now functions for all three units. The city water system code includes IP1 and IP2 components. Water for the system comes from the Village of Buchanan. Within the boundary of the plant system are the supply piping from the water main, pressure-regulating valves, strainers, water meters, and backflow preventers. After metering, the water flows to a manifold which directs it to either the plant or the 1.5-million-gallon city water storage tank. The plant uses city water to supply fire protection systems, the SBO/Appendix R diesel generator, sanitary and drinking facilities (e.g., emergency showers, eye wash stations, humidifiers, hose connections, sinks, water coolers, water heaters, and lavatories), radiation monitors for purging, and various equipment for makeup or cooling; to supply backup to the AFW pumps; and to serve other emergency purposes. The system is also a CCW backup for bearing and seal water cooling for the charging, safety injection, and RHR pumps.

The city water system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the city water system performs functions that support fire protection and SBO.

LRA Section 2.3.4.5 reviews components that support safe shutdown in the event of an auxiliary feed pump room fire.

LRA Tables 2.3.3-17-IP2 and 2.3.3-19-7-IP2 identify city water system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.3.17.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.17, UFSAR Sections 9.6.3 and 10.2.6.3, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.3.17, the staff identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

In RAI 2.3A.3.17-1, dated December 7, 2007, the staff noted that the applicant highlighted a small portion of 2-inch city water line No. 35 on a license renewal drawing in purple, indicating that it is within the scope of license renewal and subject to an AMR for the city water system. The staff also noted that the identified piping, which is shown in a detail, makes no reference to a continuation drawing, and the detailed area of the drawing references another drawing, which the applicant did not include in the LRA.

The staff questioned whether this piping section contains additional components that should be included within the scope of license renewal. Therefore, the staff requested that the applicant either explain why the LRA did not list the parent drawing for the detailed area under license renewal drawings for the city water system or provide the parent drawing and any other continuation drawings that contain components within the scope of license renewal.

In its response, dated January 4, 2008, the applicant stated that the parent drawing is an equipment general arrangement drawing that includes all of the components shown on the drawing which included the detail. The applicant further stated that no additional components are shown on the parent drawing, and the section of 2-inch city water line No. 35 in the detail is continued on another license renewal drawing that shows the "ghost image" of a valve connecting to the 2-inch city water line No. 35.

Based on its review, the staff finds the applicant's response to RAI 2.3A.3.17-1 acceptable because it adequately explained that the parent drawing is an equipment general arrangement drawing that includes all of the components shown in the detail on the license renewal drawing. The staff finds no need for the applicant to bring the additional components for the city water system within the scope of license renewal. Although not identified on the license renewal drawing, the applicant explained that the continuation of the 2-inch city water line No. 35 appears on another license renewal drawing, which had been provided to the staff with the LRA. The staff's concern described in RAI 2.3A.3.17-1 is resolved.

In RAI 2.3A.3.17-2, dated December 7, 2007, the staff stated that a license renewal drawing shows piping highlighted in purple, indicating that the piping for the city water system is within the scope of license renewal and subject to an AMR.

The staff noted that, at four fire protection system valves on the drawing, the system designation changes from the city water system to the fire protection system. Additionally, the staff noted that, at one other fire protection system valve on the drawing, the system designation changes from the city water system to the AFW system. Although the identified system designation changes, the highlighting remains purple. The staff noted that the components indicated should be subject to an AMR under the scope of the city water system. The staff requested that the applicant explain how the color coding applies to the multiple systems identified above.

In its response, dated January 4, 2008, the applicant stated that the fire protection system, which is highlighted in green, is a high-pressure water system that serves structures and strategically located hydrants. The applicant further explained that the city water system, which is highlighted in purple, is a low-pressure system that provides backup to the high-pressure system and includes the low-pressure hydrants. The applicant explained that components in both systems are used for fire protection and that, when performing scoping and screening of components for license renewal, the applicant included components that are part of the low-pressure city water system flowpath and required to accomplish city water system functions in the city water system, regardless of their component identification or the system designator shown on the drawing. Further, the applicant explained that it included components that are part of the high-pressure fire protection system flowpath and required to accomplish fire protection system functions in the fire protection system, regardless of their component identification or the system designator shown on the drawing. The applicant also stated that the system designators shown on the license renewal drawings do not define system boundaries, thus ensuring that all components required to accomplish system functions are included within the scope of license renewal. The applicant included the fire protection valves as part of the city water system with a pressure boundary intended function because they are fed by the low-pressure city water system and are required to accomplish the city water system functions identified in LRA Section 2.3.3.17.

Based on its review, the staff finds the applicant's response to RAI 2.3A.3.17-2 acceptable because it adequately explained that system designators shown on the license renewal drawings do not define system boundaries. The applicant included the fire protection valves as part of the city water system with a pressure boundary intended function because they are fed by the low-pressure city water system and are needed to accomplish the city water system functions related to fire protection. The staff's concern described in RAI 2.3A.3.17-2 is resolved.

In RAI 2.3A.3.17-3, dated December 7, 2007, the staff stated that, in the upper left corner of a license renewal drawing for the city water system, two 6-inch pipe lines are shown with a fire protection designation highlighted in purple, indicating that they are within the scope of license renewal and subject to an AMR. The staff requested that the applicant explain why the two fire protection lines are highlighted in purple (indicating that they are part of the city water system for license renewal) instead of green (indicating that they are part of the fire protection—water system).

In its response, dated January 4, 2008, the applicant stated that the fire protection system, which is highlighted in green, is a high-pressure water system that serves structures and strategically located hydrants. The city water system, which is highlighted in purple, is a low-pressure system that provides backup to the high-pressure system and includes the low-pressure hydrants. The applicant further explained that it included components that are part of the high-pressure fire protection system flowpath and required to accomplish fire protection system functions in the fire protection system, regardless of their component identification or the system designator shown on the drawing. The applicant also explained that the system designators shown on the license renewal drawings do not define system boundaries.

Based on its review, the staff finds the applicant's response to RAI 2.3A.3.17-3 acceptable because it adequately explained that the fire protection lines are within the scope of license renewal as part of the city water system, and they have a pressure boundary intended function. The fire protection lines are fed by the low-pressure city water system and are needed to accomplish the city water system functions related to fire protection. Therefore, the staff's concern described in RAI 2.3A.3.17-3 is resolved.

In RAI 2.3A.3.17-4, dated December 7, 2007, the staff stated that a license renewal drawing shows a short piece of piping for the city water system highlighted in purple, indicating that it is within the scope of license renewal and subject to an AMR. The staff noted that this short piece of city water system piping refers to two drawings for upstream piping. Since this short piece of city water system piping is within the scope of license renewal and continues onto the two upstream drawings, these two drawings should also have city water system piping within the scope of license renewal. However, the staff noted that the applicant did not list these two drawings in the LRA as license renewal drawings for the IP2 and IP3 city water system. The staff requested that the applicant explain why it had not listed the two referenced drawings in the LRA under license renewal drawings for the city water system.

In its response, dated January 4, 2008, the applicant stated that the two referenced drawings are not system flow diagrams, but equipment general arrangement drawings, which were not clear enough to use as license renewal drawings. The applicant further explained that it reviewed these two drawings to confirm that all components shown on them that are required to accomplish city water system functions were included within the scope of license renewal and subject to an AMR. The applicant concluded that the only components shown on these drawings are piping and 11 valves, all of which are within the scope of license renewal and subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3A.3.17-4 acceptable because it adequately explained that the two drawings are equipment general arrangement drawings for which a review was performed to confirm that all components shown are required for city water system functions and were included within the scope of license renewal and subject to an AMR. The staff understands that the only components shown on these two drawings are piping and 11 valves, which are already within the scope of license renewal and subject to an AMR. The staff's concern described in RAI 2.3A.3.17-4 is resolved.

In RAI 2.3A.3.17-5, dated December 7, 2007, the staff noted that, in the LRA, the applicant stated that the IP2 city water system has the intended function under 10 CFR 54.4(a)(3) of providing a supply of water to fire protection system components, including the fire pumps, fire hydrants, hose reel stations inside containment, fire water tank, and various sprinkler and deluge systems. The staff also noted that a license renewal drawing shows piping for the city water system highlighted in blue, indicating that it is within the scope of license renewal and subject to an AMR. The piping continues onto three additional drawings for downstream piping, which are not listed in the LRA. The staff noted that this additional piping and associated components are necessary for the city water system to accomplish its intended function to supply water from the IP2 city water system to the hose reel stations inside containment. The staff was concerned that the additional drawings might show city water system components that were not identified in the LRA. The staff requested that the applicant provide the three drawings and any other drawings, as necessary, showing the LRA scope of the IP2 city water system.

In its response, dated January 4, 2008, the applicant stated that the three drawings referenced are not system flow diagrams, but equipment general arrangement drawings, which were not clear enough to use as license renewal drawings. The applicant explained that it reviewed these three drawings to confirm that all of the components shown on them that are required to accomplish city water system functions were included within scope of license renewal and subject to an AMR. The only components shown on these drawings are piping and 19 valves, which are within the scope of license renewal and subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3A.3.17-5 acceptable because it adequately explained that the three drawings are equipment general arrangement drawings for which a review was performed to confirm that all the components shown on them that are required for city water system functions were included within the scope of license renewal and subject to an AMR. The staff understands that the only components shown on these three drawings are piping and 19 valves, which are already within the scope of license renewal and subject to an AMR. The staff's concern described in RAI 2.3A.3.17-5 is resolved.

In RAI 2.3A.3.17-6, dated December 7, 2007, the staff stated that a license renewal drawing for the city water system showed a fire hydrant highlighted in purple, indicating that it is within the scope of license renewal and subject to an AMR because it supports an intended function, in accordance with 10 CFR 54.4(a). The staff noted that the LRA component table for the city water system does not include the component type "hydrant." The staff stated that 10 CFR 54.21(a)(1) requires that the applicant identify and list those components subject to an AMR. The staff requested that the applicant identify where it evaluated the hydrants in the IP2 city water system for aging management.

In its response, dated January 4, 2008, the applicant stated that the site component database identifies the hydrants in the IP2 city water system as valves, and this designation was maintained during the AMR process. The applicant further explained that it included the hydrants in component type "valve body" in LRA Table 2.3.3-17-IP2, with AMR results provided in LRA Table 3.3.2-17-IP2.

Based on its review, the staff finds the response to RAI 2.3A.3.17-6 acceptable because it adequately explained that the applicant's site component database identifies the hydrants in the IP2 city water system as valves. The staff noted that the applicant has included hydrants in the component type "valve body" in the LRA component table and AMR results table for the IP2 city water system. The staff's concern described in RAI 2.3A.3.17-6 is resolved.

2.3A.3.17.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has appropriately identified the city water system 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).

2.3A.3.18 IP2 Plant Drains

2.3A.3.18.1 Summary of Technical Information in the Application

LRA Section 2.3.3.18 describes the plant drains, which are passive fire protection features required for adequate protection of safety-related equipment from water damage in areas with fixed-suppression systems. Plant drain components also prevent drain systems in areas with combustible materials from spreading fires into other areas of the plant. Some plant drains protect safety-related equipment from flooding effects.

Various systems include plant drain components, but, for the purposes of this evaluation, all plant drain components are grouped. SRP-LR Section 2.1.3.1 allows the grouping of similar components from various plant systems into a single, consolidated evaluation.

Both the fire protection and waste disposal systems include plant drain components. The waste disposal system collects and processes all potentially radioactive primary plant wastes, both gaseous and liquid, for removal from the site. The system collects, compresses, stores, samples, and releases gaseous waste from the primary and auxiliary systems. Gases vented to the vent header flow to the waste gas compressor suction header. One of the two compressors operates continuously, while the second unit serves as backup for peak load conditions. From the compressors, gas flows to one of the four large gas decay tanks. The header arrangement at the inlet allows the operator to fill the tank, reuse the gas, or discharge it to the environment. Six additional small gas decay tanks can be used during degassing of the reactor coolant before a cold shutdown. The system collects and processes liquid wastes throughout the plant from equipment, radioactive chemical laboratory, decontamination, demineralizer regeneration, and floor drains. Waste liquids drain by gravity to the waste holdup tank, the collection point for liquid wastes, or to the sump tank, the containment, or the PAB sumps, from which they are pumped to the waste holdup tank. The system sends the liquid waste holdup tank contents to the IP1 waste collection system and collects and transfers liquid drained from the RCS directly to the CVCS for processing.

The system includes the vent header, waste gas compressors, large and small waste gas decay tanks, waste gas analyzer, pumps, collection tanks, station drainage piping, floor drains, instruments and controls, piping, valves, several containment penetrations and accompanying isolation components, and piping, valves, instruments and controls to monitor condensation from the containment fan cooler units.

The plant drains system contains safety-related components relied on to remain functional during and following DBEs. The system also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the plant drains system performs functions that support fire protection.

A small number of waste disposal system components are reviewed with the CS system (LRA Section 2.3.2.2), the safety injection system (LRA Section 2.3.2.4), the city water system (LRA Section 2.3.3.17), the primary water makeup system (LRA Section 2.3.3.7), the CCW systems (LRA Section 2.3.3.3), and the RCS pressure boundary (LRA Section 2.3.1.3).

LRA Tables 2.3.3-18-IP2 and 2.3.3-19-42-IP2 identify plant drains system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.3.18.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.18, UFSAR Section 11.1, and a license renewal drawing using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.3.18, the staff identified an area in which additional information was necessary to complete its review of the applicant's scoping and screening results. The discussion of the staff's RAIs in SER Section 2.3A.3 details the disposition of RAI 2.3A.3.18-1, dated February 13, 2008.

2.3A.3.18.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI response, and a drawing to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has appropriately identified the plant drains system 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).

2.3A.3.19 IP2 Miscellaneous Systems in Scope for 10 CFR 54.4(a)(2)

2.3A.3.19.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.19, "Miscellaneous Systems In Scope for (a)(2)," the applicant described those systems that it included within the scope of license renewal with the potential for physical interaction with safety-related components, as required by 10 CFR 54.4(a)(2), and described the components in these systems subject to an AMR. LRA Table 2.3.3-19-A-IP2 lists all of these systems, as well as the LRA section in which the applicant evaluated these systems. LRA Section 2.3.3.19 describes in detail those systems without correlating LRA sections, which include the following:

- boiler blowdown
- chemical feed
- house service boiler
- intake structure system
- ignition oil
- integrated liquid waste handling
- main generator
- main turbine
- miscellaneous
- nuclear service grade makeup

- post-accident containment air sample
- post-accident containment vent (retired in place)
- primary sampling
- radiation monitoring
- secondary sampling
- technical support center diesel
- chlorination (added by applicant by letter dated February 13, 2008)

Also in LRA Section 2.3.3.19, the applicant identified the following IP2 systems that were not reviewed for 10 CFR 54.4(a)(2) for spatial interaction because the applicant included all of the system's passive mechanical components as (a)(1), functional (a)(2), or (a)(3):

- AFW
- containment cooling and filtration
- CCW
- control rod drive
- CS system
- electrical penetrations
- fuel and core component handling
- in-core instrumentation
- isolation valve seal water

The following briefly describes the IP2 systems included within the scope of license renewal based only on the criterion of 10 CFR 54.4(a)(2) and subject to an AMR.

Chemical Feed. The chemical feed system provides the means to add chemicals to secondary water systems for proper water chemistry control. LRA Table 2.3.3-19-3-IP2 identifies the chemical feed system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Intake Structure System. The intake structure system provides coarse filtering of the Hudson River water supplied to the CW system and the SW system. The system also includes mechanical components associated with the chlorine and hypochlorite addition subsystems. LRA Table 2.3.3-19-8-IP2 identifies the intake structure system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Main Generator. The main generator system produces the primary electrical output of the unit. The system includes the main generator, its supporting auxiliaries, and components in the stator cooling water and hydrogen seal oil systems. LRA Table 2.3.3-19-15-IP2 identifies the main generator system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

House Service Boiler. The house service boiler system produces steam for plant heating via the auxiliary steam system. The system includes the house service boilers and components in the fuel oil, FW, and condensate collection systems. LRA Table 2.3.3-19-16-IP2 identifies the house service boiler system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Ignition Oil. The ignition oil system supplies ignition oil to the house service boilers. Most of the ignition oil components are associated with the house service boiler system. LRA

Table 2.3.3-19-20-IP2 identifies the ignition oil system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Integrated Liquid Waste Handling. The integrated liquid waste handling system processes liquid waste collected by the waste disposal system. LRA Table 2.3.3-19-21-IP2 identifies the integrated liquid waste handling system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Miscellaneous. The applicant created the miscellaneous system for the purpose of license renewal to group together various structural, electrical, and mechanical components that were not described elsewhere. LRA Table 2.3.3-19-24-IP2 identifies the miscellaneous system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Nuclear Service Grade Makeup. The nuclear service grade makeup system supplies water to various service systems. The system includes components of the IP1 water treatment facility. LRA Table 2.3.3-19-25-IP2 identifies the nuclear service grade makeup system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Post-Accident Containment Air Sample. The post-accident containment air sample system provides a means to monitor hydrogen concentration inside containment following an accident. Based upon a recent license amendment (License Amendment No. 243), hydrogen monitoring is no longer required as a safety function; however, the system contains component in scope of license renewal under 10CFR 54.4 (a)(2). LRA Table 2.3.3-19-26-IP2 identifies the post-accident containment air sample system component types within the scope of license renewal and subject to an AMR as well as their intended functions.

Post-Accident Containment Vent. The post-accident containment vent system backs up the hydrogen recombiner to reduce post-LOCA hydrogen concentration in containment atmosphere. Based upon a recent license amendment (License Amendment No. 243), the hydrogen recombiner is no longer required as a safety function; however, the system contains component in scope of license renewal under 10CFR 54.4 (a)(2). LRA Table 2.3.3-19-27-IP2 identifies post-accident containment vent system component types within the scope of license renewal and subject to an AMR as well as their intended functions.

Primary Sampling. The primary sampling system performs high-radiation sampling and in-line monitoring and laboratory analysis of representative samples under normal or post-accident conditions. Some of the primary sampling system components support and are reviewed with other systems (e.g., RHR (LRA Section 2.3.2.1), safety injection (LRA Section 2.3.2.4), and containment penetrations (LRA Section 2.3.2.5)). LRA Table 2.3.3-19-28-IP2 identifies primary sampling system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Radiation Monitoring. The radiation monitoring system warns of any radiation health hazard and any plant malfunction that might cause health hazards or plant damage. Some of the radiation monitoring system components support, and are reviewed with, other systems (e.g., SW system (LRA Section 2.3.3.2) and containment penetrations (LRA Section 2.3.2.5)). LRA Table 2.3.3-19-31-IP2 identifies radiation monitoring system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Boiler Blowdown. The boiler blowdown purification system collects and stores or processes blowdown from an SG with a primary-to-secondary leak. LRA Table 2.3.3-19-34-IP2 identifies boiler blowdown system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Secondary Sampling. The secondary sampling system continuously samples and analyzes plant secondary systems. The system has components necessary to collect and transport samples to the sampling stations located in the turbine building. LRA Table 2.3.3-19-38-IP2 identifies secondary sampling system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Technical Support Center Diesel. The technical support center diesel system backs up the power supply to the technical support center. The technical support center diesel system includes the diesel generator, fuel oil supply, and supporting instruments and controls. LRA Table 2.3.3-19-40-IP2 identifies technical support center diesel system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Main Turbine. The main turbine system receives steam from the SGs, converts a portion of the steam thermal energy to electricity from the main generator, and supplies extraction steam for FW heating. LRA Table 2.3.3-19-41-IP2 identifies main turbine system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Chlorination (added by applicant by letter dated February 13, 2008). The chlorination system provides sodium hypochlorite to the intake bays to limit microorganism fouling in these bays and in the systems that use raw water. LRA Table 2.3.3-19-44-IP2 identifies chlorination system component types within the scope of license renewal and subject to an AMR, as well as their intended functions. SER Sections 3.3.2.1 and 3.3A.2.3.36 document the staff's review of the AMR results.

2.3A.3.19.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.19 and the following UFSAR (IP2) or safety analysis report (SAR) (IP1) Sections that were associated with these systems:

• boiler blowdown[1]	UFSAR Section 10.2.1.5
• chemical feed[1]	UFSAR Section 10.2.6.4
• main generator[1]	UFSAR Section 8
• house service boiler[1]	UFSAR Section 9.6.5
• integrated liquid waste handling[1]	SAR Section 3.7.3 and UFSAR Section 11.1.2.1
• main turbine[1]	UFSAR Section 10.2.2
• nuclear service grade makeup[2]	SAR Section 3.7.2
• post-accident containment air sample[2]	UFSAR Section 6.8.2.3
• post-accident containment vent (retired in place)[2]	UFSAR Section 6.8.2.2
• primary sampling[2]	UFSAR Section 9.4
• radiation monitoring[2]	UFSAR Section 11.2.3

[1] The staff conducted a simplified Tier 1 system review of these systems, as described in SER Section 2.3.
[2] The staff conducted a detailed Tier 2 system review of these systems, as described in SER Section 2.3.

•	secondary sampling[1]	UFSAR Section 9.4
•	miscellaneous[2]	UFSAR Sections 5.1.9, 5.1.11, and 5.2.2
•	intake structure system[1]	—
•	ignition oil[1]	—
•	technical support center diesel[1]	—
•	chlorination[1]	—

For those systems receiving a simplified Tier 1 evaluation, the staff reviewed the applicable LRA sections and UFSAR or SAR sections (if applicable) using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. For those systems receiving a detailed Tier 2 evaluation, the staff reviewed the applicable LRA sections, UFSAR or SAR sections (if applicable), and license renewal drawings (system components are shown on other associated system drawings). Based on information provided in the UFSAR or SAR and LRA, the staff evaluated the system functions described in LRA Section 2.3.3.19 to verify that the applicant had not omitted from the scope of license renewal any components with intended functions, as required by 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 it had not omitted any passive and long-lived components subject to an AMR, in accordance with 10 CFR 54.21(a)(1).

The staff reviewed the list of IP2 systems the applicant identified in LRA Section 2.3.3.19 as not having any components in scope for 10 CFR 54.4(a)(2) for spatial interaction because they were already included in scope under 10 CFR 54.4(a)(1), functional (a)(2), or (a)(3). In RAI 2.3A.2.2-1, dated February 13, 2008, the staff requested the applicant to explain why piping segments directly attached to IP2 CS system (a)(1) piping were not highlighted on boundary drawings to show included in scope for license renewal. The staff's review of the applicant's response, dated March 12, 2008, is documented in SER Section 2.3A.2.2.2.

In RAI 2.1-1, dated January 14, 2008, the staff asked the applicant to provide a technical basis for excluding nonsafety-related systems located in proximity to safety-related systems from the scope of license renewal. In its response, dated February 13, 2008, the applicant provided an evaluation of these systems and amended the LRA to include the IP2 chlorination system within the scope of license renewal under 10 CFR 54.4(a)(2). Additionally, the applicant added LRA Table 2.3.3-19-44-IP2 to identify the component types subject to an AMR.

During its review, the staff noted the applicant did not specifically identify components within the scope of license renewal under 10 CFR 54.4(a)(2) on the license renewal drawings. To determine that the applicant did not omit any components from scope under 10 CFR 54.4(a)(2), the staff used a sampling approach, as recommended in SRP-LR Section 2.3.3.1. In multiple RAIs, dated February 13, 2008, the staff asked the applicant to verify that various segments of selected systems were included in scope under 10 CFR 54.4(a)(2). This sampling approach enabled the staff to confirm that the applicant had properly implemented its methodology for identifying nonsafety-related portions of systems with a potential to adversely affect safety-related functions, in accordance with 10 CFR 54.4(a)(2).

In its response, dated March 12, 2008, the applicant stated that all components identified by the staff on the license renewal drawings are within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2), and subject to an AMR. Based on a review of the applicant's response, the staff finds that the applicant has adequately identified the components required to be within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2), as well as those subject to an AMR.

2.3A.3.19.3 Conclusion

For each system described above, the staff reviewed LRA Section 2.3.3.19, the applicable UFSAR or SAR section, and license renewal drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found instances in which the applicant omitted systems and components that should have been included within the scope of license renewal. The applicant has satisfactorily resolved these issues as discussed in the preceding staff evaluation. On the basis of its review, the staff finds that, for all of the systems identified in LRA Section 2.3.3.19, the applicant has appropriately identified the 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).

2.3A.4 Scoping and Screening Results: Steam and Power Conversion Systems Unit 2

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:

- 2.3.4.1, "Main Steam"
- 2.3.4.2, "Main Feedwater"
- 2.3.4.3, "Auxiliary Feedwater"
- 2.3.4.4, "Steam Generator Blowdown"
- 2.3.4.5, "IP2 AFW Pump Room Fire Event"
- 2.3.4.6, "Condensate"

SER Sections 2.3A.4.1–2.3A.4.6, respectively, describe the staff's review of the IP2 systems described in LRA Sections 2.3.4.1–2.3.4.6. The staff's findings for these systems are discussed below.

2.3A.4.1 IP2 Main Steam System

2.3A.4.1.1 Summary of Technical Information in the Application

LRA Section 2.3.4.1 describes the MS system, which conducts steam from the four SGs inside the containment structure to the turbine generator unit in the turbine generator building. The system has four MS pipes, one from each SG to the turbine stop and control valves, connected near the turbine. Each steam pipe has a main steam isolation valve (MSIV) and a non-return valve outside the containment. There are five code safety valves and one PORV on each MS line outside the reactor containment and upstream of the isolation and non-return valves. A flow venturi upstream of the isolation valve measures steam flow. Steam pressure is also measured upstream of the isolation valve. The MS system supplies steam to the main boiler FW pump turbines and the AFW pump turbine. The system includes the main boiler FW pump turbines and the turbine steam bypass and low-pressure steam dump systems, which channel excess steam flow to the condenser. The steam generator blowdown (SGBD) flowpath also includes MS system components.

The MS system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the MS system performs functions that support fire protection and SBO.

Main steam components in the SGBD flowpath are reviewed with the SGBD system (LRA Section 2.3.4.4). Components supporting the AFW system are reviewed with the AFW system (LRA Section 2.3.4.3). Components that support safe shutdown in a fire in the auxiliary feed pump room are evaluated in AFW pump room fire event (LRA Section 2.3.4.5). A small number of components are reviewed with the compressed air systems (LRA Section 2.3.3.4).

LRA Tables 2.3.4-1-IP2 and 2.3.3-19-23-IP2 identify MS system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.4.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.1, UFSAR Section 10.2, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.4.1, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3A.4.1-1, dated December 7, 2007, the staff noted that license renewal drawings for the IP2 MS system show the following valves within the scope of license renewal and subject to an AMR: PCV-1134, PCV-1135, PCV-1136, PCV-1137, MS-1-21, MS-1-22, MS-1-23, MS-1-24, PCV-1120, PCV-1121, PCV-1122, PCV-1123, PCV-1124, PCV-1125, PCV-1126, PCV-1127, PCV-1128, PCV-1129, PCV-1130, and PCV-1131. The staff also noted that these valves are air operated and have associated air cylinders and air tubing that the applicant excluded from the scope of license renewal. Since some of these valves appear to rely on pressurized air (pneumatic operation) to change position and fulfill their intended function, the staff requested that the applicant explain why the instrument air system, its tubing, and associated solenoid-operated valves (SOVs) to the valves in question are not within the scope of license renewal, in accordance with 10 CFR 54.4(a).

In its response, dated January 4, 2008, the applicant stated that the air operators are active components; therefore, they are not subject to an AMR, in accordance with 10 CFR 54.21(a)(1)(i) and NEI 95-10, Appendix B. The applicant explained that the SOVs and air tubing associated with air-operated valves in the MS system are within the scope of license renewal, but are not subject to an AMR because the majority of the air-operated valves shown on the MS license renewal drawings to be within the scope of license renewal fail to their required position for accident mitigation. As such, these valves do not require pressurized air to fulfill their intended function, and pressure boundary of the air tubing is not necessary. The applicant stated that an exception is the atmospheric dump valves and MSIVs, which close on loss of air but are credited with being reopened, as necessary, in an accident scenario using standby nitrogen in bottles or compressed air stored in accumulators. The applicant explained that components used to reopen the MS system valves are subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3A.4.1-1 acceptable because it explained that, for most of the air-operated valves, a failure of the air supply system will not result in a loss of the intended function because the MS valves fail to their safe positions. This explanation is consistent with Section 5.2.3.1 of NEI 95-10, Revision 6, which governs fail-safe components. For those air-operated valves that rely on an air supply system (i.e., those MS system valves that do not fail to their safe position), the applicant included the passive pneumatic components (accumulator tanks, tubing, and valves) of those air-operated valves within the scope of license renewal, in accordance with 10 CFR 54.4(a); these components are subject to an AMR, in accordance with 10 CFR 54.21(a)(1). The staff's concern described in RAI 2.3A.4.1-1 is resolved.

2.3A.4.1.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI response, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has appropriately identified the MS system 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).

2.3A.4.2 IP2 Main Feedwater System

2.3A.4.2.1 Summary of Technical Information in the Application

LRA Section 2.3.4.2 describes the main FW system, which has two half-size, steam-driven main FW pumps that increase condensate pressure for delivery through the final stage of FW heating and the FW regulating valves to the SGs. The FW system includes the high-pressure FW heaters, the SGs, the piping and valves from the outlet of the main feed pumps through the heaters to the SGs, and the main feed pump turbine drip tank drain pumps. The main feed pumps are part of the condensate system, and the main feed pump turbines are part of the MS system.

The main FW system contains safety-related components relied on to remain functional during and following DBEs. The failure of nonsafety-related SSCs in the main FW system could prevent the satisfactory accomplishment of a safety-related function. In addition, the main FW system performs functions that support fire protection.

The SGs and secondary-side instrumentation piping and valves are reviewed with the SGs (LRA Section 2.3.1.4). Components that support safe shutdown in the auxiliary feed pump room fire are evaluated in LRA Section 2.3.4.5. System components containing air are reviewed with the compressed air systems (LRA Section 2.3.3.4).

LRA Tables 2.3.4-2-IP2 and 2.3.3-19-12-IP2 identify main FW system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.2, UFSAR Section 10.2.6, and a license renewal drawing using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

The staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant had not omitted from the scope of license renewal any components with intended functions, as required by 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 and long-lived components subject to an AMR, in accordance with 10 CFR 54.21(a)(1).

During its review of LRA Section 2.3.4.2, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3A.4.2-1, dated December 7, 2007, the staff noted that license renewal drawings identify that valves FCV-417-L, FCV-417, FCV-427-L, FCV-427, FCV-437-L, FCV-437, FCV-447-L, FCV-447, BF2-21, and BF2-22 for the IP2 main FW system are within the system evaluation boundary but are not highlighted, indicating that they are not subject to an AMR. The staff asked the applicant to explain the valves' exclusion from an AMR.

In its response, dated January 4, 2008, the applicant explained that these FW system valves are located upstream of the containment isolation check valves in nonsafety-related piping but are classified as safety-related because of their active function to provide FW isolation. The applicant also stated that these valves "have no passive intended function for 54.4(a)(1) or (a)(3) because their failure would accomplish the safety function of isolating feedwater flow to the SGs." The applicant further stated that these valves perform their function with moving parts; therefore, in accordance with 10 CFR 54.21(a)(1)(i), they are not subject to an AMR and are not highlighted on the license renewal drawing. However, the applicant did indicate that the valves in question are within the scope of license renewal for meeting the requirements of 10 CFR 54.4(a)(2) because of their potential for spatial interaction with safety-related equipment and are, therefore, subject to an AMR.

The staff did not agree with the applicant's rationale that the valves do not have a passive intended function in accordance with 10 CFR 54.4(a)(1). The staff discussed the applicant's view during a telephone call on March 7, 2008. The applicant subsequently amended its RAI response by letter dated March 24, 2008, and reiterated that the FW system valves are safety-related; however, although not highlighted, the applicant stated that these valves and the remainder of the FW system components on the associated license renewal drawing are in scope and subject to an AMR based upon meeting the requirements of 10 CFR 54.4(a)(2) because of their potential for spatial interaction with safety-related equipment.

Based on its review, the staff finds the applicant's amended response to RAI 2.3B.4.2-1 acceptable because the applicant confirmed that the valves in question are within the scope of license renewal pursuant to 10 CFR 54.4(a) and subject to an AMR pursuant to 10 CFR

54.21(a)(1). Although the staff does not agree with the applicant's basis for determining how the valve bodies are subject to an AMR, the staff's concern is resolved because the AMR was performed, and the AMR results were provided in LRA Table 3.3.2-19-12-IP2. The staff's concern described in RAI 2.3A.4.2-1 is resolved.

In RAI 2.3A.4.2-2, dated December 30, 2007, the staff noted that UFSAR Section 14.1.10, Excessive Heat Removal Due To Feedwater System Malfunctions, states that accidental full opening of a feedwater control valve causes excessive feedwater flow, resulting in a transient is similar to, but less severe than, the hypothetical steamline break transient described in UFSAR Section 14.2.5. Therefore, the excessive feedwater flow failure is bounded by the steamline break analysis. In the steamline break analysis, in the event of the failure of the main feedwater control valve, the applicant takes credit the main feedwater stop valves, BFD-5's, to close within 120 seconds. In its revised response to RAI 2.3A.4.2-1, dated March 24, 2008, the applicant stated that the feedwater control valves and the remainder of the feedwater system components on the associated license renewal drawing are within scope of license renewal based upon meeting the requirements of 10 CFR 54.4(a)(2), having the potential for spatial interaction with safety-related equipment, and are subject to an AMR.

Based the applicant's UFSAR, the main feedwater stop valves (BFD-5's) have an intended function that meets the criteria of 10 CFR 54.4(a)(1); however, these valves are neither included within the "system intended function boundary," nor are they highlighted on the license renewal drawings for having a intended function in accordance with 10 CFR 54.4(a)(1). By letter dated December 30, 2008, the staff requested the applicant to justify the exclusion of the main feedwater stop valves (BFD-5's), from scope of license renewal in accordance with 10 CFR 54.4(a)(1). This issue was also identified as Open Item 2.3.4.2-1.

By letter dated January 27, 2009, the applicant stated that based upon a review of the qualifications of the main feedwater stop valves, the BFD-5s are classified as nonsafety-related. Further, the applicant explained that the valves are classified nonsafety-related in the site component database and are located outside the Class I boundary [as corrected by letter dated March 13, 2009] on license renewal drawing LRA-9321-2019-0. As indicated in the IP2 UFSAR, these valves provide a backup isolation function for feedwater in the event of such accidents as a feedwater or steamline break. Credit for nonsafety-related components as a backup to safety-related components in mitigating breaks in seismically-qualified steam line piping is consistent with regulatory guidance provided in Section 15.1.5, "Steam System Piping Failures Inside and Outside of Containment (PWR)," of the Standard Review Plan (NUREG-0800) and is also consistent with the allowance for feedwater regulating and bypass valves to be nonsafety-related, as discussed in NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum from Director, NRR to NRR Staff." The applicant concluded that, consistent with the CLB, regulatory guidance, and NUREG-0138, the BFD-5 valves are classified as nonsafety-related, and as such, meet the criteria to be included in scope for license renewal under 10 CFR 54.4(a)(2).

Based on the information provided by the applicant, the staff finds applicant's response to RAI 2.3A.4.2-2 acceptable because the BFD-5 isolation valves are nonsafety-related components, and the valves are included in the scope for license renewal under 10 CFR 54.4(a)(2). Therefore, the staff's concern described in RAI 2.3A.4.2-2 is resolved. As a result, Open Item 2.3.4.2-1 is closed.

2.3A.4.2.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and a drawing to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. The staff concludes that the applicant has appropriately identified the main FW system 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).

2.3A.4.3 IP2 Auxiliary Feedwater System

2.3A.4.3.1 Summary of Technical Information in the Application

LRA Section 2.3.4.3 describes the AFW system, which supplies adequate feedwater to the SGs to remove reactor decay heat under all circumstances, including loss of power and normal heat sink (e.g., condenser isolation or loss of CW flow), and identifies, as major components, the condensate storage tank (CST) and three AFW pumps—one steam turbine driven and two electric motor driven. Diverse AFW supplies come from two pumping systems using separate sources of motive power for their pumps. Each system supplies AFW to all four SGs. Two of the SGs can supply the steam turbine-driven pump. The AFW system operates during plant startup at low power levels before the main FW pump is available.

The CST is the safety-grade water source for the system, with a minimum water level maintained for an adequate inventory. The AFW pumps can draw an alternative supply from the city water storage tank for long-term cooling.

The AFW system contains safety-related components relied on to remain functional during and following DBEs. In addition, the AFW system performs functions that support fire protection, ATWS, and SBO.

Instrument air components included in the AFW system are reviewed with the compressed air systems (LRA Section 2.3.3.4). A small number of components are reviewed with the city water system (LRA Section 2.3.3.17).

LRA Table 2.3.4-3-IP2 identifies AFW system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.3, UFSAR Section 10.2.6.3, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.4.3, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3A.4.2-2, dated February 13, 2008, the staff noted that LRA Section 2.3.4.3 states that the AFW system has no intended function under 10 CFR 54.4(a)(2). The staff indicated that the applicant had not highlighted components adjacent to safety-related systems on license renewal drawings; these components adjacent to safety-related systems may need to be considered under 10 CFR 54.4(a)(2) because of the potential for adverse spatial interaction. For IP2, these components include piping to the AFW pump bearing cooling line and the chemical FW line to AFW. The staff requested that the applicant confirm that it had evaluated the aforementioned components for inclusion within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2).

In its response, dated March 12, 2008, the applicant stated that it assigned the bearing cooling lines to the AFW pumps identified by the staff to the city water system, and these lines are subject to an AMR based on the requirements of 10 CFR 54.4(a)(2). The applicant explained that several valves and components shown in dashed lines on one drawing indicate that they appear on the main drawing associated with that system. The applicant identified these components as part of the AFW system and as being within the scope of license renewal and subject to an AMR, in accordance with 10 CFR 54.4(a)(1). The applicant scoped the piping and components on the chemical feed line identified by the staff as part of the chemical feed system. The applicant included the chemical feed system components within the scope of license renewal under 10 CFR 54.4(a)(2), and these components are subject to an AMR.

During the review of the applicant's response to RAI 2.3A.4.2-2, the staff identified other piping lines on license renewal drawing LRA-9321-20183-001 that the applicant had not highlighted, but that were directly connected to highlighted lines. In a telephone conference held on May 30, 2008 (ADAMS Accession No. ML081720557), the staff asked the applicant to indicate whether these lines were within the scope of license renewal under 10 CFR 54.4(a)(2). The applicant explained that it had made a drawing error. The non-highlighted piping line for the AFW system, which includes valve CT-711, is within the scope of license renewal, in accordance with 10 CFR 54.4(a)(1), and should be highlighted. The applicant also explained that the non-highlighted short segments of piping coming off the highlighted valves, CT-709 and CT-710, are valve sealing water under the condensate system and are within the scope of license renewal under 10 CFR 54.4(a)(2).

Based on its review, the staff finds the applicant's response to RAI 2.3A.4.2-2 acceptable because it adequately explained that the components in question are within the scope of license renewal under 10 CFR 54.4(a)(2) because of their potential to adversely interact spatially with safety-related equipment; furthermore, these components are subject to an AMR, in accordance with 10 CFR 54.21(a)(1). The staff's concern described in RAI 2.3A.4.2-2 is resolved.

2.3A.4.3.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has appropriately identified the AFW system 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).

2.3A.4.4 IP2 Steam Generator Blowdown System

2.3A.4.4.1 Summary of Technical Information in the Application

LRA Section 2.3.4.4 describes the SGBD system, which can control the concentration of solids in the shell side of the SGs. The system, which operates normally with a continuous blowdown and sample flow, has a drain connection and two blowdown connections (nozzles) at the bottom of each SG. Pipes from the connections (nozzles) join to form a stainless steel blowdown header. Four individual blowdown headers extend from each SG to the PAB through containment isolation valves. Blowdown flows normally to the flash tank, flashed vapor discharges to the atmosphere, and the condensate drains by gravity through an SW discharge line into the CW discharge canal. The system combines, cools, and monitors the sample flows for radiation.

The SGBD system contains safety-related components relied upon to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the SGBD system performs functions that support fire protection, ATWS, and SBO.

The applicant reviewed a small number of SGBD components with the SW system in LRA Section 2.3.3.2.

LRA Tables 2.3.4-4-IP2 and 2.3.3-19-36-IP2 identify SGBD system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3A.4.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.4, UFSAR Section 10.2.1.5, and a license renewal drawing using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3A.4.4.3 Conclusion

The staff reviewed the LRA, UFSAR, and a drawing to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the SGBD system 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).

2.3A.4.5 IP2 Auxiliary Feedwater Pump Room Fire Event

2.3A.4.5.1 Summary of Technical Information in the Application

LRA Section 2.3.4.5 describes the IP2 AFW pump room fire event, which supplies and supports main FW flow to the SGs during a shutdown (IP2 only). The applicant credits this combination of systems for supplying makeup water to the SGs during a fire in the auxiliary boiler feed pump room for an assumed duration of at least 1 hour. This method was necessary because the current design and CLB assume that plant personnel cannot reenter the area for at least 1 hour following onset of a fire. A combination of secondary systems and components supplies the SGs if a fire in the AFW pump room makes it unavailable for operator actions. These plant systems and components supply FW flow through the main FW isolation valves to the SGs from the IP1 CSTs. Feedwater flows from the IP1 tanks through the hotwell dump, condensate transfer pump, condensate pumps, boiler feed pumps, and main FW isolation valves to the SGs. The following systems support this flowpath (the LRA section reference is included for those systems described elsewhere):

- auxiliary steam
- conventional closed cooling
- condensate (LRA Section 2.3.4.6)
- CW
- city water (LRA Section 2.3.3.17)
- FW (LRA Section 2.3.4.2)
- fresh water cooling (IP1 system)
- instrument air (LRA Section 2.3.3.4)
- instrument air closed cooling
- lube oil
- MS (LRA Section 2.3.4.1)
- river water service (IP1 system)
- SW (LRA Section 2.3.3.2)
- station air (IP1 system) (LRA Section 2.3.3.4)
- water treatment plant (IP1 system)
- wash water

These systems are normally in service and available prior to a fire in the auxiliary feed pump room. For those systems not described elsewhere in the LRA, a brief description is provided below.

Auxiliary Steam. The auxiliary steam system supplies steam for room and area heating, including the containment and the control room, and for various plant components, such as the RWST heating coil. The system includes IP1 and IP2 components. The heating function is not safety related. However, the system has several containment penetrations with safety-related components, and the RWST heating coil has a pressure boundary safety function. In the event of an AFW pump room fire, auxiliary steam supports the condenser water box priming steam jet air ejectors and preheats oil in the lube oil system.

Conventional Closed Cooling. The conventional closed cooling system supplies cooling water to various components, including condensate and heater drain pumps, main boiler feed pump pedestals, and station air compressors. This system has circulating pumps, heat exchangers (cooled by service water), a head tank, distribution piping valves, instruments, and controls. Cooling water from the conventional closed cooling system is not required to support any system safety function.

Circulating Water. The CW system supplies cooling water to the condenser to condense the steam exiting the low-pressure and main boiler feed pump turbines. The Hudson River supplies the condenser circulating water. The six condenser CW pumps are in the intake structure. The system pipes circulating water to the condensers and discharges it back into the river via the discharge canal. The system includes the CW pumps, condenser inlet and outlet water boxes, piping, valves, instruments, and controls.

Fresh Water Cooling. The fresh water cooling system cools miscellaneous, nonsafety-related heat loads, including IP1 air compressors and house service boiler components. The system includes the fresh water cooling recirculating tank, fresh water circulating pumps, heat exchangers cooled by river water, distribution piping, and valves. This system does not include any safety-related components.

Instrument Air Closed Cooling. The instrument air closed cooling system removes heat from the instrument air compressors and after-coolers. The system consists of a separate closed loop cooling water system of two small pumps, valves, piping, and heat exchangers that supply cooling water to the instrument air compressors and after-coolers and reject that heat to the SWS.

Lube Oil. The lube oil system, which supplies oil for lubrication and control of the main turbine and the main boiler FW pumps and turbines, includes the main lubricating/control oil reservoirs, pumps, coolers, piping, valves, indicators, and components of the main turbine controls. The applicant credits two turbine control components for turbine trip for Appendix R safe shutdown. The auto-stop trip solenoid has only an active function for turbine trip. The auto-stop oil turbine trip solenoid releases oil pressure to trip and need not maintain a pressure boundary. Neither of these components has a passive mechanical intended function.

River Water Service. The river water service system supplies cooling water from the Hudson River to the fresh water cooling system heat exchangers. This system consists primarily of IP1 equipment used to support IP2. The system provides backup to the SW system by providing nonessential loads. It includes four Class A pipe segments that support the SW system. The pipe segments are part of the SW supply and return from the instrument air cooling water heat exchanger.

Water Treatment Plant. The water treatment plant system supplies water for various uses throughout the plant. The water treatment plant consists primarily of IP1 equipment in the superheater building. The system, which takes city water through demineralization for all three units, includes demineralization and deaeration equipment, distribution piping, valves, instruments, controls, and the IP1 CSTs. In the event of an AFW pump room fire, the IP1 CSTs provide make-up water to the SGs. The make-up water flows from the IP1 CSTs to the IP2 hotwell dump and condensate transfer pump.

Wash Water. The wash water system washes fish and debris from the traveling screens for return to the river. The system includes the pumps, piping, strainers, valves, instruments, and controls for the screen wash function. Wash water components are not required to support SW system operation.

The IP2 AFW pump room fire event systems contain safety-related components relied on to remain functional during and following DBEs. They also contain nonsafety-related components whose failure could prevent the satisfactory accomplishment of a safety-related function. In addition, the IP2 AFW pump room fire event systems perform functions that support fire protection.

The IP2 AFW pump room fire event systems contain components that are evaluated with other systems. Auxiliary steam system components supporting the RWST pressure boundary are evaluated with the safety injection systems (LRA Section 2.3.2.4). River water system components supporting the SW system pressure boundary are evaluated with the SW system (LRA Section 2.3.3.2). Containment penetrations are evaluated with other containment penetrations (LRA Section 2.3.2.5).

Nonsafety-related components not evaluated with other systems whose failure could prevent satisfactory accomplishment of safety-related functions are evaluated with miscellaneous systems that are in scope under 10 CFR 54.4(a)(2) (LRA Section 2.3.3.19). For these systems, the following LRA tables identify IP2 AFW pump room fire event component types within the scope of license renewal under 10 CFR 54.4(a)(2), as well as their intended functions:

- LRA Table 2.3.3-19-1-IP2
- LRA Table 2.3.3-19-2-IP2
- LRA Table 2.3.3-19-6-IP2
- LRA Table 2.3.3-19-13-IP2
- LRA Table 2.3.3-19-19-IP2
- LRA Table 2.3.3-19-22-IP2
- LRA Table 2.3.3-19-32-IP2
- LRA Table 2.3.3-19-43-IP2

The staff notes that the LRA does not identify 10 CFR 54.4(a)(2) components of the wash water system. The applicant stated that it performed a review of the liquid-filled components that were not included in other AMRs and determined that the wash water system components are located where they cannot affect equipment with safety-related functions.

The intended function of the IP2 AFW pump room fire event component types within the scope of license renewal is primarily to provide pressure boundary integrity for adequate flow and pressure delivery. For license renewal, the primary intended function of AFW pump room fire event components is to maintain system pressure boundary integrity. Some components retain other functions (e.g., the heat exchangers have the function of heat transfer, and the filters provide filtration).

Aging management of the systems required to supply feedwater to the SGs during an AFW pump room fire is not based on the analysis of materials, environments, and aging effects. System components required to supply feedwater to the SGs during the short duration of such a fire are in service or available when the event occurs. Required components are separated from the AFW pump room; therefore, normal plant operation continuously confirms the integrity of the systems and components required for post-fire intended functions for at least 1 hour.

During the event, these systems and components must continue to perform their intended functions by supplying feedwater to the SGs for the 1-hour minimum duration assumed by the applicant. Significant degradation that could threaten the performance of intended functions will be apparent in the period immediately preceding the event, and corrective action will be required to sustain continued operation. For the minimal 1-hour period that these systems are required to supply make-up water to the SGs, further aging degradation apparent before the event is negligible; therefore, the applicant's evaluation considered no aging effects.

The IP1 CSTs are subject only to intermittent service; therefore, a daily check of tank level and intermittent usage of piping and valves from the IP1 CSTs to the IP2 condenser confirm availability. Significant degradation that could threaten the performance of the intended functions will be apparent in the period immediately preceding the event, and corrective action will be required to sustain continued operation.

Normal plant operation ensures adequate pressure boundary integrity, as well as the post-fire intended function to supply feedwater to the SGs; therefore, no specific AMP is required.

The intended function of the IP2 AFW pump room fire event component types within the scope of license renewal is to provide pressure boundary integrity for adequate flow and pressure delivery.

2.3A.4.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.5 and the UFSAR using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.4.5, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3A.4.5-1, dated December 7, 2007, the staff noted that, in LRA Section 2.3.4.5, the applicant stated that water treatment plant components are credited for the AFW pump fire event to support safe shutdown in the event of a fire in the IP2 AFW pump room. The applicant indicated that water from the IP1 CSTs is used as makeup water for the IP2 SGs. The applicant further described a combination of IP1 and IP2 systems that are used to complete this flowpath. The applicant stated that the current design and licensing bases requires this flowpath to be available for at least 1 hour following onset of the fire because the applicant assumes that personnel are unable to re-enter the area for at least 1 hour. The staff noted that, although the LRA states that the IP1 components comprising the required flowpath have an intended function under 10 CFR 54.4(a)(3) to support safe shutdown in a fire event, license renewal drawings do not identify the flowpath or its components.

The staff asked to applicant to identify those long-lived components comprising the required flowpath and to indicate whether they are subject to an AMR, in accordance with

10 CFR 54.21(a).

In its response, dated January 4, 2008, the applicant stated that it verifies the levels in the IP1 CSTs on a daily basis. The applicant also indicated that the majority of the components in this flowpath, as part of the water treatment plant system, are included within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2), and are subject to an AMR. Finally, the applicant agreed that a few outdoor components (e.g., tanks, piping and valves) are not included in LRA Section 2.3.4.5. The applicant amended the LRA to include the components to provide further assurance that their intended functions can be performed. The applicant revised LRA Table 3.3.2-19-43-IP2 to add the line items that were not previously included (i.e., carbon steel for the IP1 CSTs).

Based on its review, the staff finds the response to RAI 2.3A.4.5-1 acceptable because the applicant adequately explained that the majority of the components in this flowpath are included within the scope of license renewal as part of the water treatment plant system. The applicant added the few outdoor components that had not been included in this LRA section as within the scope of license renewal and subject to an AMR. For these components, the staff's concern described in RAI 2.3A.4.5-1 is resolved. SER Sections 3.3.2.1 and 3.3A.2.3.33 document the staff's evaluation of new AMR results for the carbon steel CSTs.

In LRA Section 2.3.4.5, the applicant described systems not discussed elsewhere in the LRA that are credited for mitigating the consequences of an IP2 fire event in the AFW pump room. The intended function of each system listed is to support safe shutdown in the event of a fire in the auxiliary feed pump room (10 CFR 50.48), in accordance with 10 CFR 54.4(a)(3). The applicant stated that "no License renewal drawings are provided based on the intended function of supporting safe shutdown in the event of a fire in the auxiliary feed pump room." However, the applicant stated in LRA Section 2.2 that "[c]omponents subject to aging management review are highlighted on license renewal drawings, with the exception of components in scope for 10 CFR 54.4(a)(2)." Since the SCs that support mitigating the consequences of a fire event are in scope under 10 CFR 54.4(a)(3) and are subject to an AMR, in accordance with 10 CFR 54.21(a)(1), the applicant should have highlighted the components on the license renewal drawings. However, the applicant did not highlight the components or flowpaths needed to support this event. In addition, the applicant did not, in accordance with 10 CFR 54.21(a)(1), identify and list the SCs that are subject to an AMR. Therefore, based on the information provided in the LRA, the staff was unable to verify those components that are included within the scope of license renewal to perform the stated function and are subject to an AMR.

In RAI 2.3A.4.5-2, dated December 30, 2008, the staff asked the applicant to (a) identify the system support function for the AFW pump room fire event for each system that supports the flowpath, (b) clearly identify the portion of the systems' flowpaths that support these functions and are subject to an AMR, and (c) identify the portion of these flowpaths that are not already in scope under 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(2). This issue was identified as Open Item 2.3.4.5-1.

By letter dated January 27, 2009, the applicant explained that its mitigating strategy in the event of a fire in the AFW pump room is to use equipment that the plant typically uses during normal operation. The applicant assumed that if the equipment is available for normal operations, then it would be available in the event of a fire in the AFW pump room. In its response, the applicant identified those systems and their functions that it credits for use in an AFW pump room fire event.

The applicant amended LRA Section 2.2 to explain that it did not highlight those components required for the AFW pump room fire event, as described in Section 2.3.4.5, on license renewal drawings. The applicant described, for each system required to mitigate the AFW pump room fire event, the system's safety functions and the component types, along with their respective intended function. In addition, the applicant identified any components of these systems that it had not previously identified as within the scope of license renewal under 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(2).

Among those systems required for the AFW pump room fire event, the applicant identified four IP1 systems that it credited as continuously in service during normal plant operation: river water, station air, water treatment plant, and fresh water cooling. The normal condensate flowpath from the IP2 CST may be lost during a fire in the AFW pump room; therefore, the applicant credited the use of the IP1 CSTs, which are not typically in service. As described in its response to RAI 2.3A.4.5-1, the applicant added those components in the flowpath from the IP1 CSTs to the scope of license renewal, in accordance with 10 CFR 54.4(a)(3), that were not already included in the scope for license renewal under 10 CFR 54.4(a)(2). The other three IP1 systems supplement the respective IP2 systems and typically operate to support the normal operations of IP2.

Based on its review, the staff finds the applicant's response to RAI 2.3A.4.5-2 acceptable because it included the components required to support the safety function in the event of a fire in the AFW pump room within scope, in accordance with 10 CFR 54.4(a)(3), and identified passive long-lived components requiring an AMR, in accordance with 10 CFR 54.21. Therefore, the staff's concern described in RAI 2.3A.4.5-2 is resolved. (The staff evaluated the adequacy of the AMR performed for these components in its review of the applicant's response to RAI 3.4.2-1. SER Section 3.4.2 includes the results of this evaluation.)

2.3A.4.5.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI responses to determine whether the applicant failed to identify any SSCs within the scope of license renewal or failed to identify any components subject to an AMR. As described above, the applicant satisfactorily resolved the omission of components from an AMR. The staff found no further omissions. On the basis of its review, the staff concludes that the applicant has appropriately identified the IP2 AFW pump room fire event system 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).

2.3A.4.6 IP2 Condensate System

2.3A.4.6.1 Summary of Technical Information in the Application

LRA Section 2.3.4.6 describes the condensate system, which transfers condensate and low-pressure heater drainage from the condenser hotwell through five stages of FW heating to the main FW pumps. Three condensate pumps, arranged in parallel, take suction from the bottom of the condenser hotwells and discharge into a common header that carries a portion of the condensate through three steam jet air ejector condensers arranged in parallel and one gland steam condenser. The condensate passes through the tube sides of three parallel strings of two low-pressure FW heaters. The flows from these heaters combine in a common line which divides to go to the remaining three strings of three low-pressure heaters. After the No.5 FW heater, the three condensate lines join into a common header. The heater drain pump discharge enters this header and continues on to the suction of the main FW pumps.

The condensate system includes most components from the condenser to the outlet of the main boiler FW pumps, the main condensers, the condensate and main boiler FW pumps, low-pressure FW heaters, piping, valves, instruments, and controls. Most of the system is not safety related; however, the air ejector discharge to containment penetration is in this system code.

Some system components support the pressure boundary of the AFW system flowpath from the CST to the AFW pumps.

The condensate system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function.

Condensate system components that support safe shutdown in the event of an auxiliary feed pump room fire are evaluated in LRA Section 2.3.4.5. Components that support the AFW system flowpath pressure boundary are reviewed with the AFW systems (LRA Section 2.3.4.3). Containment penetration components are reviewed with containment penetrations (LRA Section 2.3.2.5).

2.3A.4.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.6 and UFSAR Section 10.2.6 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3A.4.6.3 Conclusion

The staff reviewed the LRA, UFSAR, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant had adequately identified the condensate system 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).

2.3B IP3 Scoping and Screening Results: Mechanical Systems

2.3B.1 Reactor Coolant System

LRA Section 2.3.1 identifies the RCS SCs subject to an AMR for license renewal.

The RCS includes mechanical components in the following subsystems:

- reactor vessel
- reactor vessel internals
- SGs
- RCPs
- pressurizer
- control rod drives
- in-core instrumentation
- reactor vessel level instrumentation
- SG secondary-side instrumentation
- SG level control

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

- 2.3.1.1, "Reactor Vessel"
- 2.3.1.2, "Reactor Vessel Internals"
- 2.3.1.3, "Reactor Coolant Pressure Boundary"
- 2.3.1.4, "Steam Generators"

LRA Section 2.3.1 describes the following RCS subsystems:

Reactor Vessel. The cylindrical reactor vessel has a hemispherical bottom and a flanged and gasketed removable upper head. The upper reactor closure head and the reactor vessel flange are joined by studs. Two metallic O-rings seal the reactor vessel when the reactor closure head is bolted in place. A leak-off connection between the two O-rings monitors leakage across the inner O-ring. Vessel design was in accordance with ASME Code, Section III. Coolant enters the reactor vessel through inlet nozzles in a plane just below the vessel flange and above the core, flows downward through the annular space between the vessel wall and the core barrel into a plenum at the bottom of the vessel, reverses direction, and flows up through the core. After mixing in the upper plenum, the mixed coolant stream then flows out of the vessel through exit nozzles on the same plane as the inlet nozzles. The core instrumentation nozzles are on the lower head, and the control rod nozzle penetrations are on the upper head.

Reactor Vessel Internals. The reactor vessel internals direct the coolant flow, support the reactor core, and guide the control rods. The reactor vessel contains the core support assembly, upper plenum assembly, fuel assemblies, control cluster assemblies, surveillance specimens, and in-core instrumentation. The reactor vessel internals consist of three major parts: the lower core support structure, the upper core support structure, and the in-core instrumentation support structure. A one-piece thermal shield, concentric with the reactor core, is between the core barrel and the reactor vessel. The shield, cooled by the coolant on its downward pass, protects the vessel by attenuating much of the gamma radiation and some of the fast neutrons that escape from the core.

Steam Generators. Each loop has a vertical shell and a U-tube SG. Reactor coolant enters the inlet side of the channel head at the bottom of the SG through the inlet nozzle, flows through the U-tubes to an outlet channel, and exits the generator through another bottom nozzle. The inlet and outlet channels are separated by a partition. Feedwater to the SG enters just above the top of the U-tubes through an FW ring, flows downward through an annulus between the tube wrapper and the shell, and then flows upward through the tube bundle where it converts to a steam-water mixture that passes through a primary separator assembly that reduces the water content in the mixture. The separated water combines with the feedwater for another pass through the tube bundle. The remaining higher steam content mixture rises through additional secondary separators to further reduce its water content.

Reactor Coolant Pumps. Each reactor coolant loop has a vertical, single-stage centrifugal pump with a controlled leakage seal assembly. Reactor coolant pumped by the impeller attached to the bottom of the rotor shaft and drawn up through the impeller discharges through passages in the diffuser and out through a discharge nozzle in the side of the casing. A flywheel at the top of the rotor shaft extends the pump coastdown flow during any loss of power to the pump motor. A portion of the flow from the CVCS charging pumps is injected into the RCP between the impeller and the controlled leakage seal. CCW flows to the motor bearing oil coolers and the thermal barrier cooling coil.

The RCS contains safety-related components relied on to remain functional during and following DBEs. The failure of nonsafety-related SSCs in the RCS could prevent the satisfactory accomplishment of a safety-related function. In addition, the RCS performs functions that support fire protection, PTS, ATWS, and SBO.

Pressurizer. The pressurizer system maintains the required reactor coolant pressure during steady-state operation, limits the pressure changes of coolant thermal expansion and contraction during normal load transients, and prevents RCS pressure from exceeding design pressure. The pressurizer maintains pressure by electrical heaters and sprays. Steam can be formed by the heaters or condensed by a pressurizer spray to minimize pressure variations due to coolant contraction and expansion. The pressurizer design accommodates inflow and outflow surges caused by load transients. The surge line attached to the bottom of the pressurizer connects it to the hot leg of a reactor coolant loop. The pressurizer protects the RCS from overpressure by code relief valves connected to its top head. Two PORVs and three code safety valves protect against pressure surges beyond the pressure-limiting capacity of the pressurizer spray. The PORV also operates from the overpressure protection system to prevent RCS pressure from exceeding the limits found in ASME Code, Section III, Appendix G, during low-temperature operation. Steam and water discharge from the power relief and safety valves passes to the pressurizer relief tank partially filled with water at or near ambient containment conditions. The tank normally contains water in a predominantly nitrogen atmosphere. Steam discharged under the water level condenses and cools by mixing with the water. Rupture discs that discharge into the reactor containment protect the tank against a discharge exceeding the design value. The system includes the pressurizer, pressurizer relief valves, PORVs, spray line components, pressurizer relief tank, piping, valves, instruments, controls, and several containment penetrations supporting the pressurizer relief tank.

The pressurizer system contains safety-related components relied on to remain functional during and following DBEs. The failure of nonsafety-related SSCs in the pressurizer system could prevent the satisfactory accomplishment of a safety-related function. In addition, the pressurizer system performs functions that support fire protection and SBO.

Control Rod Drives. The control rod drive system positions the control rods within the core. The reactor uses the Westinghouse magnetic-type control rod drive assemblies on the upper reactor vessel head to insert or withdraw the rods to control generation of nuclear power. Control rod motion is accomplished through the sequential operation of three different magnetic coils. Upon a loss of power to the coils, the released rod cluster control assemblies with full-length absorber rods fall by gravity into the core. Each control rod drive assembly is designed as a hermetically-sealed unit to prevent leakage of reactor coolant. The design of all pressure-containing components meets the requirements of ASME Code, Section III, Division 1, for Class A vessels.

The control rod drive system contains safety-related components relied on to remain functional during and following DBEs.

In-Core Instrumentation. The in-core instrumentation system provides information on the neutron flux distribution and fuel assembly outlet temperatures at selected core locations to confirm the reactor core design parameters and calculated hot channel factors. The system acquires data and performs no operational plant control. The system consists of thermocouples positioned to measure fuel assembly coolant outlet temperature at preselected locations, flux thimbles running the length of selected fuel assemblies to measure the neutron flux distribution within the reactor core using moveable in-core detectors, and in-core drives, drive motors, positioning equipment, and instruments. The flux thimbles, seal table, and guide tube form part of the RCPB.

The in-core instrumentation system contains safety-related components relied on to remain functional during and following DBEs.

Reactor Vessel Level Instrumentation. The reactor vessel level instrumentation monitors the water level in the reactor vessel or relative voids in the RCS during accident conditions. The instrumentation indicates levels from the bottom of the reactor vessel to the top of the reactor head during natural circulation conditions and indicates reactor vessel liquid level for any combination of running RCPs. The instrumentation utilizes RCS penetrations leading to manual isolation valves at which sealed capillary impulse lines transmit pressure measurements to transmitters outside the containment building. Sensor bellows serving as hydraulic couplers seal the capillary impulse lines at the RCS end and at the penetrations. The impulse lines extend through the containment wall to hydraulic isolators which seal and isolate the lines and hydraulically couple them to capillary tubes going to the transmitters.

The reactor vessel level instrumentation system (RVLIS) contains safety-related components relied on to remain functional during and following DBEs. The failure of nonsafety-related SSCs in the RVLIS could prevent the satisfactory accomplishment of a safety-related function.

Steam Generator (Secondary-Side Instrumentation). The SG system has secondary-side instrumentation. The SG system code includes the passive mechanical instrument piping and valves for the SG secondary-side-level instrumentation. These components are safety related because they form part of the SG pressure boundary.

The SG system contains safety-related components relied on to remain functional during and following DBEs. In addition, the SG system performs functions that support fire protection and SBO.

Steam Generator Level Control. The SG level control system supports the control of FW flow to maintain SG secondary-side level. Primarily an electrical system, it includes several level instrument vent valves. These components are safety related because they form part of the SG pressure boundary.

The SG level control system contains safety-related components relied on to remain functional during and following DBEs. In addition, the SG level control system performs functions that support fire protection and SBO.

The RCS Class I piping evaluation boundary extends into portions of systems attached to the RCS. For both units, the RCS AMR includes the Class I components of the systems listed below. The applicant evaluated the non-Class 1 system portions in the LRA section indicated:

- CVCS (LRA Section 2.3.3.6)
- isolation valve seal water (LRA Section 2.3.2.3)
- primary sampling (LRA Section 2.3.3.19)
- RHR system (LRA Section 2.3.2.1)
- safety injection system (LRA Section 2.3.2.4)

IP3 RCS RCP lube oil collection system components are reviewed with the fire protection—CO_2, Halon, and RCP oil collection systems (LRA Section 2.3.3.12).

Components in the IP3 nitrogen supply to the PORVs are reviewed with the nitrogen systems (LRA Section 2.3.3.5). A small number of IP3 pressurizer components are reviewed with the primary water makeup systems (LRA Section 2.3.3.7).

The following components are evaluated with containment penetrations (LRA Section 2.3.2.5):

- IP3 pressurizer system containment penetration components
- certain mechanical IP3 RVLIS components

Fuel assemblies replaced after a limited number of fuel cycles are not subject to an AMR. The control rods are active components and, therefore, are not subject to an AMR.

The intended function of the RCS component types within the scope of license renewal is to provide pressure boundary integrity for adequate flow and pressure delivery.

Because the IP2 and IP3 RCS and supporting SCs are very similar, SER Sections 2.3A.1.1–2.3A.1.4, respectively, document the staff's review findings for LRA Sections 2.3.1.1–2.3.1.4 for IP3.

2.3B.2 Engineered Safety Features

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

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

- 2.3.2.1, “Residual Heat Removal”
- 2.3.2.2, “Containment Spray System”
- 2.3.2.3, “Containment Isolation Support Systems”
- 2.3.2.4, “Safety Injection Systems”
- 2.3.2.5, “Containment Penetrations”

The staff summarized the findings of its review of LRA Sections 2.3.2.1–2.3.2.5 in SER Sections 2.3B.2.1–2.3B.2.5, respectively.

2.3B.2.1 IP3 Residual Heat Removal

2.3B.2.1.1 Summary of Technical Information in the Application

LRA Section 2.3.2.1 describes the RHR system, which provides emergency core cooling as part of the safety injection system and removes residual heat during later stages of plant cooldown. The RHR system is one of three (RHR, CCW, SFPC) auxiliary coolant systems. The RHR system consists of two RHR heat exchangers, two seal coolers, two RHR (low-head) pumps, and required piping, valves, and I&C components. The RHR system provides emergency core cooling during the injection phase of a LOCA. The RHR heat exchangers, in conjunction with the safety injection recirculation pumps, provide post-accident heat removal during the LOCA recirculation phase. Outlet flow from the RHR heat exchangers may be directed to the CS headers, to the RCS cold legs, or to the RCS hot legs via the high-head safety injection pumps. The RHR pumps also back up the safety injection system recirculation pumps during the LOCA recirculation phase. In this capacity, the RHR pumps may draw water from the containment sump and deliver it to the RCS cold leg injection lines, to the suction of the high-head safety injection pumps, or to the CS headers. The RHR system removes residual heat during later stages of plant cooldown, as well as during cold shutdown and refueling operations. After the RCS temperature and pressure have been reduced to 350 degrees F and less than 450 psig, alignment of the RHR pumps initiates decay heat cooling by taking suction from one reactor hot leg and discharging it through the RHR heat exchangers into the reactor cold legs.

The RHR system contains safety-related components relied on to remain functional during and following DBEs. In addition, the RHR system performs functions that support fire protection and SBO.

In the LRA, ASME Code Class 1 components with the intended function of RCPB maintenance are reviewed with the RCS (LRA Section 2.3.1). A small number of components are reviewed with the CCW system (LRA Section 2.3.3.3).

LRA Table 2.3.2-1-IP3 identifies RHR system component types within the scope of license renewal and subject to an AMR as well as their intended functions.

2.3B.2.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.1, the UFSAR, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3B.2.1.3 Conclusion

The staff reviewed the LRA, UFSAR, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the RHR system 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).

2.3B.2.2 IP3 Containment Spray System

2.3B.2.2.1 Summary of Technical Information in the Application

LRA Section 2.3.2.2 describes the CS system, which cools the containment and removes iodine following an accident. The system consists of two trains of pumps, valves, and spray headers that spray borated water into the containment automatically when the system senses high containment pressure following a LOCA or MS line break accident. The CS system sprays a portion of the RWST contents into the containment atmosphere through nozzles connected to four ring headers in the containment dome. Each spray pump supplies two ring headers. The CS pumps take their suction from the RWST. After injection from the RWST has been terminated, the spray headers can be supplied with recirculated water from the recirculation sump or the containment sump by a diversion of a portion of the injection flow from the safety injection system. By letter dated June 30, 2009, the applicant submitted Amendment 8, Revision 1 to the LRA to reflect a modification to the containment spray system. The applicant stated that the buffer chemical in the containment spray system was changed from sodium hydroxide (liquid injection) to sump baskets containing sodium tetraborate. Retention of iodine during long-term post-accident conditions is assured by the sodium tetraborate baskets located in the containment that will be flooded under accident conditions, allowing the sodium tetraborate to dissolve into the fluid for pH control. The containment spray system also includes a dousing system for the carbon filter bank of each fan cooler unit of the containment air recirculation cooling and filtration system. Each dousing system can be started manually if high-temperature conditions occur.

The CS system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the CS system performs functions that support fire protection.

Containment spray system components that support the RHR system pressure boundary are reviewed with the RHR system (LRA Section 2.3.2.1). A small number of components are reviewed with the safety injection system (LRA Section 2.3.2.4).

LRA Tables 2.3.2-2-IP3 and 2.3.3-19-10-IP3 identify CS system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.2.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.2, UFSAR Section 6.3, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. In addition, the staff reviewed the applicant's letter dated June 30, 2009, which provided a modification to LRA Section 2.3.2.2 to reflect a change in the buffer chemical and the method of adding it to the containment spray system for pH control.

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

2.3B.2.2.3 Conclusion

The staff reviewed the LRA, UFSAR and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the CS system 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).

2.3B.2.3 IP3 Containment Isolation Support Systems

2.3B.2.3.1 Summary of Technical Information in the Application

LRA Section 2.3.2.3 describes the containment isolation support systems, which include the isolation valve seal water systems and the weld channel and containment penetration pressurization systems. For IP3, this evaluation also includes the PAB system, which has a containment penetration. The containment isolation support systems consist of piping and valves routed to the various system piping that penetrates the containment. The isolation valve seal water, weld channel, and containment penetration pressurization systems isolate the containment from the outside environment for various systems with piping penetrating containment. The containment isolation support systems inject fluid or either air or gas into system lines between the containment isolation valves penetrating the containment to ensure pressure boundary integrity against leakage of radioactive fluids to the environment in the event of a LOCA. These barriers of piping and isolation valves systems are defined by individual lines. Besides satisfying containment isolation criteria, the valving facilitates normal operation and maintenance of the systems for reliable operation of other engineered safeguard systems.

The isolation valve seal water system provides sealing water or gas between the isolation and double-disk isolation valves of containment penetrations located in lines connected to the RCS or exposed to the containment atmosphere during any condition which requires containment isolation. This system limits fission product release from the containment. Although not credited in post-accident dose analyses, the system ensures a containment leak rate in an accident that is lower than that assumed in the accident analysis and the offsite dose calculations. System components form parts of the containment penetration isolation boundary.

The weld channel and containment penetration pressurization systems provide pressurized gas to all containment penetrations and most liner inner weld seams so that, in a LOCA, no leakage occurs through these potential paths from the containment to the atmosphere. The system also serves spaces between selected isolation valves. Although not credited in the post-accident dose analyses, weld channel and penetration pressurization systems maintained at some pressure level above the peak accident pressure will keep any postulated leakage in, rather than out of, the containment. The plant's compressed air systems supply regulated clean, dry compressed air outside the containment to all containment penetrations and most inner liner weld channels. The primary source of air for this system is the instrument air system backed up by the station air system and by a bank of nitrogen cylinders as a standby source of gas pressure.

The PAB houses and protects emergency safeguards equipment and other systems supporting safe reactor operation. This system code is primarily structural but, because it also includes the guard pipe and enclosure containment leakage boundary for a containment sump penetration, the system has a mechanical intended function which is discussed in this section. This enclosure (tank) is a second leakage boundary for the primary containment penetration from the containment sump.

The containment isolation support systems contain safety-related components relied on to remain functional during and following DBEs. They also contain nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function.

The isolation valve seal water system components with the intended function of maintaining the RCPB are reviewed with the RCS (LRA Section 2.3.1.3).

LRA Tables 2.3.2-3-IP3 and 2.3.3-19-62-IP3 identify containment isolation support systems component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.2.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.3; UFSAR Sections 6.2.2, 6.5, and 6.6; and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.2.3, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3B.2.3-1, dated November 9, 2007, the staff identified line-mounted components (valves PCV 1076 and PCV 1090) located on sensing lines that have a pressure boundary function. However, the applicant did not identify the sensing lines (i.e., those connecting these components to the main line) as being subject to an AMR. Therefore, the staff requested that the applicant clarify whether these sensing lines are subject to an AMR.

In its response, dated December 6, 2007, the applicant stated that the sensing lines are internal to the valve bodies and provide a control function for operation of the valves. The valves (with internal sensing lines) are subject to an AMR and are identified in LRA Table 2.3.2-3-1P3 as component type "valve body," with AMR results summarized in LRA Table 3.2.2-3-1P3.

Based on its review, the staff found the applicant's response to RAI 2.3B.2.3-1 acceptable because the applicant clarified that the subject sensing lines are within the scope of license renewal and subject to an AMR. The staff's concern described in RAI 2.3B.2.3-1 is resolved.

In RAI 2.3B.2.3-2, dated November 9, 2007, the staff identified several line-mounted components (valves PCV 1193 through PCV 1199) located in lines (i.e., 3/8-inch stainless steel tubing) with a pressure boundary function. However, the applicant did not identify the components themselves as being subject to an AMR. Therefore, the staff requested that the applicant clarify whether these components are subject to an AMR or justify their exclusion.

In its response, dated December 6, 2007, the applicant stated that the line-mounted components are aluminum pressure-regulating valves. These components are within the scope of license renewal and subject to an AMR. The applicant amended the application to add the line item "valve body" to LRA Table 3.2.2-3-IP3 to reflect the aluminum material.

Based on its review, the staff finds the applicant's response to RAI 2.3B.2.3-2 acceptable because the applicant clarified that the subject valves are within the scope of license renewal and subject to an AMR. In addition, the applicant added aluminum valve bodies to the AMR. The staff's concern described in RAI 2.3B.2.3-2 is resolved. SER Section 3.2.2.1 discusses the staff's evaluation of the added AMR for aluminum valve bodies.

2.3B.2.3.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found an instance in which the applicant omitted components that should have been subject to an AMR. The applicant has satisfactorily resolved this issue as discussed in the preceding staff evaluation. On the basis of its review, the staff concludes that the applicant has adequately identified the containment isolation support 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).

2.3B.2.4 IP3 Safety Injection System

2.3B.2.4.1 Summary of Technical Information in the Application

LRA Section 2.3.2.4 describes the safety injection system, which automatically delivers cooling water to the reactor core in a LOCA to limit the fuel clad temperature so that the core remains intact and in place with its essential heat transfer geometry preserved. Components comprising the safety injection system code include the RWST, the three safety injection (high-head) pumps, the accumulators (one for each reactor loop), recirculation pumps and piping, valves, and other components of these subsystems. The three safety injection (high-head) pumps inject RWST borated water into the RCS for core cooling. The safety injection signal automatically opens the required safety injection system isolation valves and starts the safety injection pumps. The accumulators containing borated water pressurized with nitrogen are connected to the RCS by injection piping and valves. Two check valves isolate these tanks from the RCS during normal operation. When RCS pressure falls below accumulator pressure the check valves open, discharging the contents of the tanks into the RCS through the same injection piping used by the safety injection pumps.

After the injection, the recirculation system cools and returns the coolant spilled from the break and water collected from the CS to the RCS. The system recirculation pumps take suction from the recirculation sump in the containment floor and deliver spilled reactor coolant and borated refueling water back to the core through the RHR heat exchangers. For smaller RCS breaks in which recirculated water must be injected against higher pressures for long-term cooling, the system delivers the water from an RHR heat exchanger to the high-head safety injection pump suction and, by this external recirculation route, to the reactor coolant loops. The system also allows either of the RHR pumps to take over the recirculation function.

For IP3, the engineered safeguards initiation logic system was evaluated with the safety injection system. The system actuates (depending on the severity of the condition) the safety injection, containment isolation, containment air recirculation, and CS systems. The engineered safeguards initiation logic system is primarily electrical, but does include some mechanical components, specifically the piping and valves from the containment to the containment pressure transmitters, and has mechanical intended functions.

The safety injection system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the safety injection system performs functions that support fire protection.

ASME Code Class 1 components with the intended function of maintaining the RCPB are reviewed with the RCS (LRA Section 2.3.1.3). A small number of components are reviewed with the CS system (LRA Section 2.3.2.2), RHR systems (LRA Section 2.3.2.1), or nitrogen systems (LRA Section 2.3.3.5).

LRA Tables 2.3.2-4-IP3 and 2.3.3-19-53-IP3 identify safety injection system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.2.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.4, the UFSAR, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3B.2.4.3 Conclusion

The staff reviewed the LRA, UFSAR, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the safety injection system 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).

2.3B.2.5 IP3 Containment Penetrations

2.3B.2.5.1 Summary of Technical Information in the Application

LRA Section 2.3.2.5 describes the containment penetrations, which is not an independent system but a grouping of containment penetration components not evaluated with other systems. These penetrations include the following:

- electrical penetrations
- fuel core component handling system
- hydrogen recombiners
- BVS
- fuel handling
- integrated leak rate testing

The BVS system draws samples from the building ventilation to identify radioactive gases that may be present and verifies whether plant radioactive gaseous effluents are within technical specification limits. The system has several containment penetrations and a flowpath to two process radiation monitors.

The fuel-handling system defuels and refuels the reactor core and is designed to transport and handle fuel safely and effectively. The structural evaluations address most components shown in the database and the fuel storage racks and pools. The fuel transfer tube blind flange in this system code is a passive mechanical component for that containment penetration.

The integrated leak rate testing system, which tests containment integrated leak rates during shutdown conditions, has piping, valves, and equipment to pressurize containment, instrumentation to monitor containment parameters during the test, and containment penetrations isolated by blind flanges during normal operation.

The containment penetrations contain safety-related components relied on to remain functional during and following DBEs.

Components in the containment penetrations evaluated in this section are those that maintain the system pressure boundary inside containment from the first weld from the penetration to the class boundary change outside containment. Components in the Class 1 boundary are evaluated with the RCPB (LRA Section 2.3.1.3). Structural portions of the containment penetrations are evaluated with the containment building (LRA Section 2.4.1). Electrical portions of electrical penetration assemblies are evaluated with electrical components (LRA Section 2.5). Containment penetrations not included in other systems' AMRs are evaluated in LRA Section 2.3.2.5. This evaluation includes the BVS system process flowpath to the radiation monitors.

LRA Table 2.3.2-5-IP3 and newly created Table 2.3.3-19-63-IP3 (see evaluation below) identify containment penetration component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.2.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.5; UFSAR Sections 1.2.2, 5.1.4, 9.4.2, 9.5, and 11.2; and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.2.5, the staff identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

In RAI 2.3A.2.2-1, dated February 13, 2008, during review of license renewal drawings for the CS system, the staff identified portions of piping in the CS system that were not highlighted, indicating that a particular section of piping had no intended functions, in accordance with 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3). LRA Section 2.3.2.2 states that the CS system has no intended function under 10 CFR 54.4(a)(2). This section of piping is directly connected to safety-related CS piping; therefore, the staff believed that it should be in scope, in accordance with 10 CFR 54.4(a)(2), as nonsafety-related piping that is structurally attached to safety-related piping. The staff asked the applicant to explain this apparent discrepancy. The staff also asked the applicant to indicate any portions of the CS system that it evaluated for inclusion in the scope of license renewal, in accordance with 10 CFR 54.4(a)(2), and to identify any other instances in which it identified a system as not having any 10 CFR 54.4(a)(2) components, but having nonsafety-related components that were not identified as within scope under 10 CFR 54.4(a)(2).

In its response, dated March 12, 2008, the applicant determined that the components identified by the staff do have an intended function to maintain integrity such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function. The applicant responded to the staff's request by performing a reevaluation of those safety-related systems that the LRA identified as only being in scope under 10 CFR 54.4(a)(1) and that have no 10 CFR 54.4(a)(2) components. The applicant explained that it should have included the IP3 BVS system within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2).

For the BVS system, the applicant amended the LRA to reflect the changes described below:

a) LRA Table 2.3.3-19-A-IP3 would reflect the BVS system as a miscellaneous system within the scope of license renewal for 10 CFR 54.4(a)(2).

b) Removal of the BVS system from the LRA Section 2.3.3.19 table of areas excluded from an AMR based on their lack of potential for spatial interaction.

c) Revision of LRA Table 2.3.3-19-B-IP3 to reflect that the BVS system has components subject to an AMR for meeting 10 CFR 54.4(a)(2).

d) Creation of a new LRA Table 2.3.3-19-63-IP3 for the four added component types in the BVS system for nonsafety-related components potentially affecting safety function subject to AMR.

e) Creation of a new LRA Table 3.3.2-19-63-IP3 for the four added component types, their materials, environments, and AMPs.

Based on its review, the staff finds the applicant's response to RAI 2.3A.2.2-1 for the BVS system acceptable because it adequately explained that the applicant's reevaluation of safety-related systems identified components that should have been in scope for meeting the requirements of 10 CFR 54.4(a)(2). The staff reviewed the applicant's amended LRA to ensure that the new LRA tables include those components that have been brought into the scope of license renewal under 10 CFR 54.4(a)(2) because of their potential for spatial interaction with safety-related components. The staff finds the tables acceptable. Therefore, the staff's concern described in RAI 2.3A.2.2-1 for the BVS system is resolved. SER Sections 3.2.2.1 and 3.3B.2.3.41 document the staff's evaluation of new AMR results for the IP3 BVS system.

2.3B.2.5.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI response, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found an instance in which the applicant omitted components that should have been subject to an AMR. The applicant has satisfactorily resolved this issue as discussed in the preceding staff evaluation. On the basis of its review, the staff concludes that that the applicant has adequately identified the containment penetrations' 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).

2.3B.3 Scoping and Screening Results: Auxiliary Systems Unit 3

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:

- 2.3.3.1, "Spent Fuel Pit Cooling"
- 2.3.3.2, "Service Water"
- 2.3.3.3, "Component Cooling Water"
- 2.3.3.4, "Compressed Air"
- 2.3.3.5, "Nitrogen Systems"

- 2.3.3.6, “Chemical and Volume Control”
- 2.3.3.7, “Primary Water Makeup”
- 2.3.3.8, “Heating, Ventilation and Air Conditioning”
- 2.3.3.9, “Containment Cooling and Filtration”
- 2.3.3.10, “Control Room Heating, Ventilation and Cooling”
- 2.3.3.11, “Fire Protection—Water”
- 2.3.3.12, “Fire Protection—CO_2, Halon, and RCP Oil Collection Systems”
- 2.3.3.13, “Fuel Oil”
- 2.3.3.14, “Emergency Diesel Generators”
- 2.3.3.15, “Security Generators”
- 2.3.3.16, “Appendix R Diesel Generators”
- 2.3.3.17, “City Water”
- 2.3.3.18, “Plant Drains”
- 2.3.3.19, “Miscellaneous Systems In-Scope for (a)(2)”

The applicant created LRA Section 2.3.3.19 to capture all systems or portions of systems that are within the scope of license renewal only under 10 CFR 54.4(a)(2). Among the subsections identified in LRA Section 2.3.3.19, the staff identified the following auxiliary systems for simplified Tier 1 reviews:

- ammonia morpholine addition
- CL
- CW
- extraction steam
- floor drains
- hydrazine addition
- heater drain/moisture separator drains/vents
- lube oil
- low pressure steam dump
- main turbine generator
- nuclear equipment drains
- river water service
- main generator seal oil
- secondary plant sampling
- turbine hall closed cooling water

The staff conducted a more detailed Tier 2 review for all of the remaining auxiliary systems.

Staff’s RAIs

During its review, the staff noted that the applicant did not specifically identify components that were in scope under 10 CFR 54.4(a)(2) on the associated drawings. To determine that the applicant did not omit any components from scope under 10 CFR 54.4(a)(2), the staff asked the applicant to verify that it had included segments of the selected systems in scope under 10 CFR 54.4(a)(2). In the following RAIs, dated February 13, 2008, the staff asked that the applicant confirm its methodology for identifying nonsafety-related portions of systems with a potential for adversely affecting safety-related functions, in accordance with 10 CFR 54.4(a)(2), by describing the applicable portions of system piping that it included within the scope of license renewal under 10 CFR 54(a)(2):

- RAI 2.3B.3.1-2
- RAI 2.3B.3.2-1
- RAI 2.3B.3.3-1
- RAI 2.3B.3.13-1
- RAI 2.3B.3.14-2
- RAI 2.3B.3.18-1

In its response to the RAIs referenced above, dated March 12, 2008, the applicant stated that all of the component types identified by the staff on the license renewal drawings in question are within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2), and are subject to an AMR.

Based on its review, the staff finds the applicant's response to these RAIs acceptable because the applicant adequately explained that all of the component types identified by the staff are within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2), and subject to an AMR. The staff's concern described in these RAIs is resolved.

SER Sections 2.3B.3.1–2.3B.3.19, respectively, discuss the staff's review of the IP3 systems described in LRA Sections 2.3.3.1–2.3.3.19. The following sections discuss the staff's findings for these systems.

2.3B.3.1 IP3 Spent Fuel Pit Cooling System

2.3B.3.1.1 Summary of Technical Information in the Application

LRA Section 2.3.3.1 describes the SFPC system, which removes residual heat from the spent fuel pit. The SFPC loop consists of pumps (main and standby), a heat exchanger, filters, demineralizer, piping, valves, and instrumentation. The operating pump draws water from the pit for circulation through the heat exchanger and return. CCW cools the heat exchanger, which forms part of the CCW system pressure boundary. Loop piping is arranged so that any pipeline failure does not drain the spent fuel pit below the top of the stored fuel elements. The spent fuel pit pump suction line, which draws water from the pit, penetrates the spent fuel pit wall above the fuel assemblies. A purification loop circulates spent fuel pit water through the demineralizer and filter for purification. A portion of the system piping supporting the RWST purification loop with the spent fuel pit demineralizer forms part of the safety injection system pressure boundary. The system includes the spent fuel pit. Spent fuel storage racks at the bottom of the pit for spent fuel assemblies are a full-length, top-entry type made of stainless steel with Boral as a neutron absorber.

The SFPC system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function.

The spent fuel pit and the spent fuel racks are reviewed with the fuel storage buildings (LRA Section 2.4.3). Components supporting the CCW system pressure boundary are reviewed with the CCW systems (LRA Section 2.3.3.3). Components supporting the pressure boundary of the safety injection system are reviewed with the safety injection systems (LRA Section 2.3.2.4). A small number of components are reviewed with the primary water makeup systems (LRA Section 2.3.3.7).

LRA Tables 2.3.3-1-IP3 and 2.3.3-19-49-IP3 identify SFPC system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.1, UFSAR Sections 9.3 and 9.5, and a license renewal drawing using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.3.1, the staff identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

In RAI 2.3B.3.1-1, dated December 7, 2007, the staff noted that the UFSAR for IP3 references a backup SFPC system that operates in parallel with the normal SFPC system during refueling activities. Further, the LRA stated that the normal SFPC system is within the scope of license renewal under 10 CFR 54.4(a)(1), with the intended function of providing a pressure boundary for the CCW system and the safety injection system, and under 10 CFR 54.4(a)(2) because of possible physical interaction. The staff noted that the scope of license renewal excludes the backup spent fuel cooling system and requested that the applicant explain the exclusion of these components from scope.

In its response, dated January 4, 2008, the applicant stated that the backup SFPC system is a nonsafety-related system that has no functions under 10 CFR 54.4(a)(1) and is not relied on to perform a function that demonstrates compliance with 10 CFR 54.4(a)(3). The applicant explained that the system is normally drained when the plant is in normal power operation, such that its failure cannot prevent satisfactory accomplishment of any 10 CFR 54.4(a)(1) functions through spatial interaction. Lastly, the applicant explained that no components in the backup SFPC system are directly connected to safety-related equipment, and none meet the scoping requirements of 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), or 10 CFR 54.4(a)(3).

Based on its review, the staff finds the applicant's response to RAI 2.3B.3.1-1 acceptable because it adequately explained that the components in the backup SFPC system do not have intended functions under 10 CFR 54.4(a). The applicant adequately explained that the backup SFPC system is a nonsafety-related system, is normally drained when the plant is in normal power operation, and is not credited with performing functions identified in 10 CFR 54.4(a)(3). The staff's concern described in RAI 2.3B.3.1-1 is resolved.

The discussion of the staff's RAIs in SER Section 2.3B.3 details the disposition of RAI 2.3B.3.1-2, dated February 13, 2008.

2.3B.3.1.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and a drawing to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has appropriately identified the SFPC system 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).

2.3B.3.2 IP3 Service Water System

2.3B.3.2.1 Summary of Technical Information in the Application

LRA Section 2.3.3.2 describes the SW system, which supplies cooling water from the Hudson River to various heat loads in both the primary and secondary portions of the plant in a continuous flow to systems and components necessary for plant safety during either normal operation or abnormal or accident conditions. Sufficient redundancy of active and passive components maintains short- and long-term cooling to vital loads in accordance with the single-failure criterion. Six identical, vertical, centrifugal sump-type pumps at the intake structure supply service water to two independent discharge headers, each supplied by three pumps. An automatic, self-cleaning, rotary-type strainer in the discharge of each pump removes solids. Each header connects to an independent supply line. Either of the two supply lines can supply the essential loads while the other line supplies the nonessential loads. Three nonseismic-class pumps independent of the intake structure can supply an SW system backup by drawing suction from the discharge canal. The applicant credits one of these pumps with supplying service water during a safe shutdown following a fire.

The SW system supplies cooling water to nonessential loads, including SGBD heat exchangers, CW pump seal coolers, the turbine building CCW system, hydrogen coolers, exciter air coolers, and the isolated phase bus heat exchangers, to support normal operation.

The SW system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the SW system performs functions that support fire protection.

LRA Tables 2.3.3-2-IP3 and 2.3.3-19-56-IP3 identify SW system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.2, UFSAR Section 9.6.1, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

The staff's review of LRA Section 2.3.3.2 identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The discussion of the staff's RAIs in SER Section 2.3B.3 details the disposition of RAI 2.3B.3.2-1, dated February 13, 2008.

2.3B.3.2.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI response, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has appropriately identified the SW system 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).

2.3B.3.3 IP3 Component Cooling Water System

2.3B.3.3.1 Summary of Technical Information in the Application

LRA Section 2.3.3.3 describes the CCW system, which removes RCS residual and sensible heat via the RHR loop during plant shutdown, cools the letdown flow to the CVCS during power operation, and dissipates waste heat from various primary plant components. It also cools engineered safeguards and safe-shutdown components. The system has pumps, heat exchangers, distribution and return piping and valves, instruments, and controls to cool the following:

- RHR heat exchangers
- RCPs
- non-regenerative heat exchanger
- excess letdown heat exchanger
- CVCS seal water heat exchanger
- sample heat exchangers
- waste gas compressors
- reactor vessel support pads
- RHR pumps
- safety injection pumps
- recirculation pumps
- spent fuel pit heat exchanger
- charging pumps, fluid drive coolers, and crankcase
- gross failed fuel detector

Some of the CCW-cooled heat exchangers in other systems have no safety function; however, these nonsafety-related heat exchangers form parts of the CCW system pressure boundary. These heat exchangers are within the scope of license renewal with an intended function to maintain the pressure boundary but not to transfer heat. The heat exchangers within the CCW system are safety-related components.

The CCW system contains safety-related components relied upon to remain functional during and following DBEs. In addition, the CCW system performs functions that support fire protection.

A few components in the CCW system support the RHR system pressure boundary and are reviewed with the RHR systems (LRA Section 2.3.2.1). Component cooling water system components that service the safety injection system are reviewed with the safety injection systems (LRA Section 2.3.2.4).

LRA Table 2.3.3-3-IP3 and newly created Table 2.3.3-19-64-IP3 (see evaluation below) identify CCW system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.3, UFSAR Section 9.3, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.3.3, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

During its review of license renewal drawings for the CS system, the staff identified portions of the system that were not highlighted, indicating that sections of piping had no intended functions under 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3). In RAI 2.3A.2.2-1, dated February 13, 2008, the staff asked the applicant to identify any instances in which a system was identified as having no intended functions under 10 CFR 54.4(a)(1), but having nonsafety-related components not identified as within the scope of license renewal.

In its response, dated March 12, 2008, the applicant identified, in addition to the CS system, three other instances in which it had not identified nonsafety-related components as being within the scope of license renewal under 10 CFR 54.4(a)(2). SER Sections 2.3A.2.2, 2.3A.3.3, and 2.3B.2.5 discuss the staff's evaluation of the affected systems. The applicant further explained that it should have identified the CCW systems for IP2 and IP3 and the IP3 BVS system as meeting the requirements of 10 CFR 54.4(a)(2). In these instances, the applicant amended the LRA for IP3 CCW system to include the following:

a) LRA Table 2.3.3-19-A-IP3 would reflect the CCW system as a miscellaneous system within the scope of license renewal pursuant to 10 CFR 54.4(a)(2).

b) Removal of the CCW system from the list of IP3 systems not reviewed for spatial interaction, pursuant to 10 CFR 54.4(a)(2).

c) Revision of LRA Table 2.3.3-19-B-IP3 to reflect that the CCW system now has components subject to an AMR pursuant to 10 CFR 54.4(a)(2).

d) Creation of a new LRA Table 2.3.3-19-64-IP3 for the six added component types in the CCW system for nonsafety-related components potentially affecting safety function, subject to an AMR.

e) Creation of a new LRA Table 3.3.2-19-64-IP3 for the six added component types, their materials, environments, and AMPs.

Based on its review, the staff finds the applicant's response to RAI 2.3A.2.2-1 for the IP3 CCW system acceptable because it adequately explained that the applicant's reevaluation of safety-related systems identified components that should have been within scope for meeting the requirements of 10 CFR 54.4(a)(2). Additionally, the applicant amended the LRA to include portions of the CCW system within the scope of license renewal under 10 CFR 54.4(a)(2). The staff reviewed the applicant's addition of new tables to the LRA to ensure that they include those components with the potential for spatial interaction with safety-related components as within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2). The staff's concern described in RAI 2.3A.2.2-1 for the IP3 CCW system is resolved. SER Section 3.3.2.1 documents the staff's evaluation of new AMR results for the IP3 CCW system.

The discussion of the staff's RAIs in SER Section 2.3B.3 details the disposition of RAI 2.3B.3.3-1, dated February 13, 2008.

2.3B.3.3.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found an instance in which the applicant omitted components that should have been subject to an AMR. The applicant has satisfactorily resolved this issue as discussed in the preceding staff evaluation. On the basis of its review, the staff concludes that the applicant has appropriately identified the CCW system 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).

2.3B.3.4 IP3 Compressed Air Systems

2.3B.3.4.1 Summary of Technical Information in the Application

LRA Section 2.3.3.4 describes the compressed air systems, including the instrument air and station air systems. The instrument air system continuously supplies dry, oil-free air from duplicate compressors with duplicate dryers and filters for pneumatic instruments and controls. Each compressor discharges into a common air receiver and takes a backup supply from the station air system. To meet current and future instrument air loads, a third compressor-dryer package is available to supply the conventional plant. This compressor also can supply the station air system with backup air, if necessary. The system has compressors, dryers, filters, receivers, distribution piping and valves, instruments, and controls. Items essential for safe operation and safe cooldown have air reserves or gas bottles that enable the equipment to function safely until its air supply resumes. The instrument air system includes piping, valves, and controls supporting this air reserve function, but does not include air or gas bottles, which are part of other systems.

The station air system, which supplies compressed air for pneumatic tools, CW pump priming, and miscellaneous cleaning and maintenance purposes throughout the primary and secondary plants, has diesel-driven and motor-driven air compressors, inter- and after-coolers, a receiver, piping, valves, instruments, and controls. Distribution piping to the containment includes containment isolation valves.

The compressed air system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the compressed air system performs functions that support fire protection and SBO.

LRA Tables 2.3.3-4-IP3, 2.3.3-19-29-IP3, and 2.3.3-19-48-IP3 identify compressed air system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.4, UFSAR Section 9.6.3, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3B.3.4.3 Conclusion

The staff reviewed the LRA, UFSAR, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the compressed air system 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).

2.3B.3.5 IP3 Nitrogen System

2.3B.3.5.1 Summary of Technical Information in the Application

LRA Section 2.3.3.5 describes the nitrogen system, which supplies motive gas as a backup to the instrument air supply and nitrogen to various components for process functions (including cover gas, calibration gas, purge gas, and gas for operation of level instrumentation). Nitrogen enters containment through several penetrations that must isolate for containment isolation capability under accident conditions. The containment penetration pressurization system also has nitrogen-filled components not included with this system code.

The nitrogen system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the nitrogen system performs functions that support fire protection.

A small number of nitrogen system components are reviewed with the AFW systems (LRA Section 2.3.4.3).

LRA Tables 2.3.3-5-IP3 and 2.3.3-19-37-IP3 identify nitrogen system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.5; UFSAR Sections 7.3, 9.6.2.5, 9.9.2, and 10.2.6; and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3B.3.5.3 Conclusion

The staff reviewed the LRA, UFSAR, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the nitrogen system 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).

2.3B.3.6 IP3 Chemical and Volume Control System

2.3B.3.6.1 Summary of Technical Information in the Application

LRA Section 2.3.3.6 describes the CVCS, which controls RCS inventory (amounts of makeup and letdown) and chemistry (RCS boron concentration and other chemical additions). The system cleans up reactor coolant by degasification and purification, injects seal water to the RCPs, depressurizes the RCS via a pressurizer auxiliary spray flowpath, and injects control poison in the form of boric acid solution from the boric acid storage tanks.

During normal plant operation, reactor coolant letdown flows through the shell side of the regenerative heat exchanger, which reduces its temperature by transferring heat to the charging fluid. The coolant then flows through a letdown orifice, which regulates flow and reduces the coolant pressure. The cooled, low-pressure water leaves the reactor containment and enters the PAB. After passing through the nonregenerative heat exchanger and one of the mixed-bed demineralizers, the fluid flows through the reactor coolant filter and enters the VCT.

The coolant flows from the VCT to three positive-displacement, variable-speed charging pumps, which raise the pressure above that in the RCS. The high-pressure water flows from the PAB to the reactor containment along two parallel paths, one returning directly to the RCS through the tube side of the regenerative heat exchanger to the RCS cold leg, and the other injecting water into the RCP seals through seal injection filters. The RCP seal water returns to the CVCS through a seal water filter and heat exchanger back to the VCT.

The RWST and the boric acid storage tanks can provide borated water to the charging system. The RWST is available to the charging pumps for injection of borated water. The boric acid system has boric acid transfer pumps, a boric acid filter, and storage tanks to maintain a large inventory of concentrated boric acid solution.

The CVCS contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the CVCS performs functions that support fire protection and ATWS.

CVCS components that maintain the RCS pressure boundary are reviewed with the RCS pressure boundary (LRA Section 2.3.1.3). A small number of system components are reviewed with the primary water makeup systems (LRA Section 2.3.3.7) and with the CCW systems (LRA Section 2.3.3.3).

LRA Tables 2.3.3-6-IP3 and 2.3.3-19-11-IP3 identify CVCS component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.6, UFSAR Section 9.2.2, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3B.3.6.3 Conclusion

The staff reviewed the LRA, UFSAR, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the CVCS 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).

2.3B.3.7 IP3 Primary Water Makeup System

2.3B.3.7.1 Summary of Technical Information in the Application

LRA Section 2.3.3.7 describes the primary water makeup system, which supplies makeup water to primary plant systems as required in support of normal plant operation. Among other components, this system includes tanks, piping, valves, and pumps. It is also a source of fire water to the containment. The system has a containment penetration and one safety-related component part of the RWST pressure boundary.

The demineralized water system is evaluated with the primary water system. The system supplies demineralized water for normal plant operation and refueling activities to the spent fuel pit, refueling cavity, and RWST; for decontamination, hydrostatic testing, and flushing during refueling outages; for condensate polisher regeneration through the sluice water pumps; and for fire protection in containment.

The system includes safety-related position indicators for the containment penetration isolation valves, which are in the primary water makeup system; therefore, this system has no safety-related mechanical function.

The primary water makeup system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the primary water makeup system performs functions that support fire protection.

Portions of the primary water makeup system that support the RWST pressure boundary are reviewed with the safety injection system (LRA Section 2.3.2.4).

LRA Tables 2.3.3-7-IP3, 2.3.3-19-15-IP3, and 2.3.3-19-42-IP3 identify primary water makeup system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.7.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.7; UFSAR Sections 9.2.2, 9.6.2.3, and 9.11.1; and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3B.3.7.3 Conclusion

The staff reviewed the LRA, UFSAR, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the primary water makeup system 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).

2.3B.3.8 IP3 Heating, Ventilation and Air Conditioning Systems

2.3B.3.8.1 Summary of Technical Information in the Application

LRA Section 2.3.3.8 describes the HVAC systems, which maintain the area environment for personnel and equipment. HVAC systems for specific buildings or areas of buildings, including portions of ventilation systems serving various areas of the plant, generally have separate system codes. The HVAC system includes fans and dampers for the electrical tunnels, intake structure, and fire pump house and portable ventilation equipment for safe-shutdown requirements.

The IP3 HVAC systems evaluation includes the following HVAC systems:

- control building heating and ventilation
- fire barriers
- fuel storage building heating and ventilation
- HVAC
- PAB heating and ventilation
- plant vent
- security heating and ventilation
- vapor containment purge and supply
- vapor containment pressure relief
- Appendix R diesel generator heating and ventilation
- EDG building heating and ventilation

LRA Section 2.3.3.9 describes containment cooling and filtration, and LRA Section 2.3.3.10 discusses the control room HVAC.

The control building heating and ventilation system heats and ventilates the 15-foot and 33-foot elevations of the control building and ventilates battery rooms 31, 32, and 34 to maintain hydrogen concentrations below maximum acceptable limits during normal plant operation. The system includes dampers, ductwork, heaters, and fans.

The fire barriers system has structural barriers and components for penetrations to prevent or delay the spread of fire to adjoining areas. This system includes fire doors and fire dampers that also support the HVAC systems like that for the diesel generator building. The fire doors and fire dampers are evaluated with their respective structures for their fire barrier function. Fire damper housings that form part of an HVAC system pressure boundary within the scope of license renewal are included in the HVAC evaluation to maintain the housing function of HVAC system support.

The fuel storage building heating and ventilation system heats and ventilates the fuel storage building, minimizes leakage of unfiltered air from the building during fuel-handling operations, and filters building exhaust. The system has two fresh-air-tempering units with supply fans and heaters; exhaust-roughing, HEPA, and carbon filters; an exhaust fan; motor-operated dampers;

and ducts. During normal operation, the fresh-air-tempering units and exhaust fan ventilate and heat the fuel storage building with exhaust air, which passes through the roughing and HEPA filters. During fuel handling, the system maintains a slight negative pressure in the building and passes all ventilation exhaust through the roughing, HEPA, and charcoal filters before release through the plant vent. Originally credited in the fuel-handling accident, the system has no safety functions because the new analysis (described in UFSAR Section 14.2.1), which uses the alternate source term, no longer assumes operation of the ventilation system or any holdup of the radionuclides released from the spent fuel pit.

The HVAC system maintains the area environment for personnel and equipment. HVAC systems for specific buildings or areas of buildings generally have a separate system code. The HVAC system includes portions of various ventilation systems serving different areas of the plant. The HVAC system includes fans and dampers for various areas, such as the electrical tunnels, intake structure, and fire pump house. This system also includes portable ventilation equipment supporting safe-shutdown requirements.

The PAB heating and ventilation system heats and ventilates the waste hold-up tank pit and the PAB enclosed spaces. The waste hold-up tank pit contains the waste hold-up tanks which are central collection points for liquid radioactive waste. The PAB houses equipment and components required for normal plant operation as well as accident mitigation, including pumps for the CCW, safety injection, RHR, CS, and other systems. Also located in the PAB are tanks for the waste disposal system that collect radioactive liquids and gases. The PAB heating and ventilation system maintains an environment for personnel and equipment during normal operating and post-accident conditions. The PAB and tank pit are ventilated by a balanced flow between supply and exhaust, maintaining a slight negative pressure in the PAB. Air supplied to each building enters areas of low contamination. A set of fans exhausts air out the plant vent from areas of higher contamination after passing it through filters. No dose consequence analyses credit filtration.

The plant vent system with its plant vent duct and vent flow monitoring instrumentation provides a flowpath for plant ventilation systems to exhaust to the atmosphere. The offsite dose analyses do not credit the plant vent; however, this vent is the release point for control room dose calculations and its structural integrity must be maintained for this purpose.

The security heating and ventilation system heats and ventilates the security building and supports operation of the security propane generator. The system includes fans, heaters, and dampers.

The vapor containment purge and supply system filters, monitors, and purges containment air to the plant vent for exhaust to the environment and supplies makeup air to the containment. Operation of the purge system during reactor shutdown maintains radioactivity concentrations inside containment within acceptable limits. The purge system is isolated to maintain containment integrity whenever the plant is above the cold shutdown condition. The system has filters, heating coils, fans, penetration isolation valves, ductwork, instruments, and controls. Some system components share a common pressure boundary with PAB heating and ventilation system components.

The vapor containment pressure relief system relieves the normal pressure changes in containment during reactor power operation. This system consists of a pressure relief line equipped with three isolation valves, one inside and two outside the containment. The pressure relief line discharges through roughing, HEPA, and charcoal filters to the plant vent.

The IP3 Appendix R diesel generator has its own enclosure in the yard. Ventilation to the engine is by exhaust fans that draw outside air through covered intake dampers or louvers when required. Exhaust fans that draw outside air in through louvers provide ventilation to the electrical enclosure and the battery enclosure. This equipment is required to support operation of the IP3 Appendix R diesel generator credited for both 10 CFR Part 50, Appendix R, requirements and SBO response.

The IP3 EDG building houses and protects the EDGs. The rooms have outside-air fixed louvers, pneumatically-operated adjustable louvers, and exhaust fans with motor-operated discharge dampers. The pneumatically-operated dampers operate from control air supplied by the EDG starting air system. EDG building ventilation is relied on to support EDG operations during DBAs and regulated events.

The HVAC system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the HVAC system performs functions that support fire protection.

Instrument air volume tanks, tubing, and valves in the vapor containment pressure relief system needed for the containment penetration valves to close are reviewed with the compressed air systems (LRA Section 2.3.3.4).

LRA Tables 2.3.3-8-IP3, 2.3.3-19-21-IP3, 2.3.3-19-39-IP3, 2.3.3-19-60-IP3, and 2.3.3-19-61-IP3 identify HVAC system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.8.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.8; UFSAR Sections 1.3.6, 5.3.2.3, 5.3.2.5, 9.5, 9.6.2.2, 9.8, and 14.2.1; and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3B.3.8.3 Conclusion

The staff reviewed the LRA, UFSAR, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the HVAC system 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).

2.3B.3.9 IP3 Vapor Containment Building Ventilation System

2.3B.3.9.1 Summary of Technical Information in the Application

LRA Section 2.3.3.9 describes the IP3 vapor containment building ventilation system, which by recirculation cooling and filtration removes normal heat losses from equipment and piping in containment during plant operation, ensures personnel access and safety during shutdown, and depressurizes the containment vessel following an accident. Air recirculation cooling and filtering during normal operation is achieved using all five air-handling units discharging to a common header ductwork distribution system. Each air-handling unit consists of cooling coils, a centrifugal fan with direct-drive motor, and a distribution header. In an accident, the system diverts the flowpath first through a compartment with moisture separators, HEPA filters, and charcoal filters. Dose analyses for some accidents credit the HEPA filters but not the charcoal filters for fission product removal.

The vapor containment building ventilation system contains safety-related components relied on to remain functional during and following DBEs. In addition, the vapor containment building ventilation system performs functions that support fire protection.

LRA Table 2.3.3-9-IP3 identifies vapor containment building ventilation system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.9.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.9, UFSAR Sections 5.3.2.2 and 6.4.2, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3B.3.9.3 Conclusion

The staff reviewed the LRA, UFSAR, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the vapor containment building ventilation system 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).

2.3B.3.10 IP3 Control Room Heating, Ventilation and Cooling System

2.3B.3.10.1 Summary of Technical Information in the Application

The IP3 Appendix R diesel generator has its own enclosure in the yard. Ventilation to the engine is by exhaust fans that draw outside air through covered intake dampers or louvers when required. Exhaust fans that draw outside air in through louvers provide ventilation to the electrical enclosure and the battery enclosure. This equipment is required to support operation of the IP3 Appendix R diesel generator credited for both 10 CFR Part 50, Appendix R, requirements and SBO response.

The IP3 EDG building houses and protects the EDGs. The rooms have outside-air fixed louvers, pneumatically-operated adjustable louvers, and exhaust fans with motor-operated discharge dampers. The pneumatically-operated dampers operate from control air supplied by the EDG starting air system. EDG building ventilation is relied on to support EDG operations during DBAs and regulated events.

The control room HVAC system contains safety-related components relied on to remain functional during and following DBEs. In addition, the control room heating, ventilation and cooling system performs functions that support fire protection.

LRA Table 2.3.3-10-IP3 identifies control room HVAC component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.10.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.10, UFSAR Section 9.9, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3B.3.10.3 Conclusion

The staff reviewed the LRA, UFSAR, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the control room HVAC system 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).

2.3B.3.11 IP3 Fire Protection – Water

2.3B.3.11.1 Summary of Technical Information in the Application

LRA Section 2.3.3.11 describes the fire protection system, which provides fire protection for the station through the use of water, foam, Halon 1301, detection and alarm systems, and rated fire barriers, doors, and dampers. The fire water system components include fire water and foam subsystem pumps, piping, hydrants, hose reels, valves, tanks, and drains. This system also includes the fuel oil supply to the fire pump house diesel. Fire protection systems include the fire detection and alarm system, as described below. LRA Section 2.3.3.12 describes the CO_2 and Halon 1301 systems. LRA Section 2.3.3.8 discusses the fire barrier system code.

The fire protection water distribution system has two ground-level storage tanks supplied by the city water distribution system. Heating provisions for the storage tanks consist of two sets of dual electric heaters and two sets of dual circulating pumps. The pumping facilities maintain system pressure and, using jockey pumps, supply makeup for system leakage. Two main fire pumps (one electric motor driven and the other diesel engine driven) provide an automatic water supply during a fire. The pumping facilities provide flow and pressure requirements for the water-based fire protection systems. The fire protection water distribution system consists of outdoor underground and aboveground piping and indoor distribution piping in all buildings except the containment building. Demineralized water piping is for fire protection inside containment. IP3 underground piping has two connections with the IP1 fire protection system, providing defense in depth for the IP3 fire protection systems in terms of both water supply and pumping capacity. The distribution system also has isolation valves, strainers, hose stations, and outdoor hydrants. The distribution piping delivers anticipated fire water requirements to individual suppression systems. The yard hydrants provide effective hose stream protection for exterior hazards and for supplementary use for fire conditions within the main buildings of the plant. The water-based fire suppression systems include the wet pipe sprinkler systems, preaction sprinkler systems, deluge water spray systems, foam water spray systems, hydrants, and hose stations. To prevent local flooding, areas with safety-related equipment, or equipment required for safe plant shutdown with automatically operated fire protection, have either gravity or pump drains to handle the maximum quantity of spray water. The fire water system includes plant drain components that protect safety-related equipment from the effects of Class III component failures. The fire water system can supply makeup to the spent fuel pit. While not a safety function, this feature of the fire water system is included as a license renewal intended function.

According to the LRA, the fire protection—water system has no intended function under 10 CFR 54.4(a)(1). The scoping and screening methodology identified the following fire water system intended functions, in accordance with 10 CFR 54.4(a)(2):

- Maintain integrity of nonsafety-related components such that no physical interaction with safety-related components can prevent satisfactory accomplishment of a safety function.
- Provide a backup source of makeup water to the spent fuel pit.

The scoping and screening methodology also identified the following fire protection—water system intended functions, in accordance with 10 CFR 54.4(a)(3):

- Provide fixed automatic and manual fire suppression (including hydrants, hose stations and portable extinguishers) to extinguish fires in vital areas of the plant (10 CFR 50.48).

- Ensure adequate protection of safety-related equipment from water damage in areas susceptible to flooding (10 CFR 50.48).

The fire detection and alarm system transmits fire alarm and supervisory signals to the control room audible and visual alarms. The system has signals for actuation of fire detectors, status indicators for most installed fire suppression systems, control and indicating lights for the fire pumps, level indicators for the fire water storage tanks, and door status indicator lights for operator notification of critical fire doors. The fire detection and alarm system is primarily electrical, but includes instrument air-operated valve and piping parts of an electrical tunnel fire alarm that actuates upon a loss of pressure within the piping.

The fire detection and alarm system has no intended function under 10 CFR 54.4(a)(2). The scoping and screening methodology identified the following fire detection and alarm system intended function, in accordance with 10 CFR 54.4(a)(3):

- Support a fire alarm in the electrical tunnel (10 CFR 50.48).

The mechanical portions of the fire detection and alarm system are within the scope of license renewal, but the pressure boundary for the instrument air piping is not required for the system to perform its intended function. Therefore, the components of the fire detection and alarm system are not subject to an AMR. The system drain portion is evaluated with plant drains (LRA Section 2.3.3.18). The fuel oil subsystem components are evaluated with fuel oil systems (LRA Section 2.3.3.13).

Nonsafety-related components not evaluated with other systems but whose failure could prevent satisfactory accomplishment of safety functions are evaluated with miscellaneous systems within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2) (LRA Section 2.3.3.19). The remaining fire protection—water system and fire detection and alarm system components are evaluated in LRA Section 2.3.3.12.

LRA Tables 2.3.3-11-IP3 and 2.3.3-19-20-IP3 identify the fire protection—water system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.11.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.11, UFSAR Sections 9.6.2.3 and 9.6.2.4, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

The staff also reviewed NRC fire protection SERs for IP3, dated September 21, 1973; March 6, 1979; May 2, 1980; November 18, 1982; December 30, 1982; February 2, 1984; April 16, 1984; January 7, 1987; September 9, 1988; October 21, 1991; April 20, 1994; and January 5, 1995.

The staff also reviewed the IP3 commitments associated with 10 CFR 50.48 (i.e., an approved fire protection program) using its commitment responses to BTP APCSB 9.5-1 and Appendix A to BTP APCSB 9.5-1.

During its review of LRA Section 2.3.3.11, the staff identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

In RAI 2.3B.3.11-1, dated October 24, 2007, the staff asked the applicant to explain why LRA license renewal drawings indicate that certain fire protection system components are not subject to an AMR. Specifically, license renewal drawing LRA-9321-40903-0 indicates that the following fire protection system component is not subject to an AMR (i.e., the component is not highlighted in green):

- FP-T-4 pneumatic tank and components

License renewal drawing LRA-9321-40913-001-0 indicates that the following fire protection system components are not subject to an AMR (i.e., these components are not highlighted in green):

- turbine generator building foam system
- turbine building wall spray system No. 3
- yard transformer separation spray system
- main transformer No. 31 deluge system
- main transformer No. 32 deluge system
- unit auxiliary transformer deluge system
- station auxiliary transformer deluge system
- north half sprinkler No. 6
- boiler room sprinkler system
- sprinkler system for AFW pump room
- lube oil storage tank
- lube oil reservoir
- manual/spray system No. 2 for the boiler feed pump
- hydrogen seal oil unit
- manual boiler feed pump oil accumulators Nos. 31 and 32
- boiler feed console pump

The staff requested that the applicant verify whether the above components are within the scope of license renewal, as required by 10 CFR 54.4(a), and subject to an AMR, in accordance with 10 CFR 54.21(a)(1). The staff requested that the applicant justify excluding any of these components from the scope of license renewal and an AMR.

In its response, dated November 16, 2007, the applicant provided scoping and screening results applicable to fire protection system components. With respect to the FP-T-4 pneumatic tank and components indicated on license renewal drawing LRA-9321-40903-0, the applicant stated the following:

> FP-T-4 pneumatic tank and components are not required for compliance with 10 CFR 50.48 and are not described in fire protection SERs, for the response to BTP APCSB 9.5-1, Appendix A. The pneumatic tank and components were used in the past to aid the two jockey pumps in maintaining fire loop pressure. They are no longer used and are isolated from the rest of the system by normally closed valve FP-84. Jockey pumps FP-P-5 and 6 maintain sufficient pressure on the fire protection piping system during non-fire conditions to prevent unnecessary starting of the main fire pumps.

Based on its review, the staff finds the applicant's response acceptable because the applicant clarified that it no longer relies on the FP-T-4 pneumatic tank and components to demonstrate compliance with 10 CFR 50.48. Jockey pumps FP-P-5 and FP-P-6 maintain sufficient pressure on the fire protection piping system during non-fire conditions to prevent the main fire pumps from unnecessarily starting.

With respect to license renewal drawing LRA-9321-40913-001-0, the applicant addressed each item in the staff's RAI. For the turbine generator building foam systems, the applicant stated the following:

> Fluid-containing portions of the turbine generator building foam systems are included with miscellaneous systems in-scope in compliance with 10 CFR 54.4(a)(2) and are subject to an AMR. The AMR for the fluid-containing portions of the systems are in LRA Table 3.3.2-19-20-IP3. Based on discussion in the SER for IP3 dated March 6, 1979, the foam suppression systems for various areas in the turbine building are considered to meet the scoping requirements of 10 CFR 54.4(a)(3), in addition to 10 CFR 54.4(a)(2). The AMR results in LRA Table 3.3.2-11 IP3 are applicable to the portions of the turbine generator building foam systems normally containing air.

Based on its review, the staff finds the applicant's response acceptable because it indicated that the generator building foam systems are included in the scope of license renewal with miscellaneous systems, in accordance with 10 CFR 54.4(a)(2), and are subject to an AMR.

For the turbine building wall spray system No. 3, the applicant stated the following:

> The turbine building wall spray system No. 3 is in-scope as shown on drawing LRA-9321- 40913-001-0, coordinates D5. The absence of boundary flags where highlighted piping enters a text box indicates that the portion of the system described in the text box is in-scope and subject to an AMR.

Based on its review, the staff finds the applicant's response acceptable because it indicated that the turbine building wall spray system No. 3 is within the scope of license renewal and subject to an AMR.

For the yard transformer separation spray system, the applicant stated the following:

> The yard transformer separation spray system is in-scope as shown on drawing LRA-9321- 40913-001-0, coordinates D5. The absence of boundary flags where highlighted piping enters a text box indicates that the portion of the system described in the text box is in-scope and subject to an AMR.

Based on its review, the staff finds the applicant's response acceptable because it indicated that the yard transformer separation spray system is within the scope of license renewal and subject to an AMR as shown on license renewal drawing LRA-9321- 40913-001-0.

For the main transformer No. 31 deluge system, the applicant stated the following:

> The deluge system and associated components for main transformer No. 31, adjacent to the control building, were initially determined to have no license renewal intended function. They were considered as required only to protect the transformer, to satisfy requirements of the plant insurance carrier. However, the spray systems provide for defense-in-depth, in addition to installed 3-hour rated fire barriers between the transformer and the turbine building, and are now considered in-scope and subject to an AMR. Applicable component types that are subject to an AMR are included in LRA Table 2.3.3-11-IP3, with the AMR results provided in LRA Table 3.3.2-11-IP3.

Based on its review, the staff finds the applicant's response acceptable because it clarified that (1) the main transformer No. 31 deluge system and its associated components have no license renewal intended function and (2) the water spray systems provide for defense in depth, in addition to the installed 3-hour-rated fire barriers, and are considered within the scope of license renewal and subject to an AMR.

For the main transformer No. 32 deluge system, the applicant stated the following:

> The deluge system and associated components for main transformer No. 32, adjacent to the control building, were initially determined to have no license renewal intended function. They were considered as required only to protect the transformer to satisfy requirements of the plant insurance carrier. However, the spray systems provide for defense-in-depth, in addition to installed 3-hour rated fire barriers between the transformer and the turbine building, and are now considered in-scope and subject to an AMR. Applicable component types that are subject to an AMR are included in LRA Table 2.3.3-11-IP3, with the AMR results provided in LRA Table 3.3.2-11-IP3.

Based on its review, the staff finds the applicant's response acceptable because it clarified that (1) the main transformer No. 32 deluge system and its associated components have no license renewal intended function and (2) the water spray systems provide for defense in depth, in addition to the installed 3-hour-rated fire barriers, and are considered within the scope of license renewal and subject to an AMR.

For the unit auxiliary transformer deluge system, the applicant stated the following:

> The deluge system and associated components for the unit auxiliary transformer,

adjacent to the control building, were initially determined to have no license renewal intended function. They were considered as required only to protect the transformer to satisfy requirements of the plant insurance carrier. However, the spray systems provide for defense-in-depth, in addition to installed 3-hour rated fire barriers between the transformer and the turbine building, and are now considered in-scope and subject to an AMR. Applicable component types that are subject to an AMR are included in LRA Table 2.3.3-11-IP3, with the AMR results provided in LRA Table 3.3.2-11-IP3.

Based on its review, the staff finds the applicant’s response acceptable because it clarified that (1) the unit auxiliary transformer deluge systems and their associated components have no license renewal intended function and (2) the water spray systems provide for defense in depth, in addition to the installed 3-hour-rated fire barriers, and are considered within the scope of license renewal and subject to an AMR.

For the station auxiliary transformer deluge system, the applicant stated the following:

> The deluge system and associated components for the station auxiliary transformer, adjacent to the control building, were initially determined to have no license renewal intended function. They were considered as required only to protect the transformer to satisfy requirements of the plant insurance carrier. However, the spray systems provide for defense-in-depth, in addition to installed 3-hour rated fire barriers between the transformer and the turbine building, and are now considered in-scope and subject to an AMR. Applicable component types that are subject to an AMR are included in LRA Table 2.3.3-11-IP3, with the AMR results provided in LRA Table 3.3.2-11-IP3.

Based on its review, the staff finds the applicant’s response acceptable because it clarified that (1) the station auxiliary transformer deluge systems and their associated components have no license renewal intended function and (2) the water spray systems provide for defense in depth, in addition to installed 3-hour-rated fire barriers, and are considered within the scope of license renewal and subject to an AMR.

For the north half sprinkler No. 6, the applicant stated the following:

> Turbine building north half sprinkler No. 6 system was initially determined to have no license renewal intended function, since a fire in the area protected by the system cannot disable the credited safe-shutdown equipment, which is located outside the area. However, based on discussion in the SER for IP3 dated March 6, 1979, the turbine building north half sprinkler No. 6 system provides defense-in-depth, in addition to hose stations throughout the turbine building, and fire barriers between the turbine building and control building. The system is therefore considered within the scope of license renewal and subject to an AMR, in accordance with 10 CFR 54.4(a)(3). The AMR results in LRA Table 3.3.2-11-IP3 are applicable to the turbine building north half sprinkler system No. 6.

Based on its review, the staff finds the applicant’s response acceptable because it indicated that the turbine building north half sprinkler No. 6 system is within the scope of license renewal and subject to an AMR.

For the boiler room sprinkler system, the applicant stated the following:

> The boiler room sprinkler system is not required to satisfy the provisions of BTP APCSB 9.5-1, Appendix A and is not credited in fire protection SERs. The boiler room sprinkler system is maintained to satisfy requirements of the plant insurance carrier. The boiler room sprinkler system does not protect safety-related equipment and is not located near any building housing safety-related equipment. Fire in the area of the boiler room will be contained within that area and not affect safe-shutdown equipment, due to its location and limited amount of combustibles.

Based on its review, the staff finds the applicant's response acceptable because it clarified that the provisions of 10 CFR 50.48 do not require the boiler room sprinkler system and components because this system does not protect safety-related equipment and is not located near any building housing safety-related equipment.

For the sprinkler system for AFW pump room, the applicant stated the following:

> The sprinkler system for the auxiliary feedwater pump room is in-scope as shown on drawing LRA-9321-40913-001-0, coordinate (E8). The absence of boundary flags where the highlighted piping enters the text box indicates that the portion of the system described in the text box is in-scope and subject to an AMR.

Based on its review, the staff finds the applicant's response acceptable because it indicated that the sprinkler system for the AFW pump room is within the scope of license renewal and subject to an AMR.

For the lube oil storage tank foam system, the applicant stated the following:

> Fluid-containing portions of the LO storage tank foam suppression systems are included with miscellaneous systems in-scope pursuant to 10 CFR 54.4(a)(2) and are subject to an AMR. The AMR results for the fluid-containing portions of the system are included in LRA Table 3.3.2-19-20-IP3. Based on discussion in the SER for IP3 dated March 6, 1979, the LO storage tank foam suppression system is considered as meeting the scoping requirements of 10 CFR 54.4(a)(3), in addition to 10 CFR 54.4(a)(2). The AMR results in LRA Table 3.3.2-11-IP3 are applicable to the portions of the LO storage tank foam suppression system normally containing air.

Based on its review, the staff finds the applicant's response acceptable because it clarified that lube oil storage tank foam suppression systems are included in the scope of license renewal with miscellaneous systems in accordance with 10 CFR 54.4(a)(2) and are subject to an AMR.

For the lube oil reservoir foam system, the applicant stated the following:

> Fluid-containing portions of the LO reservoir foam suppression systems are included with miscellaneous systems in-scope pursuant to 10 CFR 54.4(a)(2) and are subject to an AMR. The AMR results for the fluid-containing portions of the system are provided in LRA Table 3.3.2-19-20-IP3. Based on discussion in

> the SER for IP3 dated March 6, 1979, the LO reservoir foam suppression system is considered as meeting the scoping requirements of 10 CFR 54.4(a)(3), in addition to 10 CFR 54.4(a)(2). The AMR results in LRA Table 3.3.2-11-IP3 are applicable to the portions of the LO reservoir foam suppression system normally containing air.

Based on its review, the staff finds the applicant's response acceptable because it clarified that the lube oil reservoir foam suppression systems are included in the scope of license renewal with miscellaneous systems, in accordance with 10 CFR 54.4(a)(2), and are subject to an AMR.

For the manual/spray system No. 2 for the boiler feed pump, the applicant stated the following:

> The manual/spray system No. 2 for the boiler feed pump is not required to satisfy the provisions of BTP APCSB 9.5-1, Appendix A, and is not credited in fire protection SERs. The manual spray system No. 2 satisfies requirements of the plant insurance carrier. SER Section 5.9.1 states there is no safety-related equipment or electrical cables located within the turbine building. SER Section 5.9.6 discusses modifications to provide three-hour fire-rated doors and dampers in the barriers between the turbine building and the control building, as well as upgrading penetrations to a three-hour fire-rating.

Based on its review, the staff finds the applicant's response acceptable because it explained that the manual/spray system No. 2 for the boiler feed pump does not have a license renewal intended function. The manual/spray system No. 2 for the boiler feed pump does not provide a fire protection function as part of the applicant's approach to complying with 10 CFR 50.48; thus, the associated fire protection components are not within the scope of license renewal.

For the hydrogen seal oil unit foam system, the applicant stated the following:

> Fluid-containing portions of the H_2 seal oil unit foam suppression systems are included with miscellaneous systems in-scope pursuant to 10 CFR 54.4(a)(2) and are subject to an AMR. The AMR results for the fluid-containing portions of the system are included in LRA Table 3.3.2-19-20-IP3. Based on discussion in the SER for IP3 dated March 6, 1979, the H_2 seal oil unit foam suppression system is considered as meeting the scoping requirements of 10 CFR 54.4(a)(3), in addition to 10 CFR 54.4(a)(2). The AMR results in Table 3.3.2-11-IP3 are applicable to the portions of the H_2 seal oil unit foam suppression system normally containing air.

Based on its review, the staff finds the applicant's response acceptable because it clarified that hydrogen seal oil unit foam suppression systems are included in the scope of license renewal with miscellaneous systems, in accordance with 10 CFR 54.4(a)(2), and are subject to an AMR.

For the manual boiler feed pump oil accumulators Nos. 31 and 32 foam system, the applicant stated the following:

> Fluid-containing portions of the manual boiler feed pump oil accumulators No. 31 and 32 foam suppression systems are included with miscellaneous systems in-scope pursuant to 10 CFR 54.4(a)(2) and are subject to an AMR. The AMR results for the fluid-containing portions of the system are shown in LRA

Table 3.3.2-19-20-IP3. Based on discussion in the SER for IP3 dated March 6, 1979, the manual boiler feed pump oil accumulators No. 31 and 32 foam suppression system is considered as meeting the scoping requirements of 10 CFR 54.4(a)(3), in addition to 10 CFR 54.4(a)(2). The AMR results in LRA Table 3.3.2-11-IP3 are applicable to the portions of the manual boiler feed pump oil accumulators No. 31 and 32 foam suppression system normally containing air.

Based on its review, the staff finds the applicant's response acceptable because it clarified that the manual boiler feed pump oil accumulators No. 31 and 32 foam suppression systems are included in the scope of license renewal with miscellaneous systems, in accordance with 10 CFR 54.4(a)(2), and are subject to an AMR.

For the boiler feed console pump foam system, the applicant stated the following:

> Fluid-containing portions of the boiler feed console pump foam suppression systems are included with miscellaneous systems in-scope pursuant to 10 CFR 54.4(a)(2) and are subject to an AMR. The AMR results for the fluid-containing portions of the system are shown in LRA Table 3.3.2-19-20-IP3. Based on discussion in the SER for IP3 dated March 6, 1979, the boiler feed console pump foam suppression system is considered as meeting the scoping requirements of 10 CFR 54.4(a)(3), in addition to 10 CFR 54.4(a)(2). The AMR results in LRA Table 3.3.2-11-IP3 are applicable to the portions of the boiler feed console pump foam suppression system normally containing air.

Based on its review, the staff finds the applicant's response acceptable because it clarified that the boiler feed console pump foam suppression systems are included in the scope of license renewal with miscellaneous systems in accordance with 10 CFR 54.4(a)(2) and are subject to an AMR.

Based on its review, the staff finds the applicant's response to RAI 2.3B.3.11-1 acceptable. The staff's concern described in RAI 2.3B.3.11-1 is resolved.

In RAI 2.3B.3.11-2, dated October 24, 2007, the staff stated that Section 3.1.8 of the fire protection SER for IP3, dated March 6, 1979, discusses dry-pipe, pre-action sprinkler systems for all cable trays in the electrical tunnels, electrical penetration areas, and cable trays in the motor control center areas. LRA Section 2.3.3.11 does not indicate that the dry-pipe pre-action sprinkler systems are within the scope of license renewal and subject to an AMR. The staff requested that the applicant verify whether the dry-pipe pre-action sprinkler systems for all cable trays in the electrical tunnels, electrical penetration areas, and cable trays in the motor control center areas are within the scope of license renewal, as required by 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 asked the applicant to justify their exclusion.

In its response, dated November 16, 2007, the applicant stated that the dry-pipe, pre-action sprinkler systems for all cable trays in the electrical tunnels, electrical penetration areas, and cable trays in the motor control center areas are within the scope of license renewal and subject to an AMR. License renewal drawing LRA-9321-40913-001-0 shows the electrical tunnel dry pipe pre-action sprinkler systems 8, 8A, 9, and 9A at coordinates G6. The electrical tunnel sprinkler systems cover areas in the electrical penetration area and cable trays in the motor control center areas, in addition to the cable trays in the electrical tunnels. The absence of boundary flags where the highlighted piping enters the text box indicates that the portion of the system described in the text box is within scope and subject to an AMR.

Based on its review, the staff finds the response to RAI 2.3B.3.11-2 acceptable because the applicant identified the dry-pipe, pre-action sprinkler systems for all cable trays in the electrical tunnels, electrical penetration areas, and cable trays in the motor control center areas as within the scope of license renewal and subject to an AMR. Therefore, the staff concludes that the applicant correctly identified these dry-pipe, pre-action sprinkler systems and the associated components as within the scope of license renewal and subject to an AMR. The staff's concern described in RAI 2.3B.3.11-2 is resolved.

In RAI 2.3B.3.11-3, dated October 24, 2007, the staff stated that Section 5.9.1 of the March 6, 1979, fire protection SER for IP3 discusses automatic deluge foam suppression systems for various areas in the turbine building. LRA Section 2.3.3.11 does not indicate that the foam suppression systems are within the scope of the license renewal and subject to an AMR. The staff requested that the applicant verify whether the foam suppression systems for various areas in the turbine building are within the scope of license renewal, as required by 10 CFR 54.4(a), and subject to an AMR, in accordance with 10 CFR 54.21(a)(1). If the systems are excluded from the scope of license renewal and are not subject to an AMR, the staff asked the applicant to justify their exclusion.

In its response, dated November 16, 2007, the applicant stated that the fluid-containing portions of the foam suppression systems for various areas in the turbine building are included with miscellaneous systems, in accordance with 10 CFR 54.4(a)(2), and are subject to an AMR. LRA Table 3.3.2-19-20-IP3 summarizes the AMR results for the fluid-containing portions of the systems. Based on the discussion in the March 6, 1979, fire protection SER for IP3, the foam suppression systems for various areas in the turbine building meet the scoping requirements of 10 CFR 54.4(a)(3), in addition to 10 CFR 54.4(a)(2). The applicant further identified the system components that are subject to an AMR, in accordance with 10 CFR 54.21(a)(1). The applicant indicated that LRA Table 3.3.2-11-IP3 summarizes the AMR results.

Based on its review, the staff finds the applicant's response to RAI 2.3B.3.11-3 acceptable because fluid-containing portions of the foam systems for various areas in the turbine building were identified as being within the scope of license renewal and subject to an AMR. The AMR results are summarized in LRA Table 3.3.2-20-IP3.

In RAI 2.3B.3.11-4, dated October 24, 2007, the staff stated that Section 5.11.1 of the March 6, 1979, fire protection SER for IP3 discusses wet pipe automatic sprinklers in the diesel generator building sump area beneath each diesel engine and on the diesel day tank. On license renewal drawing LRA-9321-40913-0, at coordinate E3, the wet pipe automatic sprinkler system does not appear to be within the scope of the license renewal and subject to an AMR (i.e., the box surrounding the sprinklers in question is not highlighted). The staff requested that the applicant verify whether the wet pipe sprinkler system designed to protect the diesel generator building sump area and diesel day tank is within the scope of license renewal, as required by 10 CFR 54.4(a), and subject to an AMR, in accordance with 10 CFR 54.21(a)(1). If the system is excluded from the scope of license renewal and is not subject to an AMR, the staff asked the applicant to justify its exclusion.

In its response, dated November 16, 2007, the applicant stated that the IP3 wet pipe automatic sprinklers in the diesel generator building sump area beneath each diesel engine and on the diesel day tanks are in scope and subject to an AMR, as shown on license renewal drawing LRA-9321-40913-001-0, coordinate E3. The absence of boundary flags where the highlighted piping enters the text box indicates that the portion of the system described in the text box is within the scope of license renewal and subject to an AMR, along with the highlighted components on the drawing.

Based on its review, the staff finds the response to RAI 2.3B.3.11-4 acceptable because the applicant identified wet pipe automatic sprinklers in the diesel generator building sump area beneath each diesel engine and on the diesel day tank as within the scope of license renewal and subject to an AMR. Further, the applicant clarified that the absence of boundary flags where the highlighted piping enters the text box indicates that the portion of the system described in the text box is within the scope of license renewal and subject to an AMR, along with the highlighted components on license renewal drawing LRA-9321-40913-001-0. Therefore, the staff concludes that the applicant correctly identified the wet pipe automatic sprinklers in question as within the scope of license renewal and subject to an AMR. The staff's concern described in RAI 2.3B.3.11-4 is resolved.

In RAI 2.3B.3.11-5, dated October 24, 2007, the staff stated that Section 5.13.1 of the March 6, 1979, fire protection SER for IP3 discusses the charcoal filter manual water spray system. LRA Section 2.3.3.11 does not indicate that the manual water spray system and its associated components are within the scope of the license renewal and subject to an AMR. The staff requested that the applicant verify whether the charcoal filter manual water spray system and its associated components are within the scope of license renewal, as required by 10 CFR 54.4(a), and subject to an AMR, in accordance with 10 CFR 54.21(a)(1). If the system is excluded from the scope of license renewal and is not subject to an AMR, the staff asked the applicant to justify its exclusion.

In its response, dated November 16, 2007, the applicant stated that the IP3 charcoal filter manual water spray system is in scope, as shown on license renewal drawing LRA-9321-40913-001-0 at coordinates H8. The absence of boundary flags where the highlighted piping enters the text box indicates that the portion of the system described in the text box is in scope and subject to an AMR, along with the highlighted components on the drawing. License renewal drawing LRA-9321-40913-001-0 continues to an equipment arrangement drawing which is not available as a license renewal drawing.

Based on its review, the staff finds the response to RAI 2.3B.3.11-5 acceptable because the applicant identified the charcoal filter manual water spray system in question as within the scope of license renewal and subject to an AMR. Further, the applicant clarified that the absence of boundary flags where the highlighted piping enters the text box indicates that the portion of the system described in the text box is within the scope of license renewal and subject to an AMR, along with the highlighted components on license renewal drawing LRA-9321-40913-001-0.

In RAI 2.3B.3.11-6, dated October 24, 2007, the staff stated that Section 5.15.1 of the March 6, 1979, fire protection SER for IP3 discusses automatic water spray systems for oil-filled transformers located adjacent to the control building. LRA Section 2.3.3.11 does not indicate that the automatic water spray systems and their associated components are within the scope of license renewal and subject to an AMR. The staff requested that the applicant verify whether the automatic water spray systems for oil-filled transformers are within the scope of license renewal, as required by 10 CFR 54.4(a), and subject to an AMR, in accordance with 10 CFR 54.21(a)(1). If the systems are excluded from the scope of license renewal and are not subject to an AMR, the staff asked the applicant to justify their exclusion.

In its response, dated November 16, 2007, the applicant stated that it initially determined that the automatic water spray systems and their associated components for the oil-filled transformers located adjacent to the control building did not have a license renewal intended function. The applicant believed that they were only required to protect the transformers, satisfying requirements of the plant insurance carrier. However, the spray systems provide for defense in depth, in addition to the installed 3-hour-rated fire barriers between the control building and the transformer yard, and are considered in scope and subject to an AMR. LRA Table 2.3.3-11-IP3 includes the applicable component types subject to an AMR, and LRA Table 3.3.2-11-IP3 provides the AMR results.

Based on its review, the staff finds the response to RAI 2.3B.3.11-6 acceptable because the applicant concluded that the automatic spray system for the oil-filled transformer performs a defense-in-depth function and, therefore, is within the scope of license renewal and subject to an AMR. The staff confirmed that LRA Table 3.3.2-11-IP3 provides the AMR results. Therefore, the staff finds that the applicant correctly identified the automatic water spray systems and their associated components for the oil-filled transformers as within the scope of license renewal and subject to an AMR. The staff's concern described in RAI 2.3B.3.11-6 is resolved.

2.3B.3.11.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the fire protection - water system 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).

2.3B.3.12 IP3 Fire Protection—Carbon Dioxide, Halon, and RCP Oil Collection Systems

2.3B.3.12.1 Summary of Technical Information in the Application

LRA Section 2.3.3.12 describes the fire protection—CO_2, Halon, and RCP oil collection system, which is listed under the following system codes:

- CO_2 system: system code CO2
- Halon: system code HAL
- RCP oil collection components: system code RCS

The CO_2 system provides fire protection and supplies CO_2 gas to purge the main generator. The CO_2 fire protection system has two 10-ton-capacity, low-pressure tanks, a distribution header, piping, and valves. An automatic total-flooding CO_2 fire suppression system protects the 480-V switchgear room, cable spreading room, diesel generator rooms, and the turbine generator exciter enclosure. A local application CO_2 fire suppression system protects the turbine building, including the main boiler FW pumps, turbine governor, MS and reheat valves, and generator bearings. Before maintenance work on the main generator, the hydrogen gas must be evacuated from the system. Inert CO_2 gas from a CO_2 gas-vaporizing system purges the generator. The IP2 CO_2 gas-vaporizing system also may operate through a supply line from the IP1 intake structure area.

The Halon 1301 system suppresses fires in the administration/service building technical support center/computer room, in the Appendix R diesel enclosure, and in the meteorological building. The Halon system does not protect any safety-related plant equipment. Protection of the Appendix R diesel enclosure from fire is not a required function under Appendix R. For IP3, the Halon 1301 system has no intended functions under 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), or 10 CFR 54.4(a)(3).

The RCP oil collection system is designed, engineered, and installed so an RCP lube oil system failure will not lead to fire during normal or DBA conditions or impact any safety-related system capability during a safe-shutdown earthquake. The collection system can collect lube oil from all pressurized and unpressurized potential leakage sites in the RCP lube oil systems and drain it to a vented closed tank that can hold the required lube oil system inventory. A flame arrester in each tank vent prevents fire flashback. The collection system consists of leakproof enclosures or pans under oil-bearing components to contain leaks.

The fire protection—CO_2 and RCP oil collection systems have no intended functions under 10 CFR 54.4(a)(1).

The scoping and screening methodology identified the following RCP oil collection system intended function, in accordance with 10 CFR 54.4(a)(2):

- Maintain integrity of nonsafety-related components such that no physical interaction with safety-related components could prevent satisfactory accomplishment of a safety function.

The scoping and screening methodology also identified the following CO_2 and RCP oil collection systems intended functions, in accordance with 10 CFR 54.4(a)(3):

- Provide automatic and manual CO_2 flooding for areas of the plant that (1) contain safety-related equipment or (2) pose significant hazards to plant areas containing safety-related equipment (10 CFR 50.48) or both.

- Provide each RCP with an oil collection system that is designed to contain and direct the oil to remote storage containers in the event of an oil leak.

LRA Table 2.3.3-12-IP3 identifies fire protection—CO_2 and RCP oil collection systems component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.12.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.11, UFSAR Sections 9.6.2.3 and 9.6.2.4, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

The staff also reviewed the following IP3 fire protection CLB documents listed in the IP3 Operating License Condition 2.H: NRC fire protection SERs for IP3 dated September 21, 1973; March 6, 1979; May 2, 1980; November 18, 1982; December 30, 1982; February 2, 1984; April 16, 1984; January 7, 1987; September 9, 1988; October 21, 1991; April 20, 1994; and January 5, 1995.

The staff also reviewed IP3 commitments associated with 10 CFR 50.48 (i.e., an approved fire protection program), using its commitment responses to BTP APCSB 9.5-1 and BTP APCSB 9.5-1, Appendix A.

During its review of LRA Section 2.3.3.12, the staff identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

In RAI 2.3B.3.12-1, dated October 24, 2007, the staff asked the applicant to explain why license renewal drawing LRA-9321-24403-0 indicated that the following fire protection system components were not subject to an AMR (i.e., they are not highlighted in brown):

- Appendix R diesel generator Halon 1301 system
- technical support center/plant computer Halon system
- IP3 record room vault Halon 1301 system

The staff requested that the applicant verify whether the above components are within the scope of license renewal, as required by 10 CFR 54.4(a), and subject to an AMR, in accordance with 10 CFR 54.21(a)(1). If these components are excluded from the scope of license renewal and are not subject to an AMR, the staff asked the applicant to justify their exclusion.

In its response, dated November 16, 2007, the applicant addressed each system individually. For the Appendix R diesel generator Halon 1301 system, the applicant stated that the Appendix R diesel generator is located in a standalone structure separated from other plant structures and equipment. The applicant further explained that the technical support center/plant computer and the record room vault are located in an administration building attached to the turbine building. The applicant added that a sprinkler system had replaced the IP3 record room vault Halon 1301 system.

The applicant stated that the areas referenced in the RAI response do not contain systems or components required for safe shutdown of the plant, do not provide an exposure hazard to any building or area required for safe shutdown, and are not located in safety-related areas. The applicable IP3 fire protection SER, dated March 6, 1979, credits no fire suppression systems for these areas. The Halon systems are not required for compliance with 10 CFR 50.48. The fire protection SER does not stipulate the addition of suppression systems for the Appendix R diesel generator, technical support center/plant computer, or the IP3 record room vault.

Based on its review, the staff finds the applicant's response to RAI 2.3B.3.12-1 acceptable. The applicant does not credit the Halon 1301 systems for the Appendix R diesel generator room, technical support center/plant computer room, and record room vault toward meeting the requirements of Appendix R to 10 CFR Part 50 for achieving safe shutdown in the event of a fire. Although the IP3 March 6, 1979, fire protection SER addresses the Halon 1301 systems for the Appendix R diesel generator room, technical support center/plant computer room, and record room vault, NRC fire protection regulations do not require these systems. The Appendix R diesel generator room, technical support center/plant computer room, and record room vault are not safety related and cannot affect safety-related equipment by spatial interaction. Furthermore, they are not required for safe shutdown. Therefore, they have no intended function under 10 CFR 54.4(a)(2). In addition, the staff reviewed commitments made by the applicant to satisfy BTP APCSB 9.5-1, Appendix A, which discusses Halon 1301 systems and found no intended function associated with 10 CFR 54.4(a)(2). Therefore, the staff finds that the applicant correctly excluded the Halon 1301 systems for the Appendix R diesel generator room, technical support center/plant computer room, and record room vault from the scope of license renewal and an AMR. The staff's concern described in RAI 2.3B.3.12-1 is resolved.

2.3B.3.12.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the fire protection CO_2, Halon, and RCP oil collection system 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).

2.3B.3.13 IP3 Fuel Oil Subsystems

2.3B.3.13.1 Summary of Technical Information in the Application

LRA Section 2.3.3.13 describes the IP3 fuel oil subsystems, which include the IP3 EDGs, the IP3 fire protection diesel engines, and the IP3 Appendix R diesel generator.

Each diesel fuel oil storage and transfer system supplying fuel to the EDGs has its own fuel oil day tank and an underground storage tank. The day tanks are within the diesel generator buildings. An engine-driven fuel oil pump supplies the fuel from the day tank to the engine. The day tank fills automatically during engine operation from its dedicated underground storage tank, which is adjacent to the diesel generator building. Each underground storage tank has a motor-driven transfer pump to transfer fuel to the day tank.

Independent diesel fuel oil storage and transfer systems supply fuel to the IP2 and IP3 fire protection diesel engines. The IP3 fuel oil storage tank and components are located in the IP3 fire protection pump house.

An independent diesel fuel oil storage and transfer system supplies fuel to the IP3 Appendix R diesel generator, which has its own fuel oil day tank and underground storage tank. The day tank supplies fuel directly to the engine. A transfer pump fills the fuel oil day tank automatically from its storage tank during engine operation.

The fuel oil subsystems contain safety-related components relied on to remain functional during and following DBEs. They also contain nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the fuel oil subsystems perform functions that support fire protection and SBO.

LRA Table 2.3.3-13-IP3 identifies fuel oil subsystem component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.13.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.13; UFSAR Sections 1.3.1, 8.2, and 16.1.3; and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.3.13, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The discussion of the staff's RAIs in SER Section 2.3B.3 details the disposition of RAI 2.3B.3.13-1, dated February 13, 2008.

2.3B.3.13.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI response, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has appropriately identified the fuel oil system components within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, in accordance with 10 CFR 54.21(a)(1).

2.3B.3.14 IP3 Emergency Diesel Generator System

2.3B.3.14.1 Summary of Technical Information in the Application

LRA Section 2.3.3.14 describes the EDG system, which supplies emergency shutdown power upon loss of all other alternating current auxiliary power. The system consists of three EDG sets, each with a diesel engine coupled to a 480-V generator. Each emergency diesel is started automatically by two redundant air motors and has an air storage tank and compressor system, its own starting air subsystem, fuel oil subsystem, intake air subsystem, exhaust subsystem, lube oil subsystem, and jacket water cooling subsystem. The EDG system also has ventilation equipment for the diesel generator building.

The EDG system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure could prevent the satisfactory accomplishment of a safety-related function. In addition, the EDG system performs functions that support fire protection.

The HVAC component parts of this system code are reviewed with HVAC systems (LRA Section 2.3.3.8). Fuel oil subsystem components are evaluated with fuel oil (LRA Section 2.3.3.13). Nonsafety-related components not evaluated with other systems and whose failure could prevent satisfactory accomplishment of safety functions are evaluated with miscellaneous systems (LRA Section 2.3.3.19). Remaining components are evaluated in LRA Section 2.3.3.14.

LRA Tables 2.3.3-14-IP3, 2.3.3-19-16-IP3, and 2.3.3-19-17-IP3 identify EDG system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.14.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.14, UFSAR Sections 8.2 and 16.1.3, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.3.14, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3B.3.14-1, dated December 7, 2007, the staff noted that a license renewal drawing for the IP3 jacket water to EDGs identified that the jacket water pumps for diesel engine Nos. 31, 32, and 33 are not subject to an AMR, in accordance with 10 CFR 54.21(a), because they are not long-lived components. The staff noted that SRP-LR, Table 2.3-2, provides examples of passive, long-lived components, such as diesel engine jacket water skid-mounted equipment. To complete its review, the staff requested that the applicant confirm that the jacket water pumps are short-lived components and describe its method for periodic replacement of these components.

In its response, dated January 4, 2008, the applicant stated that IP3 EDG maintenance procedures specify that the jacket water pumps in question are scheduled for replacement every 16 years, in accordance with station maintenance procedures, and, therefore, they are not subject to an AMR.

Based on its review, the staff finds the response to RAI 2.3B.3.14-1 acceptable because the applicant adequately explained that the practice of replacing the jacket water pumps meets the intent of 10 CFR 54.21(a)(1)(ii) for short-lived components and that the maintenance procedures control the pumps' periodic replacement. Therefore, the staff agrees that the jacket water pumps are not subject to an AMR. The staff's concern described in RAI 2.3B.3.14-1 is resolved.

In RAI 2.3A.3.14-2, dated December 7, 2007, the staff noted that license renewal drawings for the EDG jacket water cooling systems and EDG fuel oil systems for IP2 and IP3 label multiple "flexible conn [connections]" as not long-lived components. By letter dated January 4, 2008, the applicant responded to the staff's RAI. SER Section 2.3A.3.14 documents the RAI, the applicant's response, and the staff's evaluation.

The discussion of the staff's RAIs in SER Section 2.3B.3 details the disposition of RAI 2.3B.3.14-2, dated February 13, 2008.

2.3B.3.14.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has appropriately identified the EDG system 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).

2.3B.3.15 IP3 Security Generator System

2.3B.3.15.1 Summary of Technical Information in the Application

LRA Section 2.3.3.15 describes the security propane generator system, which supplies power for the security lighting system and other security functions. The applicant credits a portion of this security lighting under Appendix R, Section III.J (emergency lighting), to illuminate ingress and egress to the Appendix R diesel generator, main and backup SW pumps, CST, and RWST.

The security propane generator system performs functions that support fire protection.

LRA Table 2.3.3-15-IP3 identifies security propane generator system component types within the scope of license renewal and subject to an AMR as well as their intended functions.

2.3B.3.15.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.15 and UFSAR Section 9.6.2.6 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3B.3.15.3 Conclusion

The staff reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the security propane generator system 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).

2.3B.3.16 IP3 Appendix R Diesel Generator System

2.3B.3.16.1 Summary of Technical Information in the Application

LRA Section 2.3.3.16 describes the Appendix R diesel generator system, which supplies power to selected equipment and power supplies relied on in Appendix R and SBO events. The Appendix R diesel generator complies with SBO requirements and can supply sufficient power for safe-shutdown loads through the 6.9-kV distribution and the emergency 480-V buses and motor control centers or the turbine building switchgear and motor control centers. Located in a separate structure in the yard area, the Appendix R diesel generator installation is a self-contained package that operates upon a complete loss of power and includes a starting air compressor, batteries, battery charger, jacket water heater, lube oil heater, fuel oil pump and lube oil pumps, and necessary filters and strainers.

The Appendix R diesel generator system performs functions that support fire protection and SBO.

Fuel oil subsystem components are reviewed with fuel oil (LRA Section 2.3.3.13). Ventilation for the Appendix R diesel generator system is reviewed with HVAC systems (LRA Section 2.3.3.8). Remaining components are evaluated in LRA Section 2.3.3.16.

LRA Table 2.3.3-16-IP3 identifies Appendix R diesel generator system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.16.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.16, UFSAR Sections 8.1.1 and 8.2.3, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3B.3.16.3 Conclusion

The staff reviewed the LRA, UFSAR, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the Appendix R diesel generator system 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).

2.3B.3.17 IP3 City Water System

2.3B.3.17.1 Summary of Technical Information in the Application

LRA Section 2.3.3.17 describes the city water system, which supplies water to various components throughout the plant. The city water supply was installed originally for IP1, but now has functions for all three units. The IP2 city water description includes the city water tank and many of the shared site components. This system includes only the IP3 components. City water is used for a variety of purposes throughout IP3, such as supplying water to fire protection systems, to equipment for makeup or cooling, and to sanitary and potable facilities (e.g., emergency showers, eye wash stations, hose connections, sinks, water coolers, water heaters, and lavatories). The system also supplies a backup, but not a safety-grade, source of water to the AFW pumps and can supply makeup to the spent fuel pit.

The city water system contains nonsafety-related components whose failure could potentially prevent the satisfactory accomplishment of a safety-related function. In addition, the city water makeup performs functions that support fire protection.

Components of the city water system that provide water to the AFW system are reviewed with the AFW systems (LRA Section 2.3.4.3).

LRA Tables 2.3.3-17-IP3 and 2.3.3-19-13 identify city water system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.17.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.17, UFSAR Sections 6.1.1 and 10.3.1, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.3.17, the staff identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

In RAI 2.3B.3.17-1, dated December 7, 2007, the staff noted that the LRA states that the IP3 city water system has the intended function under 10 CFR 54.4(a)(3) of providing water to the fire protection tanks. The staff further noted that the applicant did not highlight on a license renewal drawing for the city water system a portion of the city water system piping upstream of the eight isolation valves to fire water storage tanks 1 and 2 to indicate that it is within the scope of license renewal. This piping connects to the 16-inch water main from the Village of Buchanan and provides makeup water for the fire water supply function. The staff asked the applicant to explain why it considered all of the city water system piping from the 16-inch water main for the Village of Buchanan to the fire water storage tanks to be outside the scope of license renewal under 10 CFR 54.4(a)(3) and not subject to an AMR.

In its response, dated January 4, 2008, the applicant stated that the 16-inch water main from the Village of Buchanan is a source of makeup water for the city water system. The applicant explained that city water is the normal source of makeup water to the two fire water storage tanks; however, the city water source is not required to support any fire scenarios or Appendix R events, since each of the storage tanks has a sufficient reserve for fire fighting, without makeup, available to handle all fire scenarios. Therefore, although the city water system can provide a water supply to the fire water tanks, it is not a license renewal intended function, since makeup is not required for compliance with 10 CFR 50.48 fire scenarios or Appendix R events. As a result, the applicant changed LRA Section 2.3.3.17, for IP3, to delete the intended function bullet item, “provide water supply to the fire protection tanks (10 CFR 50.48),” as a 10 CFR 54.4(a)(3) function.

Based on its review, the staff finds the applicant’s response to RAI 2.3B.3.17-1 acceptable because it adequately explained that, although city water is the normal source of makeup water to the two fire water storage tanks, the source is not required to support any fire scenarios or Appendix R events. Each of the storage tanks has a sufficient reserve for firefighting that can handle all fire scenarios without the need for continued makeup. Since makeup is not required for 10 CFR 50.48 fire scenarios or Appendix R events, the applicant has changed LRA Section 2.3.3.17, for IP3, to delete the intended function bullet item, “provide water supply to the fire protection tanks (10 CFR 50.48),” as a 10 CFR 54.4(a)(3) function. The staff’s concern described in RAI 2.3B.3.17-1 is resolved.

In RAI 2.3B.3.17-2, dated December 7, 2007, the staff noted that the LRA states that the IP3 city water system has no intended functions, in accordance with 10 CFR 54.4(a)(1). However, the staff noted that, on a license renewal drawing for the city water system under “General Notes,” the applicant stated under the heading “Class I Piping,” “(1) above ground city water make-up to closed cooling water system—expansion tank in control room and EDG jacket water expansion tank,” and “(2) city water from Unit 1 tie into AFW pumps suction.” The staff also noted that under the heading “Class III Piping,” the LRA states, “(1) above ground city water make-up to closed cooling water system—head tank in turbine building,” and “(2) above ground city water supply to nuclear services.”

In addition, the staff found that a license renewal drawing for the condensate and boiler feed pump suction system shows a small portion of the city water system piping. This portion of city water system piping is highlighted in purple, indicating that it is within the scope of license renewal and subject to an AMR. The drawing identifies this portion of city water system piping as Class I. By definition, all Class I and Class III piping should have intended functions under 10 CFR 54.4(a)(1). The staff requested that the applicant address the following:

(a) Explain why the Class I and Class III city water system piping on the two drawings do not have an intended function, in accordance with 10 CFR 54.4(a)(1).

(b) Explain why the city water piping up to the closed cooling water system expansion tank, EDG jacket water expansion tank, closed cooling water system head tank, and nuclear services on the one city water system license renewal drawing is not highlighted in purple, indicating that it is within the scope of license renewal and subject to an AMR.

(c) Explain why the city water system piping that continues from one city water license renewal drawing onto another drawing for supplying the 40-gallon EDG jacket water expansion tanks is also not highlighted in purple, indicating that it is within the scope of license renewal and subject to an AMR.

In its response, dated January 4, 2008, the applicant stated the following:

> (a) Class I and Class III refer to seismic classification; not to ASME safety class, and that Class I components include safety-related equipment. The applicant further stated that Class I SSCs also include components that do not perform a safety function. The applicant explained Class III is the designation for SSCs which are not directly related to reactor operation and containment, and which do not have to maintain structural integrity during or following an SSE. Further, when defining the city water system components required to support a 10 CFR 54.4(a)(1) system intended functions for license renewal, the seismic classification boundaries were not used, since they do not accurately reflect the portions of the system required to meet system intended functions. Finally, the applicant explained that all components needed to accomplish system intended functions were included within scope regardless of the class breaks on the drawings.
>
> (b) The license renewal drawings only highlight portions of systems within scope and subject to an aging management review for 10 CFR 54.4(a)(1) or (a)(3). The city water piping up to the closed cooling water system expansion tank, EDG jacket water expansion tank, closed cooling water system head tank, and nuclear services on the city water license renewal drawing is not required to meet any system intended functions described in 10 CFR 54.4(a)(1) or (a)(3); therefore, the piping is not highlighted. However, this piping and valves are within scope for 10 CFR 54.4(a)(2) due to the potential for spatial interaction and are included in LRA tables for components subject to an AMR.
>
> (c) The LRA drawings only reflect portions of systems in scope and subject to aging management review for 10 CFR 54.4(a)(1) or (a)(3). The city water piping up to the diesel generator jacket water expansion tank on drawings LRA-9321-20343-001 and 9321-H-20283 is not required to meet any system intended functions described in 10 CFR 54.4(a)(1) or (a)(3) and therefore is not highlighted. However, this piping and valves are in scope for 10 CFR 54.4(a)(2) due to the potential for spatial interaction. They are included in LRA Tables 2.3.3-19-13-1P3 and 3.3.2-19-13-1P3.

City water is the source of makeup water to the 40-gallon diesel generator jacket water expansion tanks. Makeup water is not required for the EDGs to perform their intended function.

Based on its review, the staff finds the response to RAI 2.3B.3.17-2(a) acceptable because the applicant adequately explained that Class I and Class III on the license renewal drawing refer to seismic classification, rather than ASME safety class. Class I SSCs at IP2 and IP3 include components that do not perform a safety function. At IP2 and IP3, Class III is the designation for SSCs that are not directly related to reactor operation and containment and that do not have to maintain structural integrity during or following a safe-shutdown earthquake. The applicant did not use the seismic classification boundaries when defining the city water system components that are required to comply with 10 CFR 54.4(a)(1) system intended functions for license renewal, since they do not accurately reflect the portions of the system required to meet system intended functions. The applicant included all components needed to accomplish system intended functions within the scope of license renewal, regardless of the seismic class breaks on the drawings. The staff's concern described in RAI 2.3B.3.17-2(a) is resolved.

Based on its review, the staff finds the applicant's response to RAI 2.3B.3.17-2(b) acceptable because it adequately explained that the license renewal drawings reflect only the portions of systems within scope and subject to an AMR, in accordance with 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3). The city water piping up to the closed cooling water system expansion tank, EDG jacket water expansion tank, closed cooling water system head tank, and nuclear services, as depicted on the city water license renewal drawing, is not required to meet any system intended functions under 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3); therefore, it was not highlighted. Although not highlighted, the applicant has included the piping and valves within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2), because of the potential for spatial interaction. The applicant also included the piping and valves in city water LRA tables for components subject to an AMR. The staff's concern described in RAI 2.3B.3.17-2(b) is resolved.

Based on its review, the staff finds the applicant's response to RAI 2.3B.3.17-2(c) acceptable because it adequately explained that the license renewal drawings reflect only the portions of systems within the scope of license renewal and subject to an AMR, under 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3). The city water piping up to the EDG jacket water expansion tank is not required to meet any system intended functions, in accordance with 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(3); therefore, it was not highlighted. Although not highlighted, the applicant considered the piping and valves to be within scope, in accordance with 10 CFR 54.4(a)(2), because of the potential for spatial interaction. The applicant included the piping and valves in city water LRA tables for components subject to an AMR. City water, as a makeup water source to the EDG jacket water expansion tanks, is not required for the EDGs to perform their intended function. The staff's concern described in RAI 2.3B.3.17-2(c) is resolved.

2.3B.3.17.3 Conclusion

The staff reviewed the LRA, UFSAR, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has appropriately identified the city water system 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).

2.3B.3.18 IP3 Plant Drains

2.3B.3.18.1 Summary of Technical Information in the Application

LRA Section 2.3.3.18 describes the plant drains, which are passive fire protection features required for adequate protection of safety-related equipment from water damage in areas with fixed suppression systems. Plant drain components also prevent drain systems in areas with combustible materials from spreading fires into other areas of the plant. Some plant drains protect safety-related equipment from flooding effects.

Plant drain components are included in various systems, but grouped for this evaluation. SRP-LR Section 2.1.3.1 indicates that it is appropriate to group similar components from various plant systems into one consolidated review.

To prevent local flooding, areas with automatically operated fire protection have either gravity or pump drains to handle the maximum quantity of spray water. Plant drains protect safety-related equipment in the diesel generator rooms, electrical tunnels, PAB, and auxiliary feed pump room from the effects of Class III component failure. Either floor drains remove fire suppression water adequately or the water flows through other passages to protect safety-related equipment. When safety-related equipment may be lost as a result of inadvertent actuation of a fire system, redundant systems are available for safe shutdown.

The floor drains, fire water, and liquid waste disposal systems include plant drain components. Other sections do not address the waste disposal and liquid waste disposal systems. The floor drains system is not required for regulated events. Other systems provide drainage for flooding protection.

The liquid waste disposal system collects and processes liquid wastes from throughout the plant, including wastes from equipment drains, radioactive chemical laboratory drains, decontamination drains, demineralizer regeneration, and floor drains. The system also collects and transfers liquid drained from the RCS directly to the CVCS for processing. The system includes piping, valves, pumps, collection tanks, instruments, and controls. The system includes several containment penetrations and accompanying isolation components.

SER Section 2.3B.3.19 describes the floor drains system. SER Section 2.3B.3.11 describes the fire water system.

The plant drains system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the plant drains system performs functions that support fire protection.

A small number of liquid waste disposal system components are reviewed with the safety injection systems (LRA Section 2.3.2.4) and the primary water makeup systems (LRA Section 2.3.3.7).

LRA Tables 2.3.3-18-IP3 and 2.3.3-19-33-IP3 identify plant drains system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.18.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.18 and UFSAR Sections 9.6.2.3, 11.1, and 16.1.3 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.3.18, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The discussion of the staff's RAIs in SER Section 2.3B.3 details the disposition of RAI 2.3B.3.18-1, dated February 13, 2008.

2.3B.3.18.3 Conclusion

The staff reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has appropriately identified the plant drains system 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).

2.3B.3.19 IP3 Miscellaneous Systems in Scope for 10 CFR 54.4(a)(2)

2.3B.3.19.1 Summary of Technical Information in the Application

In LRA Section 2.3.3.19, the applicant described those systems that it included within the scope of license renewal because of their potential for physical interactions with safety-related components, as required by 10 CFR 54.4(a)(2). In this section, the applicant also described the components in these systems that are subject to an AMR. LRA Table 2.3.3-19-A-IP3 lists all of these systems and the LRA section in which the applicant evaluated these systems. LRA Section 2.3.3.19 describes in detail those systems, which are listed below, that do not have correlating LRA sections:

- ammonia/morpholine addition
- boron and layup chemical addition
- CL
- CW
- extraction steam
- floor drains
- gaseous waste disposal
- hydrazine addition
- heater drain/moisture separator drain/vent

- instrument air closed cooling
- lube oil
- low-pressure steam dump
- main turbine generator
- nuclear equipment drains
- process radiation monitoring
- primary plant sampling
- river water service
- main generator seal oil
- secondary plant sampling
- turbine hall closed cooling
- vapor containment hydrogen analyzer
- hydrogen (added by applicant by letter dated March 12, 2008)

Also in LRA Section 2.3.3.19, the applicant identified the following IP3 systems that it did not review under 10 CFR 54.4(a)(2) for spatial interaction because the applicant included all of the system's passive mechanical components under either 10 CFR 54.4(a)(1), another function of 10 CFR 54.4(a)(2), or 10 CFR 54.4(a)(3):

- AFW
- control building HVAC
- CCW
- control rod drive
- control room HVAC
- engineered safeguards initiation logic
- isolation valve seal water
- RHR
- reactor protection and control
- SG
- SG level control
- security propane generator

The following are brief descriptions of IP3 systems that are included within the scope of license renewal and subject to an AMR, based only on the criterion of 10 CFR 54.4(a)(2).

Ammonia/Morpholine Addition System. The purpose of the ammonia/morpholine addition system is to provide ammonia or morpholine for pH control for the condensate system. LRA Table 2.3.3-19-1-IP3 identifies ammonia/morpholine addition system component types within the scope of license renewal and subject to an AMR as well as their intended functions.

Boron and Layup Chemical Addition System. The boron and layup chemical addition system supplies chemicals to the SGs for chemistry control, even during periods of wet layup. Components in the boron and layup chemical addition system that support the AFW system pressure boundary are evaluated with the AFW systems (LRA Section 2.3.4.3). LRA Table 2.3.3-19-3-IP3 identifies boron and layup chemical addition system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Chlorination System. The chlorination system supplies sodium hypochlorite to limit microorganism fouling in the intake bays and river water systems. LRA Table 2.3.3-19-5-IP3 identifies chlorination system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Circulating Water System. The CW system supplies the condenser with Hudson River water to cool the steam exiting the low-pressure turbines. LRA Table 2.3.3-19-12-IP3 identifies CW system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Extraction Steam System. The extraction steam system utilizes steam to preheat feedwater. LRA Table 2.3.3-19-18-IP3 identifies extraction steam system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Floor Drains System. The floor drains system removes any water collected in the nonradioactive floor drains in the turbine building, intake structure, and diesel generator building. LRA Table 2.3.3-19-19-IP3 identifies floor drains system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Gaseous Waste Disposal System. The gaseous waste disposal system collects, compresses, stores, samples, and releases gaseous waste from the primary and auxiliary systems. LRA Table 2.3.3-19-25-IP3 identifies gaseous waste disposal system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Hydrazine Addition System. The hydrazine addition system injects hydrazine into the secondary system for oxygen control. LRA Table 2.3.3-19-26-IP3 identifies hydrazine addition system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Heater Drain/Moisture Separator Drain/Vent System. The heater drain/moisture separator drain/vent system collects and transfers FW heater and moisture separator-reheater drainage to the suction of the main boiler FW pumps. LRA Table 2.3.3-19-27-IP3 identifies heater drain/moisture separator drains/vents system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Instrument Air Closed Cooling System. The instrument air closed-cooling system is a separate closed-loop cooling water system. This system supplies cooling water to the instrument air compressors and aftercoolers and rejects heat to the SW system. LRA Table 2.3.3-19-30-IP3 identifies instrument air closed-cooling system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Lube Oil System. The lube oil system supplies oil for lubrication and control of the main turbine and the main boiler FW pumps and turbines. The lube oil system includes components that make up the main turbine controls. LRA Table 2.3.3-19-31-IP3 identifies lube oil system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Low-Pressure Steam Dump System. The low-pressure steam dump system prevents turbine overspeed by discharging steam from the high-pressure turbine exhaust to the condenser upon turbine trip. LRA Table 2.3.3-19-32-IP3 identifies low-pressure steam dump system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Main Turbine Generator System. The main turbine generator system, which receives steam from the SGs, converts a portion of the steam thermal energy to electricity, and supplies extraction steam for FW heating, consists of the turbine, generator, and instrumentation. This system does not include the control valves, moisture separator/reheaters, condensers, and generator cooling components. LRA Table 2.3.3-19-36-IP3 identifies main turbine generator system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Nuclear Equipment Drains System. The nuclear equipment drains system collects leakage and drainage from the primary plant equipment (e.g., charging pumps, containment fan cooler units). LRA Table 2.3.3-19-38-IP3 identifies nuclear equipment drains system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Process Radiation Monitoring System. The process radiation monitoring system monitors fluid streams for increasing radiation levels and generates an alarm or automatic action under abnormal conditions. LRA Table 2.3.3-19-40-IP3 identifies process radiation monitoring system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Primary Plant Sampling System. The primary plant sampling system obtains samples for laboratory analysis of reactor coolant and other reactor auxiliary systems during normal operation. The system also includes the post-accident reactor coolant sampling system, which obtains pressurized coolant samples following accidents. LRA Table 2.3.3-19-41-IP3 identifies primary plant sampling system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

River Water Service System. The river water service system functionally supports the CW system to supply cooling water from the Hudson River to the main condensers. LRA Table 2.3.3-19-47-IP3 identifies river water system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Main Generator Seal Oil System. The main generator seal oil system supplies oil to the main generator shaft seals to prevent hydrogen leakage from the generator into the turbine building. LRA Table 2.3.3-19-54-IP3 identifies seal oil system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Secondary Plant Sampling System. The secondary plant sampling system collects and transports samples to the sample room for laboratory analysis of the condensate, FW, and MS systems during normal operation. LRA Table 2.3.3-19-55-IP3 identifies secondary plant sampling system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Turbine Hall Closed Cooling System. The turbine hall closed cooling system supplies cooling water to condensate pumps; heater drain pumps; main boiler feed pumps; and station, instrument, and administration building air compressors. LRA Table 2.3.3-19-58-IP3 identifies turbine hall closed cooling system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Vapor Containment Hydrogen Analyzer System. The vapor containment hydrogen analyzer system monitors hydrogen and oxygen concentrations and post-LOCA hydrogen concentration in the containment atmosphere. Since a recent license amendment (License Amendment No. 228), hydrogen monitoring is no longer required as a safety function; however, the system remains available. LRA Table 2.3.3-19-59-IP3 identifies vapor containment hydrogen analyzer system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

Hydrogen System (added by applicant by letter dated March 12, 2008). The hydrogen system provides hydrogen to the main generator for cooling and to the CVCS for the VCT cover gas. LRA Table 2.3.3-19-65-IP3 identifies hydrogen system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.3.19.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.19 and the following UFSAR sections that were associated with these systems:

• ammonia/morpholine addition[3]	Section 10.2.6.
• auxiliary steam and condensate return[4]	Section 9.6.4
• circulating water[3]	Section 10.2.4
• extraction steam[3]	Section 10.2
• floor drains[3]	Sections 9.6.2.3 and 16.1.3
• gaseous waste disposal[4]	Sections 11.1 and 14.2.3
• hydrazine addition[3]	Section 10.2.6
• heater drain/moisture separator drain/vent[3]	Section 10.2.6
• instrument air closed cooling[4]	Section 9.6.3
• main turbine generator[3]	Section 10.2
• nuclear equipment drains[3]	Section 6.7.1.2
• process radiation monitoring[4]	Section 11.2.3.1
• primary plant sampling[4]	Section 9.4
• river water service[3]	Section 10.2.4
• main generator seal oil[3]	Section 10.2.2
• secondary plant sampling[3]	Section 9.4
• vapor containment hydrogen analyzer[4]	Section 6.8
• boron and layup chemical addition[3]	—
• chlorination[3]	—
• lube oil[3]	—
• low pressure steam dump[3]	—
• turbine hall closed cooling[3]	—

For those systems receiving a simplified Tier 1 evaluation, the staff reviewed the applicable LRA and UFSAR sections using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. For those systems receiving a detailed Tier 2 evaluation, the staff reviewed the applicable LRA sections, applicable UFSAR sections, and license renewal drawings (system components are shown on other associated system drawings). Based upon information provided in the UFSAR and the LRA, the staff evaluated the system functions described in LRA Section 2.3.3.19 to verify that the applicant had not omitted from the scope of license renewal any components with intended functions pursuant to 10 CFR 54.4(a). The staff

[3] The staff conducted a simplified Tier 1 system review for these systems as described in SER Section 2.3

[4] The staff conducted a detailed Tier 2 system review for these systems as described in SER Section 2.3.

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 and long-lived components subject to an AMR, in accordance with 10 CFR 54.21(a)(1).

The staff reviewed the list of IP3 systems the applicant identified in LRA Section 2.3.3.19 as not having any components in scope for 10 CFR 54.4(a)(2) for spatial interaction because they were already included in scope under 10 CFR 54.4(a)(1), functional (a)(2), or (a)(3). In RAI 2.3A.2.2-1, dated February 13, 2008, the staff asked the applicant to explain why it did not highlight on boundary drawings those piping segments directly attached to the IP2 CS system 10 CFR 54.4(a)(1) piping to indicate that they were included within the scope of license renewal. SER Section 2.3A.2.2.2 documents the staff's review of the applicant's response, dated March 12, 2008.

LRA Table 2.2-2-IP3 indicates that the hydrogen gas system is not within the scope of license renewal. This system, along with the nitrogen system, provides the VCT with gas for oxygen scavenging. Since the piping is directly connected to the VCT, the staff questioned whether the applicant should include the system within scope, in accordance with 10 CFR 54.4(a)(2), because of the potential for physical interaction between the nonsafety- and safety-related equipment. In its response, dated March 12, 2008, the applicant stated that the hydrogen system should be within scope, as required by 10 CFR 54.4(a)(2). The applicant amended the LRA to include the hydrogen system. SER Section 2.2B.3 documents the staff's review of the applicant's response, dated March 12, 2008.

During its review, the staff noted that the applicant did not specifically identify components on the license renewal drawings that are within the scope of license renewal under 10 CFR 54.4(a)(2). To determine that the applicant did not omit any components from scope under 10 CFR 54.4(a)(2), the staff used a sampling approach recommended in SRP-LR Section 2.3.3.1. In multiple RAIs, dated February 13, 2008, the staff asked the applicant to verify that it had included various segments of selected systems within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2). This sampling approach allowed the staff to confirm that the applicant had properly implemented its methodology for identifying the nonsafety-related portions of systems with a potential to adversely affect safety-related functions, in accordance with 10 CFR 54.4(a)(2).

In its response, dated March 12, 2008, the applicant stated that all components identified by the staff on the license renewal drawings are within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2), and subject to an AMR. Based on a review of its response, the staff finds that the applicant has adequately identified the components required to be within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2), and subject to an AMR.

2.3B.3.19.3 Conclusion

For each system described above, the staff reviewed LRA Section 2.3.3.19, the applicable UFSAR section and license renewal drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found instances in which the applicant omitted systems and components that should have been included within the scope of license renewal. The applicant has satisfactorily resolved these issues as discussed in the preceding staff evaluation. On the basis of its review, the staff finds that, for all the systems identified in LRA Section 2.3.3.19 the applicant has appropriately identified the 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).

2.3B.4 Scoping and Screening Results: Steam and Power Conversion System Unit 3

LRA Section 2.3.4 identifies the IP3 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:

- 2.3.4.1, “Main Steam”
- 2.3.4.2, “Main Feedwater”
- 2.3.4.3, “Auxiliary Feedwater”
- 2.3.4.4, “Steam Generator Blowdown”
- 2.3.4.5, “IP2 AFW Pump Room Fire Event”
- 2.3.4.6, “Condensate”

SER Sections 2.3B.4.1 through 2.3B.4.6, respectively, provide the staff’s reviews of IP3 systems described in LRA Sections 2.3.4.1 through 2.3.4.6. The staff’s findings for these systems are discussed below.

2.3B.4.1 IP3 Main Steam System

2.3B.4.1.1 Summary of Technical Information in the Application

LRA Section 2.3.4.1 describes the MS system, which includes the auxiliary steam and condensate return, condenser air removal, gland seal steam, high-pressure steam dump, reactor protection and control, reheat steam, and turbine generator hydraulic control systems.

The MS system conducts steam from the four SGs inside the containment structure to the turbine generator unit in the turbine generator building. The system has four MS pipes, one from each SG to the turbine stop and control valves, which are interconnected near the turbine. Each steam pipe has an MSIV and a non-return valve outside the containment. Five code safety valves and one PORV are located on each MS line outside the reactor containment and upstream of the isolation and non-return valves. A flow venturi upstream of the isolation valve measures steam flow. Steam pressure is also measured upstream of the isolation valve. The MS system supplies steam to the main boiler FW pump turbines and the AFW pump turbine. The MS system includes the main boiler FW pump turbines and the turbine steam bypass and low-pressure steam dump systems, which channel excess steam flow to the condenser. The SGBD flowpath includes MS system components.

The auxiliary steam and condensate return system supplies auxiliary steam to plant components for IP3 heating and for the recovery of condensate via the condensate return lines. The system supplies steam for heating throughout the plant to room and area heating units, refueling water and primary water storage tanks, boric acid batch mixing tank, and other areas. The system also supplies minor steam loads, such as the condenser waterbox air ejectors. System supply by the house service boiler or steam reboiler includes heaters, air ejectors, steam distribution piping and valves, condensate return piping, valves, pumps, tanks, instruments, and controls.

The condenser air removal system removes air and non-condensable gases from the condensers to prevent gas buildup that would interfere with steam condensation. Each condenser has a four-element, two-stage air ejector with a separate inter-condenser and common after-condensers. Normal air removal requires one air ejector unit per condenser. For initial condenser shell-side air removal, three non-condensing priming ejectors use steam from the MS system supplied through a pressure-reducing valve. The system monitors the air ejector exhaust for radioactivity. In an SG leak and the subsequent presence of radioactively contaminated steam in the secondary system, this radiation monitor detects the radioactive non-condensable gases that concentrate in the air ejector effluent. A high-activity-level signal automatically diverts the exhaust gases from the vent stack to the containment.

The gland seal steam system supplies steam to the main turbine and boiler FW pump turbine gland seals. The system includes pressure-regulating valves and distribution piping and valves.

The high-pressure steam dump system provides an MS flowpath, bypassing the turbine to the main condenser when the turbine generator cannot accept the steam flow. Two MS bypass lines, one on either side of the turbine, divert excess steam from the four MS lines directly to the condensers, when necessary, before they reach the turbine stop valves. From each of the MS bypass lines, six lines, each with a bypass control valve, discharge into the condenser. The system includes the bypass control valves and its piping, controls, and instruments.

The reactor protection and control system monitors primary and secondary plant parameters and trips the reactor to protect the reactor core and RCS. The reactor protection and control system is primarily electrical, but includes a small number of mechanical instrumentation components that form parts of the SG secondary-side pressure boundary.

The reheat steam system supplies reheated steam to the low-pressure turbines and steam from the MS system to the main boiler FW pump turbines. Steam from the high-pressure turbine exhaust passes through the moisture separator reheaters, which remove moisture and reheat the steam by main steam extracted before it reaches the turbine MS stop valves. Part of the extracted main steam goes to the main boiler FW pump turbines. The system includes the moisture separator reheaters, piping, valves, instruments, and controls.

The turbine generator hydraulic control system directly controls the main turbine. The system has electrical and mechanical components of the turbine hydraulic control system, including the main turbine stop valves, and parts of the MS system pressure boundary for Appendix R safe shutdown.

The MS system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure could prevent the satisfactory accomplishment of a safety-related function. In addition, the MS system performs functions that support fire protection and SBO.

Main steam components supporting the AFW system are reviewed with the AFW systems (LRA Section 2.3.4.3). Components containing air are reviewed with the compressed air systems (LRA Section 2.3.3.4). Condenser air removal system components in the containment penetration are reviewed with containment penetrations (LRA Section 2.3.2.5). Reactor protection and control components supporting the mechanical intended function are reviewed with the SGs (LRA Section 2.3.1.4).

The following LRA tables identify IP3 MS system component types that are within the scope of license renewal and subject to an AMR, as well as their intended functions:

- LRA Table 2.3.4-1-IP3
- LRA Table 2.3.3-19-2-IP3
- LRA Table 2.3.3-19-4-IP3
- LRA Table 2.3.3-19-24-IP3
- LRA Table 2.3.3-19-28-IP3
- LRA Table 2.3.3-19-35-IP3
- LRA Table 2.3.3-19-45-IP3
- LRA Table 2.3.3-19-57-IP3

2.3B.4.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.1; UFSAR Sections 7.2, 9.6.4, 10.2, 10.2.1, 10.2.2, and 10.2.5; and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.4.1, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3B.4.1-1, dated December 7, 2007, the staff noted that license renewal drawings for the IP3 MS system show the following valves within the scope of license renewal and subject to an AMR: PCV-1134, PCV-1135, PCV-1136, PCV-1137, MS-1-31, MS-1-32, MS-1-33, MS-1-34, PCV-1120, PCV-1121, PCV-1122, PCV-1123, PCV-1124, PCV-1125, PCV-1126, PCV-1127, PCV-1128, PCV-1129, PCV-1130, PCV-1131. The staff also noted that these valves are air operated and have associated air cylinders and air tubing that were excluded from the scope of license renewal. Since some of these valves appear to rely on pressurized air (pneumatic operation) to change position and fulfill their intended function, the staff asked the applicant to explain why it did not include the instrument air system, its tubing, and associated SOVs to the valves in question within the scope of license renewal, in accordance with 10 CFR 54.4(a).

In its response dated January 4, 2008, the applicant stated that the air operators are active components; therefore, they are not subject to an AMR, in accordance with 10 CFR 54.21(a)(1)(i) and NEI 95-10, Appendix B. The applicant further explained that the SOVs and air tubing associated with the air-operated valves in the MS system are within the scope of license renewal, but are not subject to an AMR because the majority of the air-operated valves shown on the MS license renewal drawings as within the scope of license renewal fail to their required position for accident mitigation. As such, these valves do not require pressurized air to fulfill their intended function, and pressure boundary of the air tubing is not necessary. The applicant stated that the atmospheric dump valves and MSIVs are an exception. These valves close upon loss of air, but are credited with being re-opened, as necessary, in an accident scenario, using standby nitrogen in bottles or compressed air stored in accumulators. The applicant explained that components used to re-open the MS system valves are subject to an AMR.

Based on its review, the staff finds the response to RAI 2.3B.4.1-1 acceptable because the applicant adequately explained that, for most of the air-operated valves, a failure of the air supply system will not result in a loss of the intended function because the MS valves fail to their safe positions. This explanation is consistent with NEI 95-10, Revision 6, Section 5.2.3.1, which governs fail-safe components. For those air-operated valves that rely on an air supply system (i.e., those MS system valves that do not fail to their safe position), the passive pneumatic components (accumulator tanks, tubing, and valves) of those air-operated valves are included within the scope of license renewal and are subject to an AMR, in accordance with 10 CFR 54.21(a)(1). The staff's concern described in RAI 2.3B.4.1-1 is resolved.

2.3B.4.1.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has appropriately identified the MS system 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).

2.3B.4.2 IP3 Main Feedwater System

2.3B.4.2.1 Summary of Technical Information in the Application

LRA Section 2.3.4.2 describes the FW system, which transfers condensate and heater drain flow through the final stage of FW heating to the SGs. Two half-size, steam-driven main FW pumps increase the pressure of the condensate for delivery through the final stage of FW heating and the FW regulating valves to the SGs.

The main FW system includes the high-pressure FW heaters and piping and valves from the main feed pumps through the heaters to the SGs. The FW system also includes the main feed pump turbine drip tank drain pumps. The main FW pumps and services system supports the main FW system by increasing the pressure of the condensate for delivery through the final stage of FW heating and the FW regulating valves to the SGs.

The main FW system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the main FW system performs functions that support fire protection.

Feedwater system components supporting the AFW system are reviewed with such systems (LRA Section 2.3.4.3).

LRA Tables 2.3.4-2-IP3, 2.3.3-19-22-IP3, and 2.3.3-19-23-IP3 identify main FW system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.2, UFSAR Section 10.2.6, and a license renewal drawing using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During its review of LRA Section 2.3.4.2, the staff identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3B.4.2-1, dated December 7, 2007, the staff noted that license renewal drawings identify valves FCV-417-L, FCV-417, FCV-427-L, FCV-427, FCV-437-L, FCV-437, FCV-447-L, FCV-447, BF2-31, and BF2-32 for the IP3 main FW system as within the system evaluation boundary. The staff noted that, although the aforementioned valves are passive and long lived, they are not highlighted, indicating that they are not subject to an AMR. The staff asked the applicant to explain the valves' exclusion from an AMR.

In its response, dated January 4, 2008, the applicant explained that, although these FW system valves are located upstream of the containment isolation check valves in nonsafety-related piping, they are classified as safety related because of their active function to provide FW isolation. The applicant also stated that these valves "have no passive intended function for 54.4 (a)(1) or (a)(3) because their failure would accomplish the safety function of isolating feedwater flow to the SGs." The applicant further stated that these valves perform their function with moving parts; therefore, in accordance with 10 CFR 54.21(a)(1)(i), they are not subject to an AMR and are not highlighted on the license renewal drawing. However, the applicant did indicate that the valves in question are within the scope of license renewal under 10 CFR 54.4(a)(2) because of their potential for spatial interaction with safety-related equipment; therefore, they are subject to an AMR.

The staff disagreed with the applicant's rationale that the valves do not have a passive intended function in accordance with 10 CFR 54.4(a)(1). The staff discussed the applicant's view during a telephone call on March 7, 2008. The applicant subsequently amended its RAI response by letter dated March 24, 2008, and reiterated that the FW system valves are safety related. The applicant also stated that, although not highlighted, these valves and the remainder of the FW system components on the associated license renewal drawing are in scope and subject to an AMR under 10 CFR 54.4(a)(2) because of their potential for spatial interaction with safety-related equipment.

Based on its review, the staff finds the applicant's amended response to RAI 2.3B.4.2-1 acceptable because the applicant confirmed that the valves in question are within the scope of license renewal pursuant to 10 CFR 54.4(a), and subject to an AMR pursuant to 10 CFR

54.21(a)(1). Although the staff does not agree with the applicant's basis for determining how the valve bodies are subject to an AMR, the staff's concern is resolved because the AMR was performed, and the AMR results were provided in LRA Table 3.3.2-19-34-IP3. The staff's concern described in RAI 2.3B.4.2-1 is resolved.

In RAI 2.3B.4.2-2, dated December 30, 2007, the staff noted that UFSAR Section 14.2.5, Rupture of a Steam Pipe, states in the event of a main steam line break incident, the motor-operated valves (MOVs) associated with each of the feedwater regulating valves (FRVs) will close. UFSAR Section 14.2.5.1 states that redundant isolation of the main feedwater lines is necessary, because sustained high feedwater flow would cause additional cooldown; therefore, in addition to the normal control action which will close the main feedwater valves, any safety injection signal will rapidly close all feedwater control valves (including the motor-operated block valves and low-flow bypass valves), trip the main feedwater pumps, and close the feedwater pump discharge valves. In addition, license renewal drawing 9321-20193 shows a "HIGH STEAM FLOW SI LOGIC" signal going to these motor-operated isolation valves. The motor-operated block valves shown on license renewal drawings are BFD-5s and BFD-90s for the main FRVs, and the low flow bypass regulating valves, respectively.

The feedwater isolation valves, BFD-5s and BFD-90s, are not included within the "system intended function boundary," nor are they highlighted on the license renewal drawings as having an intended function in accordance with 10 CFR 54.4(a)(1). By letter dated December 30, 2008, the staff requested the applicant to justify the exclusion of the BFD-5 and BFD-90 isolation valves from scope of license renewal in accordance with 10 CFR 54.4(a)(1). This issue was also identified as Open Item 2.3.4.2-1.

By letter dated January 27, 2009, the applicant stated that based upon a review of the qualifications of the isolation valves, the BFD-5 and BFD-90 valves are classified as nonsafety-related in the site component database and are located outside the Class I boundary [as corrected by letter dated March 13, 2009] on license renewal drawing LRA-9321-2019-0. As indicated in the IP3 UFSAR, these valves provide a backup isolation function for feedwater in the event of such accidents as a feedwater or steamline break. Credit for nonsafety-related components as a backup to safety-related components in mitigating breaks in seismically-qualified steam line piping is consistent with regulatory guidance provided in Standard Review Plan (NUREG-0800), Section 15.1.5, "Steam System Piping Failures Inside and Outside of Containment (PWR)," and is also consistent with the allowance for feedwater regulating and bypass valves to be nonsafety-related, as discussed in NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum from Director, NRR to NRR Staff." The applicant concluded that, consistent with the CLB, regulatory guidance, and NUREG-0138, the BFD-5 and BRD-90 valves are classified as nonsafety-related, and as such, meet the criteria to be included in scope for license renewal under 10 CFR 54.4(a)(2).

Based on the information provided by the applicant, the staff finds applicant's response to RAI 2.3B.4.2-2 acceptable because the BFD-5 and BFD-90 isolation valves are nonsafety-related components, and the valves are included in the scope for license renewal under 10 CFR 54.4(a)(2). Therefore, the staff's concern described in RAI 2.3B.4.2-2 is resolved. As a result, Open Item 2.3.4.2-1 is closed.

2.3B.4.2.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI response, and a drawing to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. The staff concludes that the applicant has appropriately identified the main FW system 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).

2.3B.4.3 IP3 Auxiliary Feedwater System

2.3B.4.3.1 Summary of Technical Information in the Application

LRA Section 2.3.4.3 describes the AFW system, which supplies a flow of water from the CST to the SGs when the main FW pumps are unavailable. One steam turbine-driven and two electric motor-driven AFW pumps supply adequate feedwater to the SGs to remove reactor decay heat under all circumstances, including loss of power and normal heat sink (e.g., condenser isolation or loss of CW flow). The system can supply all four SGs. The steam-turbine-driven pump can be supplied from two of the SGs. The AFW system operates during plant startup at low power levels before the main FW pump is available. The system includes the AFW pumps, the turbine for the turbine-driven pump, piping from both CST and city water supply (an alternate source) through the pumps to the FW line supplying the SGs, valves, instruments, and controls. However, the system does not include the CST, which is part of the condensate transfer system.

The AFW system contains safety-related components relied on to remain functional during and following DBEs. In addition, the AFW system performs functions that support fire protection, ATWS, and SBO. Instrument air components included in the AFW system are reviewed with the compressed air systems (LRA Section 2.3.3.4).

LRA Table 2.3.4-3-IP3 identifies AFW system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.3, UFSAR Sections 7.2.2 and 10.2.6, and license renewal drawings using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

During 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 applicant responded to the staff's RAI as discussed below.

In RAI 2.3A.4.2-2, dated February 13, 2008, the staff noted that LRA Section 2.3.4.3 states that the AFW system has no intended function under 10 CFR 54.4(a)(2). However, the staff identified an instance in which components adjacent to safety-related components were not highlighted on license renewal drawings, but should have been considered for inclusion within the scope of license renewal because of their potential adverse spatial interaction, in accordance with 10 CFR 54.4(a)(2). For IP3, a license renewal drawing showed a section of piping extending from the AFW system piping (which includes valve SS-189) that was not highlighted. The staff asked the applicant to confirm that it evaluated the aforementioned components for inclusion within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2).

In its response, dated March 12, 2008, the applicant stated that the section of piping extending from the AFW system piping, which includes valve SS-189 is included within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2), and is subject to an AMR.

Based on its review, the staff finds the applicant’s response to RAI 2.3A.4.2-2 acceptable because it adequately explained that the components in question are within the scope of license renewal, in accordance with 10 CFR 54.4(a)(2), and subject to an AMR because of their potential to adversely interact spatially with safety-related equipment. The staff’s concern described in RAI 2.3A.4.2-2 is resolved.

2.3B.4.3.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI responses, and drawings to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has appropriately identified the AFW system 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).

2.3B.4.4 IP3 Steam Generator Blowdown System

2.3B.4.4.1 Summary of Technical Information in the Application

LRA Section 2.3.4.4 describes the SGBD system, which includes the SGBD recovery and the SG sampling systems.

The SGBD system can control the concentration of solids in the shell side of the SGs. The system, which operates normally with a continuous blowdown and sample flow, has a drain connection and two blowdown connections (nozzles) at the bottom of each SG. Pipes from the connections (nozzles) join to form a stainless steel blowdown header. Four individual blowdown headers are routed from each SG to the PAB through containment isolation valves.

Downstream of the containment isolation valves, blowdown flow can be diverted to either the SGBD recovery system (during normal operation) or the blowdown flash tank. The SGBD recovery system consists of two heat exchangers, a filter and demineralizer package, piping, valves, and instrumentation.

The SG sampling system obtains representative secondary-side water samples for laboratory analysis of chemical and radiochemical conditions. The system has sample capability for each SG from its blowdown line inside containment. Each line to the sample room, where the liquid is cooled and the pressure reduced, has a containment penetration. Each sample is split into two routes—one to the sample sink for periodic chemical analysis and one to a conductivity cell, a radiation monitor, and then to the blowdown flash tank. The second line handles a continuous flow for constant conductivity reading and radiation monitoring.

The SGBD system contains safety-related components relied on to remain functional during and following DBEs. It also contains nonsafety-related components whose failure potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the SGBD system performs functions that support fire protection, ATWS, and SBO.

A small number of SGBD components are reviewed with the SW system (LRA Section 2.3.3.2). The SG sample heat exchangers (SG sampling system) are safety-related only for their cooling water pressure boundary function (heat transfer is not a required function). These heat exchangers are reviewed with the CCW system (LRA Section 2.3.3.3).

LRA Tables 2.3.4-4-IP3, 2.3.3-19-50-IP3, 2.3.3-19-51-IP3, and 2.3.3-19-52-IP3 identify SGBD system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.4.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.4 and UFSAR Sections 9.4.1 and 10.2.1 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3B.4.4.3 Conclusion

The staff reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the SGBD system 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).

2.3B.4.5 IP2 Auxiliary Feedwater Pump Room Fire Event (Not Applicable to IP3)

In the LRA, the applicant evaluates systems that in combination provide and support feedwater flow to the steam generators during a shutdown, and states that the evaluation applies to IP2 only. During its review, the staff considered whether a similar evaluation was needed for IP3.

Similar to IP2, the IP3 AFW pump room contains redundant trains of safe shutdown systems and equipment separated by 20 feet with intervening combustibles. The NRC granted an exemption from the technical requirements of Section III.G.2 of 10 CFR Part 50, Appendix R on January 7, 1987. However, the AFW pump room fire event is not an issue at IP3 because the AFW pump room has area-wide coverage via automatic fire detection and a sprinkler system. This area is also equipped with manual hose stations and portable fire extinguishers. The NRC SER dated January 7, 1987, documents the staff's determination that fire protection features in the IP3 AFW Pump Room are adequate.

The staff finds that the applicant has demonstrated that the IP3 AFW pump room contains sufficient automatic fire suppression, the fire hazard within this area is low, and alternate shutdown capability exists. Therefore, an alternate feedwater flowpath is not required in the event of a fire in the IP3 AFW pump room.

2.3B.4.6 IP3 Condensate System

2.3B.4.6.1 Summary of Technical Information in the Application

LRA Section 2.3.4.6 describes the condensate system, which consists of components in the following systems: condensate, condensate polisher, condensate pump discharge, condensate pump suction, and condensate transfer.

The condensate system transfers condensate and low-pressure heater drainage from the condenser hotwell through the condensate polisher and five stages of FW heating to the main FW pump suctions. The condensate system is also the primary source of water to the AFW pumps. As part of the main condensate flowpath, three condensate pumps, arranged in parallel, take suction from the bottom of the condenser hotwells and discharge into a common header to the condensate polisher system. From the polisher system, a portion of the condensate passes through three steam jet air ejector condensers, arranged in parallel, and one gland steam condenser. The condensate passes through the tube sides of three parallel strings of two low-pressure FW heaters. The flows from these heaters combine in a common line, which then divides to flow into the remaining three strings of three low-pressure heaters. After the No. 5 FW heater, the three condensate lines join into a common header. The heater drain pump discharge enters this header and continues on to the suction of the main FW pumps.

The condensate system contains mostly valves, including a large number of small valves supplying condensate as gland seal water to various secondary plant valves. Within the condensate system, one valve has a safety function as part of the pressure boundary for the flowpath from the CST to the AFW pumps.

The condensate polishing system removes dissolved and suspended solids from the condensate to maintain FW quality required for the SGs. The polishers are within the existing condensate system between the condensate pumps and the first stage of FW heaters. The condensate polishing system consists of six service vessels, six condensate post-filters, three condensate booster pumps, piping, valves, instrumentation, and controls.

The condensate pump discharge system supports sampling of the condensate pump discharge. Components in this system code include the small sampling piping and valves at the discharge of the condensate pumps.

The condensate pump suction system supplies water to the condensate pumps from the main condenser. Components in this system code include the expansion joints, piping, and valves between the condenser and the condensate pumps.

The condensate transfer system transfers condensate from the condenser to the suction of the main boiler FW pumps and from the CST to the AFW pumps. This system includes condensate system components from the condensate pumps to the suction of the main boiler FW pumps (except the condensate polishers and their support equipment), the CST and piping and components to the AFW pump suction header, the main condensers, the condensate and low-pressure FW heaters, piping, valves, instruments, controls, and other condensate system components.

The condensate system contains safety-related components relied on to remain functional during and following DBEs. The failure of nonsafety-related SSCs in the condensate system potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the condensate system performs functions that support fire protection and SBO.

Components that support the pressure boundary of the AFW system flowpath are evaluated with the AFW systems (LRA Section 2.3.4.3).

LRA Tables 2.3.3-19-6-IP3, 2.3.3-19-7-IP3, 2.3.3-19-8-IP3, 2.3.3-19-9-IP3, and 2.3.3-19-14-IP3 identify condensate system component types within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.3B.4.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.6, UFSAR Section 10.2.6, and license renewal drawings (condensate system components are shown on drawings of other system) using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

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

2.3B.4.6.3 Conclusion

The staff reviewed the LRA and UFSAR to determine whether the applicant failed to identify any SSCs within the scope of license renewal. The staff found no such omissions. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the condensate system 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).

2.4 Scoping and Screening Results: Structures

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

- containment buildings
- water control structures
- turbine buildings, auxiliary buildings, and other structures
- bulk commodities

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

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

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

After its review of the scoping results, the staff evaluated the applicant's screening results. For those SCs with intended functions, the staff sought to determine whether (1) the functions are performed with moving parts or a change in configuration or properties or (2) the SCs are subject to replacement after a qualified life or specified time period, in accordance with 10 CFR 54.21(a)(1). For those meeting neither of these criteria, the staff sought to confirm that these SCs were subject to an AMR, as required by 10 CFR 54.21(a)(1). The staff requested additional information to resolve any omissions or discrepancies identified.

During its review of LRA Section 2.4, the staff identified areas in which additional information was necessary to complete the evaluation of the applicant's scoping and screening results for structures. Therefore, the staff issued issue-specific RAIs by letter dated January 28, 2008, to determine or confirm whether the applicant properly applied the scoping criteria of 10 CFR 54.4(a) and the screening criteria of 10 CFR 54.21(a) to structures and structural components. The applicant provided its responses to the staff's RAIs by letter dated February 27, 2008, and supplemented it by Amendment 3 to the LRA, dated March 24, 2008. The applicant further provided responses to the staff's followup RAIs by letter dated June 11, 2008, and submitted Amendment 5 to the LRA, dated June 11, 2008.

The following discussion describes the staff's RAI related to the scoping of structures in LRA Section 2.4, and the applicant's responses. Relative to the applicant's scoping and screening results for structures documented in LRA Section 2.4, the staff also reviewed LRA Table 2.2-3, which lists the plant-level structures that are within the scope of license renewal, and LRA Table 2.2-4, which lists the plant-level structures that are not within the scope of license renewal. The staff performed these reviews to determine if there were any omissions in the structures scoped at the plant-level and to verify that all the scoped structures were addressed in LRA Section 2.4.

Based on its review of the UFSAR, the staff identified certain structural components that do not appear to be included in LRA Tables 2.2-3 and 2.2-4 or in LRA Section 2.4. In the first part of RAI 2.4-1, the staff requested that the applicant explain whether or not the structures listed below are within the scope of license renewal and subject to an AMR:

(i) pipe penetration tunnel (Reference: IP2 final safety analysis report (FSAR), Section 1.11.4.10)

(ii) liquid waste storage building (Reference: IP3 FSAR, Sections 16.1.2 and 9.6.4)

(iii) condenser tube withdrawal/removal pit (Reference: IP3 FSAR, Chapter 1; Site Plan Drawing 64513; and IP2 FSAR, Figure 10.2-3)

(iv) fuel oil storage tank and its foundation at Buchanan Substation (this tank provides backup fuel oil for emergency diesels and gas turbines)

In its response to RAI 2.4-1, Item (i), dated February 27, 2008, the applicant stated that the pipe penetration tunnel is located in the IP2 fan house and is included within the scope of license renewal as part of the fan house structure, identified in LRA Table 2.2-3 as "fan house (IP2)." The staff verified that LRA Table 2.2-3, as well as LRA Section 2.4.3, identified the "fan house (IP2)" as a structure. Therefore, the staff finds the applicant's response acceptable. The staff's concern described in RAI 2.4-1, Item (i), is resolved.

In its response to RAI 2.4-1, Item (ii), dated February 27, 2008, the applicant stated that the liquid waste storage building is located within the administration building. The applicant stated that the liquid waste storage building is not within the scope of license renewal because it does not perform a license renewal intended function, as required by 10 CFR 54.4(a). Therefore, LRA Table 2.2-4 lists the liquid waste storage building as part of the line item "administration building (IP3) (service admin complex)." The staff verified that LRA Table 2.2-4 lists "administration building (IP3) (service admin complex)" as a structure that is not within the scope of license renewal. The staff further confirmed from UFSAR Section 16.1.2 for IP3 that the liquid waste storage building is a seismic Class III component of the waste disposal system. Its failure will not result in offsite doses in excess of the limits required by 10 CFR Part 20, "Standards for Protection against Radiation." Based on the above, the staff finds that the liquid waste storage building does not perform a license renewal intended function, as detailed in 10 CFR 54.4(a). Therefore, the staff finds the applicant's response acceptable. The staff's concern described in RAI 2.4-1, Item (ii), is resolved.

In its response to RAI 2.4-1, Item (iii), dated February 27, 2008, the applicant stated that the condenser tube withdrawal/removal pits are located in the lower level of the turbine buildings. The applicant included these components in the scope of license renewal as part of the structures identified in LRA Table 2.2-3 as "turbine building and heater bay (IP2)" and "turbine building and heater bay (IP3)." The staff verified that LRA Table 2.2-3, as well as LRA

Section 2.4.3, identifies the "turbine building and heater bay (IP2)" and "turbine building and heater bay (IP3)" as structures. Therefore, the staff finds the applicant's response acceptable. The staff's concern described in RAI 2.4-1, Item (iii), is resolved.

In its response to RAI 2.4-1, Item (iv), dated February 27, 2008, the applicant stated that the "fuel oil storage tank foundation" at Buchanan Substation is within the scope of license renewal and included within the line item "gas turbine generator No. 2 and 3, enclosure and fuel tanks foundation" in LRA Table 2.2-3. The staff verified that LRA Table 2.2-3, as well as LRA Section 2.4.3, identifies the line item "gas turbine generator No. 2 and 3, enclosure and fuel tanks foundation." Further, the staff verified that the fuel oil storage tanks are scoped and screened as a mechanical fuel oil system component in LRA Section 2.3.3.13 and not in LRA Section 2.4.3. The staff finds that the applicant's response addressed the staff's question and, therefore, is acceptable. The staff's concern described in RAI 2.4-1, Item (iv), is resolved.

In its response, dated February 27, 2008, the applicant concluded that, as a result of this RAI, the applicant did not have to revise LRA Tables 2.2-3 or 2.2-4. The staff finds that the applicant appropriately confirmed and justified the license renewal scoping of the specific structures and structural components that were in question in the first part of RAI 2.4-1; therefore, the applicant's response to the first part of RAI 2.4-1 is acceptable. The staff's concerns described in the first part of RAI 2.4-1 are resolved. SER Section 2.4.3.2 discusses the second part of RAI 2.4-1.

Based on the information provided in the LRA, the RAI response discussed above, and the UFSAR, the staff concludes that, in LRA Section 2.4, the applicant identified, without omissions, the structures that are within the scope of license renewal for IP2 and IP3, in accordance with 10 CFR 54.4(a).

2.4.1 Containment Buildings (IP2 and IP3)

2.4.1.1 Summary of Technical Information in the Application

LRA Section 2.4.1 describes the containment buildings, which completely enclose the entire reactor and the RCS and ensures that essentially no leakage of radioactive materials to the environment would result even if a design basis LOCA occurs. The reactor containment structure is a seismic Class I, reinforced concrete vertical right cylinder with a flat base and hemispherical dome. A welded steel liner attached to the inside face of the concrete shell ensures a high degree of leak-tightness. The liner has accommodations for penetrations and personnel access. For IP2, the steel liner plate is covered by polyvinyl chloride insulation in a stainless steel jacket. For IP3, the steel liner plate is covered by urethane foam insulating material covered with gypsum board and a stainless steel jacket and backed with a fire-retardant paper on the unexposed side. The containment liner is anchored to the concrete shell by stud anchors. The bottom liner plate on top of the reinforced concrete base mat is covered with additional concrete, the top of which forms the floor of the containment. Internal structures consist of equipment supports, shielding, reactor cavity and canal for fuel transfer, manipulator crane, containment crane, and miscellaneous concrete and steel for floors and stairs. All internal structures are supported on the mat except equipment supports which are secured to the intermediate floors.

The containment buildings contain safety-related components relied on to remain functional during and following DBEs. The failure of nonsafety-related SSCs in the containment buildings potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the containment buildings perform functions that support fire protection.

LRA Table 2.4-1 identifies containment buildings component types, grouped by material (steel/other metals, concrete, other materials) within the scope of license renewal and subject to an AMR, as well as their intended functions.

2.4.1.2 Staff Evaluation

The staff reviewed LRA Section 2.4.1; IP2 UFSAR Sections 1.2.2, 1.11.2, and 5.1.2; and IP3 UFSAR Sections 1.3.5, 5.1.2, and 16.1.2 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4, "Scoping and Screening Results: Structures."

During its review, the staff evaluated the structural component functions described in the LRA and UFSAR to verify that the applicant had not omitted from the scope of license renewal any SCs with intended functions, as required by 10 CFR 54.4(a). The staff then reviewed those SCs that the applicant identified as within the scope of license renewal to verify that it had 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 2.4.1, the staff identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

In RAI 2.4.1-1, dated January 28, 2008, the staff noted that UFSAR Section 5.1.2.1 (IP2 and IP3) states that the containment structure serves as both a biological shield and a pressure boundary component. Since the biological shield function was not explicitly listed among the intended functions for containment buildings in LRA Section 2.4.1 and LRA Table 2.4-1, in RAI 2.4.1-1, the staff requested that the applicant clarify and include biological shield function as an intended function for containment buildings in the LRA.

In its response, dated February 27, 2008, the applicant stated that the biological shield function is an intended function for the IP2 and IP3 containment buildings. The applicant further stated that this intended function is implicit in the definition of the shelter or protection function *EN* in LRA Table 2.0-1, which includes "radiation shielding." The staff verified that the definition of the *EN* function in LRA Table 2.0-1 does include "radiation shielding" within parenthesis. The staff finds the response to be acceptable since it refers to an intended function. Therefore, the applicant's response to RAI 2.4.1-1 has adequately addressed the issue raised by the staff and is acceptable. The staff's concern described in RAI 2.4.1-1 is resolved.

A lack of clarity in LRA Table 2.4-1 prompted the staff to seek clarification. In RAI 2.4.1-2, the staff requested that the applicant confirm and/or clarify whether the following components associated with the containment buildings are included as components subject to an AMR in LRA Table 2.4-1 or justify their exclusion. For the components that are subject to an AMR, the applicant was requested to provide the appropriate AMR results in LRA Section 3.5.

(i) primary shield wall around the reactor

(ii) control rod drive missile shield

(iii) retaining wall at the equipment hatch entrance and its missile shield (fixed and removable)

(iv) blowout shield plug

(v) insulation for the containment building liner (limits temperature rise in liner under accident conditions)

(vi) protective coating for liner

(vii) water proofing around fuel transfer tube

(viii) waterproof membrane for containment wall against backfill

(ix) reactor cavity seal ring (see UFSAR Figures 5.1-6 and 5.1-7)

(x) Seismic Class I debris screens at containment purge (Ref. UFSAR Section 5.1.4.2.4)

(xi) stud anchors that anchor the containment liner plate to the concrete shell

In its response, dated February 27, 2008, the applicant addressed each of the components identified in the RAI with respect to whether they are subject to an AMR, as indicated below:

(i) The primary shield wall around the reactor is included as part of “beams, columns, interior walls, slabs” listed in LRA Table 2.4-1. AMR results are provided in Table 3.5.2-1.

(ii) The control rod drive missile shield is included with the line item “missile shields” listed in Table 2.4-4. AMR results are provided in Table 3.5.2-4.

(iii) The retaining wall at the equipment hatch entrance is included as part of “beams, columns, interior walls, slabs” listed in LRA Table 2.4-1. AMR results are provided in Table 3.5.2-1. The equipment hatch missile shield (fixed and removable) is included with the line item “missile shields” listed in Table 2.4-4. AMR results are provided in Table 3.5.2-4.

(iv) Components/commodities identified in scope that provide missile protection are addressed in LRA Section 2.4-4 and Table 2.4-4. The “blowout shield plug” is included with the line item “missile shields” listed in LRA Table 2.4-4. AMR results are provided in Table 3.5.2-4.

(v) The insulation for the containment building liner is included in Table 2.4-1 with line item “liner insulation jacket.” AMR results are provided in Table 3.5.2-1.

(vi) Protective coatings are not in the scope of license renewal because they do not perform an intended function. Their failure will not prevent satisfactory accomplishment of a safety function.

(vii) The waterproofing material around the fuel transfer tube is not in scope. Waterproofing membranes have no license renewal intended function.

(viii) The waterproof membrane for containment wall against backfill is not in scope. Waterproofing membranes have no license renewal intended function.

(ix) The reactor cavity seal ring identified in UFSAR Figures 5.1-6 and 5.1-7 has no license renewal intended function. This component is not safety-related and is not required to demonstrate compliance with regulations identified in 10 CFR 54.4(a)(3). Failure of the seal ring will not prevent satisfactory accomplishment of a safety function. The seal is provided to prevent leakage during refueling operations. This component is not listed in LRA Table 2.2-4 since it does not meet the threshold of a major structural component.

(x) The seismic Class I debris screens at containment purge identified in UFSAR Section 5.1.4.2.4 do not perform a license renewal intended function. The primary containment isolation valves in the containment purge and pressure relief exhaust ducts are closed during normal plant operation. Failure of the screens will not prevent the ventilation systems from performing their intended function. These components are not required during design basis accidents or for any regulated event. The structural support of this component is included in scope and is included with line item "Structural steel: beams, columns, plates, trusses" listed in LRA Table 2.4-1.

(xi) The stud anchors that anchor the containment liner plate to the concrete shell are included in the line item "anchorages/embedments" listed in LRA Table 2.4-4. AMR results are provided in Table 3.5.2-4.

In its response, dated February 27, 2008, the applicant has confirmed/clarified the screening of each of the components in question and provided justification of the components that are not subjected to an AMR. The staff finds the applicant's response to Items (ii), (iv), and (xi) acceptable because the applicant explicitly clarified that the components in question are within the scope of license renewal and are subject to an AMR. The staff finds the applicant's response to Items (vii), (viii), and (x) acceptable because the applicant explicitly clarified that the components in question do not have an intended function that meets any of the criteria in 10 CFR 54.4(a). Therefore, the staff finds that the applicant's response to RAI 2.4.1-2 is acceptable, with the following exceptions with regard to the response to Items (i), (iii), (v), (vi) and (ix) of RAI 2.4.1-2. In a follow-up RAI to RAI 2.4.1-2, dated May 12, 2008, the staff requested the applicant to clarify/address these exceptions. The applicant provided clarification responses to the follow-up RAI items by letter dated June 11, 2008. The follow-up RAI items and their resolution are discussed below.

- With regard to Item (i), the response stated that Primary Shield Wall is included as part of line item "Beams, columns, interior walls, slabs" in LRA Table 2.4-1. The staff noted that walls with lesser safety-significance, such as pressurizer shield, ring wall, and cylinder walls, have been listed as separate items in LRA Table 2.4-1. Considering that the primary shield wall is subjected to a more severe environment (high temperature and radiation exposure) and has a much higher safety-significance than the general interior wall, the staff requested, in a follow-up RAI dated May 12, 2008, that the applicant include the primary shield wall as a separate line item in LRA Table 2.4-1, to make its inclusion in the scope of license renewal and its consideration as being subject to AMR, explicitly clear.

  In its response, dated June 11, 2008, the applicant added the primary shield wall as a separate concrete component item in LRA Tables 2.4-1 and 3.5.2-1 with the appropriate intended functions. By doing so, the applicant has explicitly included the primary shield wall as a component subject to AMR. Therefore, the staff finds the response acceptable. The staff's evaluation of the AMR results for the primary shield wall is documented in SER

Section 3.5.

- With regard to Item (iii), the response stated that the retaining wall is included as part of line item “Beams, columns, interior walls, slabs” in LRA Table 2.4-1. The staff noted that the retaining wall at the equipment hatch entrance is an exterior wall and is subjected to a different environment than the interior wall. Therefore, in a follow-up RAI dated May 12, 2008, the staff requested the applicant to explicitly include the retaining wall at the equipment hatch entrance in LRA Table 2.4-1 as a separate line item.

  In its response, dated June 11, 2008, the applicant added the equipment hatch entry retaining wall (exists for IP2 only) as a separate concrete component item in LRA Tables 2.4-1 and 3.5.2-1 with the appropriate intended functions. By doing so the applicant has explicitly included the IP2 retaining wall at the equipment hatch entrance as a component subject to AMR. Therefore, the staff finds the response acceptable.

- With regard to Item (v), the response stated that liner plate insulation is included with line item “Insulation Jacket” in LRA Table 2.4-1. The staff noted that materials for the insulation jacket and the insulation itself are not the same. The jacket is stainless steel but the insulation is PVC for IP2 and Urethane foam covered with gypsum board for IP3 (UFSAR Section 5.1). The insulation itself is not included in LRA Table 2.4-1 or LRA Table 2.4-4; nor are these materials identified in LRA Sections 3.5.2.1.1 or 3.5.2.1.4. They also were not addressed in the response to RAI 2.4.4-2. In a follow-up RAI dated May 12, 2008, the staff requested the applicant to appropriately address the scoping, screening, and AMR results for these in-scope insulation materials in the LRA.

  In its response, dated June 11, 2008, the applicant stated that the IP2 containment liner plate PVC insulation and IP3 containment liner urethane insulation are encapsulated within stainless steel jacketing (IP2 UFSAR Section 6C.8.4, and IP3 UFSAR Section 5.5) and are not exposed to containment atmosphere. The only visible and exposed parts of the insulation are the stainless steel jacketing. The aging management review results in LRA Table 3.5.2-1 for the liner plate insulation pertain to the stainless steel jacketing. The applicant added that the containment liner plate insulation within the jacketing is in scope and subject to aging management review for providing shelter and protection to the containment liner plate. The PVC and urethane insulation materials have no aging effects in the air-indoor environment and, therefore, no aging management program is necessary.

  In the above response, the applicant has clarified that, for both IP2 and IP3, the containment liner plate insulation within the jacketing is within the scope of license renewal and subject to AMR but does not need aging management since there are no aging effects in its protected environment. Based on the above response, it is the staff’s understanding that the PVC and urethane insulation are encapsulated within the stainless steel insulation jacketing forming one composite unit, and the AMR results in LRA Table 3.5.2-1 for the line item “liner plate insulation jacket” includes the encapsulated insulation, which is exposed to an indoor air environment that does not promote aging effects. The staff finds that the applicant’s response addressed the staff’s concern with regard to scoping and screening of the liner insulation and, therefore, is acceptable.

- With regard to Item (vi), the response stated that protective coatings for the containment liner are not in scope because they do not perform an intended function. Staff noted that, although protective coating on the containment liner does not directly perform a license renewal function, it prevents degradation of the liner if properly maintained. Section XI.S8 of NUREG-1801, Volume 2, which is the AMP for protective coatings, recommends maintenance of the protective coatings to avoid clogging of the sumps. The GALL Report requires that, 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 (Item 25 in Table 5 of NUREG-1801, Volume 1). Therefore, in a follow-up RAI dated May 12, 2008, the staff requested the applicant to provide justification for excluding the protective coating on the containment liner from the scope of license-renewal and from being subject to an AMR.

In its response, dated June 11, 2008, the applicant stated that the liner plates of IP2 and IP3 containment are provided with protective coatings. The applicant stated that, in response to Generic Safety Issue (GSI)-191, "Assessment of Debris Accumulation on PWR Sump Performance," the applicant's Civil/Structural Engineering group visually inspects coatings in the vapor containment building during refueling outages. Sump clogging for IP2 and IP3 was evaluated, and the evaluation results were provided by Entergy, Inc., in letter dated September 1, 2005, in response to NRC generic letter 2004-02, "Potential impact of debris blockage on emergency recirculation during design basis accidents at pressurized water reactors."

The applicant further added that the GALL Report states that, if protective coatings are relied upon to manage the effects of aging, the structures monitoring program should include provisions to address protective coating monitoring and maintenance. The applicant stated that, as indicated in LRA Table 3.5.1, Item 3.5.1-25, IP2 and IP3 containment liner protective coatings are not relied upon to manage the effects of aging. As shown in LRA Table 3.5.2-1, aging effects of liner plate and integral attachments are managed by the Containment Inservice Inspection-IWE and Containment Leak Rate Test programs for license renewal. Accordingly, the protective coating on the containment liner is not within the scope of license renewal and, therefore, is not subject to aging management review.

In the above response, the applicant clarified that inspection commitments of protective coatings and sump clogging evaluations were addressed as part of its response to the NRC's GSI-191 issue. The applicant reiterated that the aging effects of the liner plate are managed by the containment inservice inspection program per IWE and the Appendix J Containment Leakage Rate Testing Program, and that protective coatings are not relied upon to manage the effects of aging of the liner. Therefore, the staff accepts the applicant's determination that the protective coating on the containment liner may be considered outside the scope of license renewal and not subject to AMR. The staff finds the response acceptable.

- With regard to Item (ix), the response stated that the reactor cavity seal ring has no license renewal intended function. The staff notes that the reactor cavity seal ring is a flood barrier (FLB) to preclude borated water leaks through the seal and thereby prevent accumulation of borated water in the gap between the reactor vessel and the primary shield wall, which could induce corrosion of the reactor vessel and its supports as well as cause degradation of the primary shield wall concrete. Considering the above, in a follow-up RAI dated May 12, 2008, the staff requested the applicant to provide justification for excluding the reactor cavity seal from the scope of license-renewal and from being subject to an AMR.

  In its response, dated June 11, 2008, the applicant stated that the reactor cavity seal ring is a nonsafety-related component and it has no license renewal intended function pursuant to 10 CFR 54.4(a). Therefore, the reactor cavity seal is not within the scope of license renewal nor subject to AMR. The applicant specifically explained that the reactor cavity seal ring is installed prior to filling the refueling cavity to allow for fuel handling operations and that plant procedures ensure proper installation to preclude leakage during refueling operations. The applicant added that, even if the seal were to leak during the time the refueling cavity is filled, sump pumps in the cavity beneath the reactor vessel would prevent water accumulation in the gap between the reactor vessel and the primary shield wall.

The applicant further stated that plant operating experience does not indicate that leakage from the reactor cavity seal ring has caused corrosion of the reactor vessel or its supports; nor has it caused degradation of primary shield wall concrete. Further, aging management programs shown in LRA Tables 3.1.2-1 and 3.5.2-1 will manage the effects of aging from corrosion, if any, of the reactor vessel and its supports and will manage degradation of the interior concrete walls from exposure to borated water leakage during refueling.

Based on the above response, the staff understands that the reactor cavity seal is a nonsafety-related component installed during each refueling outage prior to flooding of the reactor cavity for refueling operations using procedures to ensure a leaktight installation. Also, the applicant's operating experience has not indicated any degradation of the reactor vessel, its supports, and the primary shield wall attributable to leakage through the reactor cavity seal. Further, the applicant has procedures/programs in place to manage any effects even if the seal were to leak during refueling operations. Therefore, the staff accepts the applicant's determination that the seal does not perform a license renewal intended function pursuant to 10 CFR 54.4(a) and, therefore, the reactor cavity seal is not in scope of license renewal nor subject to AMR. The applicant's response resolved the staff's concern.

Based on the discussion above of the applicant's clarifying responses, the staff finds the applicant's response to RAI 2.4.1-2 acceptable.

In RAI 2.4.1-3, dated January 28, 2008, the staff requested that the applicant confirm whether the component identified as "Structural Steel: beams, columns, plates, trusses" in LRA Table 2.4-1 includes bracings, welds, and bolted connections. The applicant also was requested to confirm whether the pressurized channel shrouds used at liner welded joints (including those at penetrations) are included in a structure/commodity group, or to justify their exclusion from an AMR. In addition, the applicant was requested to confirm whether the components identified as "bellows penetrations" in LRA Table 2.4-1 include the refueling bellows, if refueling bellows are used at IP2 and IP3.

In its response, dated February 27, 2008, the applicant stated that the component identified as "Structural Steel: beams, columns, plates, trusses" in LRA Table 2.4-1 includes bracing and welds associated with the component. The applicant further clarified that bolted connections for structures/components are addressed in LRA section 2.4.4 and Table 2.4-4. The applicant stated that the pressurized channel shrouds associated with liner welded joints (including those at penetrations) are not addressed as a separate component group. They are considered integral to the components listed as "liner plate and integral attachments" and "Electrical penetration sleeves" and "Mechanical penetration sleeves" in LRA Table 2.4-1. The applicant stated that components identified as "bellows penetrations" in LRA Table 2.4-1 do not include "refueling bellows." The applicant further clarified that bellows penetrations in LRA Table 2.4-1 are associated with containment piping penetrations and that refueling bellows are not a feature of the IP2 or IP3 design.

The staff finds that the applicant's response adequately addressed the staff's questions with regard to the stated components and, the response to RAI 2.4.1-3 is acceptable, subject to resolution of the additional clarifications requested below with regard to bellows. With regard to bellows penetrations, the applicant's response stated that the bellows penetrations in LRA Table 2.4-1 are associated with containment piping penetrations and that refueling bellows are not a feature of the IP2 or IP3 design. In the follow-up RAI dated May 12, 2008, the staff requested the applicant to further describe the types of piping penetration bellows in each unit. Also, the staff requested the applicant to clarify if there are transfer canal bellows (with the number in each unit) at Indian Point and if they are in-scope of license renewal or not, with justification.

In its response, dated June 11, 2008, the applicant stated that IP2 and IP3 containment penetrations consist of a sleeve embedded in the concrete and welded to the containment liner. The applicant explained that differential expansion between a sleeve and one or more hot pipes passing through it is accommodated by using a nickel alloy or stainless steel bellows-type expansion joint between the outer end of the sleeve and the piping outside of the containment wall. The applicant added that details of the containment penetrations and bellows for each unit are shown in UFSAR Figures 5.1-30 (IP2) and 5.1-12 (IP3).

The applicant stated that, for each unit, a fuel transfer tube is provided for fuel movement between the refueling transfer canal in the reactor containment and the spent fuel pit. The fuel transfer tube consists of a 20-in. stainless steel pipe installed inside a 24-in. pipe. The applicant added that two bellows-type expansion joints (one inside containment and one in the spent fuel pit) are provided on the tubes to compensate for any differential movement between the two pipes and other structures. Figure 5.1-31 of IP2 UFSAR and Figure 5.1-14 of IP3 UFSAR show details of the fuel transfer tube and bellows for each unit. These penetration bellows are within the scope of license renewal and subject to an AMR. They are listed as "bellows penetration" in LRA Tables 2.4-1 and 3.5.2-1.

In its above response, the applicant confirmed that, in addition to the piping penetrations bellows, the two fuel transfer tube bellows for each unit were in scope of license renewal and subject to AMR and were included as part of line item "bellows penetration" in LRA Table 2.4-1. The staff finds that the response addressed the staff's question with regard to the types of bellows that were scoped and screened for license renewal. Therefore, the response is acceptable.

During its review of components listed as "Polar Crane, rails and girders" and "Manipulator Crane, crane rails and girders" in LRA Table 2.4-1, the staff determined that additional information was needed to complete its review. In RAI 2.4.1-4, dated January 28, 2008, the staff requested that the applicant confirm whether the column structure; bridge and trolley of the polar crane; and the bridge, trolley and mast of the manipulator crane were screened-in as subject to an AMR. The staff also requested that the applicant confirm whether fasteners and rail hardware associated with the polar crane and manipulator crane are within scope of license renewal and subject to an AMR; and if they were excluded, the staff requested that the applicant provide a justification. The staff also requested that the applicant indicate whether there were any other hoists and lifting devices (e.g. for the reactor vessel head and reactor internals) that should be included as components within the scope of license renewal and subject to an AMR; and if so, the staff requested that the applicant provide scoping, screening, and AMR results relevant to the LRA.

In its response, dated February 27, 2008, the applicant stated that the column structure; bridge and trolley of the polar crane; and the bridge, trolley and mast of the manipulator crane are screened-in as subject to an AMR. The applicant indicated that these components are subparts of “crane, rails and girders.” The applicant stated that fasteners (“structural bolting”) and rail hardware (“component support”) associated with the polar crane and manipulator crane are within the scope of license renewal and subject to an AMR. The applicant indicated that these components are addressed in LRA Section 2.4.4, “Bulk Commodities.” The applicant clarified that there were no hoists or lifting devices, other than those already identified in the LRA, that perform a license renewal intended function.

Because the applicant stated that the structures and components in question are subject to an AMR, the staff finds that the applicant adequately addressed the staff’s questions; therefore, the response to RAI 2.4.1-4 is acceptable. The staff’s concern described in RAI 2.4.1-4 is resolved.

Because of a lack of clarity in LRA Table 2.4-1 regarding components listed as Equipment Hatch and Personnel Lock, in RAI 2.4.1-5, dated January 28, 2008, the staff requested that the applicant clarify whether the flange double-gaskets, hatch locks, hinges, and closure mechanisms that help prevent loss of sealing/leak-tightness for these listed hatches were included within the scope of license renewal and subject to an AMR. The staff also requested that the applicant provide scoping, screening, and AMR results as appropriate or justify their exclusion.

In its response, dated February 27, 2008, the applicant stated that the flange double-gaskets, hatch locks, hinges, and closure mechanisms for the equipment hatch and personnel lock are within the scope of license renewal. The applicant clarified that the double gasket seals are included under the line item “equipment hatch and personnel lock seal” in LRA Table 2.4-1, and are subject to AMR. The AMR results are provided in Table 3.5.2-1. The applicant stated that hatch locks, hinges, and closure mechanisms are active components and are, therefore, not subject to aging management review as discussed in LRA Table 3.5.1, Line Item 3.5.1-17. The applicant added that satisfactory performance of these active components is demonstrated through routine testing under the Containment Leak Rate Program as required by Section 3.6.2 of the IP2 and IP3 Technical Specifications.

The staff finds that the applicant has adequately addressed the staff’s concern with regard to the flange double-gaskets for the hatches in question. However, the response stated that the hatch locks, hinges, and closure mechanisms are active components and, therefore, not subject to AMR as discussed in LRA Table 3.5.1, Line Item 3.5.1-17. The staff noted that these components are passive during plant operation, during which time they are (and need to remain) in a closed position and are an integral part of the pressure boundary. Considering the above, in a follow-up RAI, dated May 12, 2008, the staff requested the applicant to provide the justification for excluding the hatch locks, hinges, and closure mechanisms from the scope of license-renewal and from being subject to an AMR.

In its response, dated June 11, 2008, the applicant stated that the IP2 and IP3 hatch locks, hinges, and closure mechanisms are in scope of license renewal. However, since they perform their functions with moving parts or change in configuration, they are not subject to AMR. The applicant added that consistent with NUREG 1801, Volume 1, Revision 1, Table 5, Item 17, their leaktightness in the closed position is demonstrated through routine testing under the containment leakage rate test program as required by IP2 and IP3 Technical Specifications (Reference LRA Table 3.5.1, Line Item 3.5.1-17). Since the applicant's response clarified that, in the closed position, the hatch locks, hinges, and closure mechanisms are considered integral to the hatch itself, whose leaktightness is demonstrated by routine local leak rate testing under the Containment Leakage Rate Test Program, the staff finds the response acceptable.

2.4.1.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI and follow-up RAI responses to determine whether the applicant failed to identify any SCs within the scope of license renewal. The staff found no omissions. In addition, the staff sought to determine if the applicant failed to identify any SCs subject to an AMR. The staff found no omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the containment buildings SCs within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.2 Water Control Structures

2.4.2.1 Summary of Technical Information in the Application

LRA Section 2.4.2 describes the water control structures, which include:

- discharge canal and outfall structure
- intake structure (IP1, IP2, IP3) and intake structure enclosure building (IP3)
- service water pipe chase (IP3)
- service water valve pit (IP2 and IP3)

The discharge canal and outfall structure, located west of the IP2 and IP3 turbine buildings, extends from the IP1 turbine building and carries SW system discharge to the river. Three IP3 backup SW pumps, which provide cooling water from the discharge canal in the unlikely event of damage to the SW intake structure, are supported on a slab spanning the walls of the canal. The SW pipe chase, a concrete structure enclosing the SW line, spans across the discharge canal. The discharge canal wall portion adjacent to the SW pipe chase is seismic Class I and part of the ultimate heat sink. The outfall structure enhances mixing of cooling water and river water to minimize thermal impact on the river. The discharge port gates can be adjusted mechanically to control fluid discharge velocity. The outfall structure does not support a license renewal function as defined by 10 CFR 54.4 and hence is not in the scope of license renewal.

The IP1 intake structure (also known as the screenwell house) is a seismic Class III structure located adjacent to the wharf and west of the station on the riverbank. It houses electrical components required for the alternate safe shutdown system, which is credited in the Appendix R safe shutdown analysis. The lower portion contains the IP1 intake, which houses the river water pumps that support IP2 SW. The structure is a reinforced concrete frame supported by a massive concrete substructure. Exterior walls of the intake structure are of concrete brick construction. The north and south ends of the structure are covered by a reinforced concrete roof slab.

The IP2 intake structure (also known as the screenwell structure) is west of the site, below grade at the Hudson River bank, and is open to the river on the west side. The IP3 intake structure (also known as the screenwell structure) is west of the containment structure. Each structure houses six CW pumps (each in a separate reinforced concrete compartment), six SW pumps (a SW bay enclosure protects the IP3 pumps), traveling and fixed screens, and screen wash equipment. On the east side of each structure, the SW strainer pit houses SW strainers, screen wash piping, and the strainer control panel. Both the SW strainer pit and the SW bay enclosure are seismic Class I.

The intake structure enclosure building located west of the containment structure provides an upper separate enclosure for the IP3 intake structure and protects CW and SW system components from the weather. Dampers located in the roof system release excess heat during normal operations. The intake structure enclosure consists of a single story steel-framed super-structure with exterior metal siding and ventilation panels.

The IP3 SW pipe chase, which protects SW lines that span the discharge canal and the SW valves and piping, is a reinforced concrete structure attached to the discharge canal wall. The discharge canal wall portion adjacent to the SW pipe chase is seismic Class I.

SW valve pits at the west side of the IP2 and IP3 heater bay buildings protect SW components in IP2 and IP3 intake structures. IP3 has an additional SW valve pit on the north end of the IP3 heater bay building to back up the SW pumps. The SW valve pits are underground reinforced concrete structures covered by structural steel plate welded to I-beams at ground level. The additional SW valve pit for IP3 has a precast concrete roof.

The water control structures contain safety-related components relied upon to remain functional during and following DBEs. The failure of nonsafety-related SSCs in the water control structures potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the water control structures perform functions that support fire protection.

LRA Table 2.4-2 identifies water control structures component types, grouped by material (steel/other metals, concrete), within the scope of license renewal and subject to an AMR as well as their intended functions.

2.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.4.2 and UFSAR Section 8.3 for IP2 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4.

During its review, the staff evaluated the structural component functions described in the LRA and UFSAR to verify that the applicant had not omitted from the scope of license renewal any SCs with intended functions, as required by 10 CFR 54.4(a). The staff then reviewed those SCs that the applicant identified as within the scope of license renewal to verify that the applicant had 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 2.4.2, the staff identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

In RAI 2.4.2-1, dated January 28, 2008, the staff noted that LRA Table 2.4-2 does not include the debris wall, fixed coarse screens, fine mesh traveling screens, and gates at the intake structure. Further, the table does not include metal decking, metal siding, grating, and ventilation panels for the intake structure enclosure; nor does it include manhole, ladder, and sump of the SW valve pit. The staff requested that the applicant confirm whether or not these components should be included within the scope of license renewal and subject to an AMR and, if so, to provide scoping, screening and AMR results. If not, the staff requested the applicant to justify their absence from LRA Table 2.4-2. The applicant also was requested to clarify whether the "structural steel" component in LRA Table 2.4- 2 includes, among other items, beams, plates, and welded/bolted connections.

In its response, dated February 27, 2008, the applicant stated that the debris wall, fixed coarse screens, fine mesh traveling screens, and gates at the intake structure are not safety-related and are not required to demonstrate compliance with 10 CFR 54.4(a)(3). The applicant stated that the system design is such that failure of these components will not prevent satisfactory accomplishment of a safety function. However, their support structures, being integral to the intake structure in some cases (e.g., embedded guides and steel supports), are included in the "structural steel" category listed in LRA Table 2.4.2. The applicant stated that metal siding for the intake structure enclosure is not safety-related and is not required to demonstrate compliance with 10 CFR 54.4(a)(3). The applicant added that failure of the metal siding component will not prevent satisfactory accomplishment of any safety function. The applicant stated that in-scope grating, decking, and ladders are bulk commodities addressed in LRA Table 2.4-4. The ventilation panels for the intake structure enclosure are addressed as "vents and louvers" and listed in LRA Table 2.4-4. Furthermore, the applicant stated that manholes are included in LRA Table 2.4-3. The sump of the SW valve pit is integral to the in-scope SW valve pit; thus, it is not listed as a separate item. The applicant clarified that the "structural steel" component type in LRA Table 2.4-2 includes columns, beams, plates, and their welded connections. Structural bolting is included as a bulk commodity and listed in LRA Table 2.4-4.

In reviewing the response to RAI 2.4.2-1, the staff also reviewed the discussion on the "Service Water System" and "Tornado Design Criteria" in Sections 9.6.1 and 16.2, respectively, of the IP3 UFSAR. Based on the description in these UFSAR sections, the SW supply is assured by redundancy of two supply lines, four intakes and screens, and six pumps, of which only two pumps, one intake and screen, and one supply line are required for prolonged shut-down. Further, the backup SW system provides an additional source of service water independent of the intake structure. The existence of these redundancies in the SW system confirms the applicant's statement, in the RAI response, that failure of the intake structure components noted in the RAI, which are part of the SW system, will not prevent satisfactory accomplishment of the safety function of the SW system. However, in the response, the applicant stated that in-scope grating, decking, and ladders are bulk commodities addressed in LRA Table 2.4-4. Since this is a generic statement, in a follow-up RAI, dated May 12, 2008, the staff requested the applicant to clarify if the specific components in question that were identified in the RAI (i.e. metal decking and grating of the intake structure enclosure and ladder of the service water valve pit) are included in the scope of license renewal, and subject to AMR as bulk-commodities addressed in LRA Table 2.4-4.

In its response, dated June 11, 2008, the applicant stated that metal decking and grating of the intake structure enclosure and ladder of the service water valve pit have license renewal intended functions as defined by 10 CFR 54.4(a)(2) and, therefore, they are in scope of license renewal and subject to an AMR. The applicant added that these structural components are included in LRA Table 2.4-4, line item "Stairway, handrail, platform, grating, decking, and ladders." Since the applicant explicitly clarified that the specific structural components identified in the RAI were subject to an AMR, the staff finds the response acceptable.

Based on the above response to RAI 2.4.2-1 and to the follow-up RAI, and the descriptions in Section 9.6.1 and Section 16.2 of the IP3 UFSAR, the staff finds that the applicant has adequately addressed and/or clarified the scoping and screening of the specific structural components identified in the RAI. Therefore, the applicant's response to RAI 2.4.2-1 is acceptable.

The staff also requested additional information in RAI 2.4.2-2, dated May 12, 2008, regarding other structural components. In Part (a) of RAI 2.4.2-2, the staff noted that LRA Table 2.2-3 and LRA Section 2.4.2 include "discharge canal and outfall structure" as being within the scope of license renewal. The description in LRA Section 2.4.2, in the second paragraph under the subtitle "Discharge Canal and Outfall Structure," states that the outfall structure does not support a license renewal function and, therefore, is not in scope. The staff requested the applicant to explain why the "outfall structure" was included in LRA Table 2.2-3 and LRA Section 2.4.2. The staff requested the applicant to discuss this inconsistency and take appropriate action in scoping the outfall structure.

In Part (b) of RAI 2.4.2-2, because of a lack of clarity in the description in LRA Section 2.4.2 with regard to the discharge canal, the staff requested the applicant to confirm/clarify if (i) the entire discharge canal is considered within the scope of license renewal and subject to AMR <u>or</u> (ii) only the portion adjacent to/supporting the service water pipe chase, and the portion supporting and including the slab on which the Unit 3 service water backup pumps are mounted, are within the scope of license renewal and subject to an AMR.

In its response to Part (a) of RAI 2.4.2-2, dated June 11, 2008, the applicant stated that the "outfall structure" is included in LRA Table 2.2-3 and LRA Section 2.4.2 as part of line item "discharge canal and outfall structure" because this line item is the name of one continuous structure that includes the discharge canal and the outfall structure. The only portion that is within the scope of license renewal is the discharge canal. The applicant reiterated that the description in LRA Section 2.4.2, in the second paragraph under the subtitle "Discharge Canal and Outfall Structure," states that "[t]he outfall structure does not support a license renewal function as defined by 10 CFR 54.4 and, therefore, is not in scope." The applicant added that this statement specifically addresses exclusion of the outfall structure portion of the structure from the scope of license renewal and AMR. The staff finds the response acceptable because the applicant clarified that only the discharge canal is within the scope of license renewal; the outfall structure portion of the "discharge canal and outfall structure" is not within the scope of license renewal.

In its response to Part (b) of RAI 2.4.2-2, dated June 11, 2008, the applicant stated that the entire discharge canal is within the scope of license renewal and subject to AMR. Since the response clarified that the entire discharge canal is conservatively included as being in scope of license renewal and subject to AMR, the staff finds the clarification provided by the applicant acceptable.

2.4.2.3 Conclusion

The staff reviewed the LRA, UFSAR, RAI and follow-up RAI responses, and description of related structural components to determine whether the applicant failed to identify any SCs within the scope of license renewal. The staff found no omissions. In addition, the staff sought to determine if the applicant failed to identify any SCs subject to an AMR. Again, the staff found no omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the water control structures SCs within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.3 Turbine Buildings, Auxiliary Buildings, and Other Structures

2.4.3.1 Summary of Technical Information in the Application

LRA Section 2.4.3 describes the turbine buildings, auxiliary buildings, and other structures:

- Appendix R diesel generator foundation, fuel oil tank vault, switchgear and enclosure (IP3)
- auxiliary feedwater pump building (IP2, IP3)
- boric acid evaporator building (IP2)
- city water storage tank foundation and meter house
- condensate storage tanks foundation (IP2, IP3)
- containment access facility and annex (IP3)
- control buildings (IP2, IP3)
- diesel generator buildings (IP2, IP3)
- electrical tunnels (IP2, IP3)
- emergency lighting poles and foundations
- fan houses (IP2, IP3)
- fire pump house (IP2)/fire protection pump house (IP3)
- fire water storage tank foundation (IP2, IP3)
- fuel storage buildings (IP2, IP3)
- gas turbine generator Nos. 1, 2, and 3 enclosure and fuel tank foundation (includes gas turbine substation switchgear structures and foundation)
- maintenance and outage building elevated passageway (IP2)
- manholes and duct banks
- new station security building
- nuclear service building (IP1)
- power conversion equipment building (IP3)
- PABs (IP2, IP3)
- primary water storage tanks foundation (IP2, IP3)
- radiation monitoring enclosure (IP2)
- refueling water storage tanks foundation (IP2, IP3)
- security access and office building (IP3)
- superheater building (IP1)

- superheater stack (IP1)
- transformer/switchyard support structures
- transmission towers (SBO recovery path) and foundations
- turbine building (IP1, IP2, IP3) and heater bay (IP2, IP3)
- utility tunnel
- waste holdup tank pit (IP2, IP3)

The Appendix R diesel generator, fuel oil tank vault, and switchgear are located in separate, adjacent enclosures in the yard area north of the AFW pump room. The Appendix R diesel generator, fuel oil tank vault, and switchgear support a power supply sufficient to allow the plant to be brought to cold shutdown in a loss of offsite power coincident with a fire causing the loss of all three EDGs or their distribution systems.

The IP2 AFW pump building in the shield wall area between the shield wall and the IP2 containment building is a seismic Class I structure that protect the Class I AFW pumps. The MS lines also located in this building are supported by the structural steel framing.

The IP3 AFW pump building in the shield wall area between the shield wall and the IP3 containment building also includes the shield wall area enclosure. It is a seismic Class I structure that protects the Class I AFW pumps and MS lines located in this area.

The boric acid evaporator building is a seismic Class I reinforced concrete structure supported by the roof slab of the IP2 waste hold-up tank pit. The exterior walls are of concrete and concrete block construction. Portions of the concrete walls are removable. Over the concrete block portion is light-weight roofing over metal decking and over the concrete walls is a concrete slab.

The city water storage tank and meter house is a source of water for the AFW system for both IP2 and IP3 and of emergency water for SI, RHR, and charging pumps. The city water storage tank foundation supports the storage tank safety function. The meter house shelters and protects the storage tank components. A free-standing, 1,500,000-gallon vertically cylindrical carbon steel city water storage tank is supported by a reinforced concrete spread footing foundation on rock. The meter house is a single-story concrete brick and steel structure with a concrete roof slab.

Two separate reinforced concrete slab foundations support the condensate storage tanks for IP2 and IP3.

The containment access facility and annex adjacent to the PAB is a handling area for contaminated material and a personnel access to containment. The containment access facility and annex is Class III except for the seismic Class I structural steel portion interfacing with the PAB. The containment access facility and annex has structural steel framing supported on the PAB roof floor slab and insulated metal siding.

The control buildings house the central control room, cable spreading room, and other safety-related equipment and components. The IP2 control building adjacent to the IP2 turbine building on the west and the superheater building on the south contains both the IP1 and IP2 control rooms. It is a multi-story Class I steel framed structure with north and east exterior walls of insulated metal-sandwich panels. Floor slabs are composite-type construction, concrete over steel beam. The IP3 control building is a multi-story Class I concrete structure with concrete and concrete brick exterior is adjacent to the IP3 turbine building on one end and the diesel generator building on the south. Both structures are founded on bedrock.

The seismic Class I IP2 diesel generator building consists of a reinforced concrete foundation on bedrock, a prefabricated rigid steel superstructure with exterior insulated metal siding, and a solid, corrugated metal roof. The diesel generators rest on reinforced concrete foundations supported by the structure's main slab. A concrete shield wall on the west side serves as missile protection between the control panel and diesels. The IP3 diesel generator building is a single-story reinforced concrete structure on a concrete slab supported on bedrock. Each diesel generator building houses three safety-related diesel generators. Each diesel has separate underground storage vaults, integral to its building, for fuel oil tanks. Foundations for the fuel oil tanks are the same as for the structure.

The electrical tunnels are partially below-grade, seismic Class I reinforced concrete structures that contain electrical cable, conduit, and cable trays that support plant operations. The IP2 electrical tunnel running eastward from the east side of the control building is attached to the south side of an east-west retaining wall. The elevation of the lower slab of the tunnel slopes from the control building up to the PAB. The tunnel then turns northward past the west side of the PAB to the electrical penetration area adjacent to the IP2 containment building. The IP3 electrical tunnels run from the control building past the PAB to the containment penetration vault. The electrical tunnels consist of two seismic Class I reinforced concrete conduits, one above the other. Both the upper and lower tunnels are eight feet wide by eight feet high.

Pole-mounted security lighting around the perimeter of the plant site provides emergency lighting in an Appendix R fire and a loss of offsite power by illuminating ingress and egress. Each emergency light pole is a single-pole steel structure supported by a reinforced concrete foundation.

Each fan house is a seismic Class I structure containing the piping penetration area. Safety-related valves in the piping penetration area may be used to achieve safe shutdown. Each fan house building is a multi-story reinforced concrete and masonry block wall structure founded on bedrock. A steel superstructure on top of each building supports the roof framing system. The IP2 fan house southeast of the IP2 containment structure and between the IP2 containment, the IP2 PAB, and the IP2 fuel storage building is isolated from the containment structure and the PAB. Its east wall is common with the west wall of the fuel storage building. The IP3 fan house southeast of the IP3 containment structure and between the IP3 containment, the IP3 PAB, containment access facility, and the IP3 fuel storage building is isolated from the containment structure and the PAB. Its east wall is common with the west wall of the fuel storage building and its south wall is common to the containment access facility annex.

The IP2 fire protection pump house (also known as diesel fire pump house) houses the main diesel firewater pump and protects fire protection system components. The structure is of structural steel framing with exterior insulated metal siding and a composite metal roof. The foundation is a reinforced concrete slab on grade. The IP3 fire protection pump house contains the electric motor-driven fire pump, the diesel-driven fire pump, and equipment for an adequate source of fire water. The structure is a reinforced concrete and concrete block wall construction with a concrete roof slab. The foundation is a reinforced concrete slab on bedrock.

The IP2 fire water storage tank (also known as suction tank) foundation is the main support for the 300,000-gallon fire water storage tank. Water for the dedicated diesel-driven fire pump for normal operations comes from the tank. The IP3 fire water storage tank foundations are the main supports for two 350,000-gallon fire water storage tanks. The tanks and their piping, electrical, and instrumentation systems are the source of fire protection system water and IP3 makeup water treatment.

For IP2 and IP3, the fuel storage building is designed to handle and store both spent and new fuel and supports the spent fuel crane and other fuel-handling equipment. In addition, the floor of IP2 provides support for a single-failure-proof gantry crane. Each structure is located adjacent to but separate from its containment building.

The gas turbine generator No. 1 enclosure and tank foundation are seismic Class III structures providing shelter and protection from the elements for gas turbine No. 1 and its associated equipment. Gas turbine No. 1 is located adjacent to the Unit 1 turbine building and supports no license renewal function; however, the associated switchgear components and fuel supply tank provide support for the SBO/Appendix R diesel generator set. The gas turbine No. 1 enclosure consists of structural steel framing with exterior metal siding on a reinforced concrete slab. The fuel tank foundation is a reinforced concrete spread footing which supports the fuel tank supplying the SBO/Appendix R diesel.

The gas turbine generators Nos. 2 and 3 enclosure is a seismic Class III structure that shelters and protects the equipment from the elements. The gas turbine Nos. 2 and 3 enclosure located at the Buchanan substation houses gas turbine generators Nos. 2 and 3 and their switchgear equipment. The switchgear and associated components within the structure support offsite power recovery following station blackout. The gas turbine Nos. 2 and 3 fuel tank foundation supports the fuel tank, an alternate source of EDG fuel. These fuel tanks shared by IP2 and IP3 are credited for minimum EDG fuel oil inventory. If the EDGs require the reserves in these tanks, the contents can be transported by tanker truck.

The gas turbine substation switchgear structures and foundation support equipments required to support offsite power recovery following station blackout. It consists of a reinforced concrete slab that supports the substation and switchgear support structures. Component equipment is anchored by welding or bolting to embedments in the concrete slab.

The maintenance and outage building and elevated passageway are seismic Class II structures used by maintenance and outage personnel. The structures are southeast of the IP2 containment structure, across from the PAB, and adjacent to the fuel storage building. The building has two major floors and an elevated passageway for access to the PAB. A safety-related conduit routed through one end of the building near the bridge connects the maintenance and outage building to the PAB.

Manholes and duct banks throughout the applicant's yard allow underground routing of cables and piping. These structural components are of reinforced and non-reinforced concrete.

The new station security building east of the IP1 containment structure provides offices for personnel and contains the security generator credited as a source of backup power to the station security lighting system. For IP2, this lighting illuminates exterior ingress and egress in an Appendix R fire and a loss of offsite power.

The IP1 nuclear service building adjacent to but separated from the IP1 containment structure protects alternate safe shutdown system components in support of IP2. These components consist of cables in conduit for various systems: chemical and volume control, CCW, RHR, and SI systems. The structure contains treatment and decontamination facilities and examination rooms for site personnel.

The IP3 power conversion equipment building houses power conversion system components.

The IP2 PAB is a seismic Class I structure housing safety injection pumps, component cooling pumps, heat exchangers, and RHR pumps. The IP3 PAB houses components required for recirculation (*e.g.*, component cooling pumps, heat exchangers, and SI and RHR pumps).

The IP2 and IP3 primary water storage tank foundations are the main supports for the 165,000-gallon primary water storage tank for each unit. The tanks supply demineralized water for the primary water makeup systems.

The IP2 radiation monitoring enclosure houses radiation monitors R46, R49 and R53. Monitors R46 and R53 monitor the SW return from all containment fan cooler units.

For both IP2 and IP3, the RWST foundation is the main support for the 350,000-gallon RWST. The tank supplies borated water to the refueling canal, SI pumps, RHR pumps, and the containment spray pumps for a LOCA.

The IP3 security access and office building located west of the service admin complex provides offices for personnel and contains the security generator credited as a source of backup power to the station security lighting system. For IP3, this lighting illuminates exterior ingress and egress in an Appendix R fire or a loss of offsite power.

The IP1 superheater building is adjacent to but physically separated from the control building. The superheater stack is located on top of the superheater building. The structure contains the technical support center, provides office area for personnel, supports alternate safe shutdown system components, and houses a safety-related battery room.

The IP1 superheater stack on top of the superheater building carries exhaust from the superheaters and also supports a ventilation duct carrying exhaust from the containment structure. Failure of the stack could result in damage to the IP2 control building, the EDG building, and in-scope IP3 structures. To minimize this risk, the applicant shortened the stack and reinforced its support structure to satisfy IP3 tornado protection criteria.

The offsite power source required to support SBO recovery actions is fed through one of the station auxiliary transformers. Specifically, the path includes the 138kV and 345kV switchyard circuit breakers feeding either station auxiliary transformers.

The transformer/switchyard support structures physically support the station auxiliary transformers and the other switchyard components in the SBO recovery path. These support structures include the transformer foundations and support steel, transformer pothead foundations and support steel, and switchyard breaker foundations.

Transmission towers (SBO recovery path) and foundations are parts of the path to restore offsite power.

The IP1 turbine building is an extension of the IP2 turbine building and is integrally attached to the superheater building and the IP2 turbine building. The structure is classified as seismic Class III but was analyzed to ensure that there is no potential for gross structural collapse as a result of a design basis event. Equipment and components on the IP1 operating floor have been removed and the supporting systems for these components are not in service. The facility houses the station blackout/Appendix R diesel and two fire water pumps, along with their associated components relied upon in the site's safe shutdown analysis. The building is constructed of heavy structural steel framing with steel supported reinforced concrete slabs forming the floor area. Crane rails located within IP1 extending the entire length of the structure also provide support for IP2. The building's exterior face is constructed of metal-sandwich panels and concrete brick.

The IP2 turbine building and heater bay extension of the IP1 turbine building is similar to IP1 and is seismic Class III. Although the turbine building and heater bay are seismic Class III structures, they were analyzed for potential gross structural collapse as a result of a design-basis event. Attached to the superheater building and the IP1 turbine building, the building houses the IP2 turbine generator, FW heaters, and their supporting systems as well as cabling, switchgear, and other SBO/Appendix R diesel equipment.

The IP3 turbine building and heater bay is a seismic Class III structure that houses the turbine generator and its auxiliaries. The structure is designed not to affect Class I structures.

The utility tunnel is a seismic Class III structure. The tunnel shelters and protects the city water supply piping for AFW backup water and other miscellaneous functions. The utility tunnel is a rectangular reinforced concrete structure founded on rock.

The IP2 waste holdup tank pit is adjacent to the refueling water tank and its top slab supports the boric acid evaporator building. The IP3 waste holdup tank pit, two structures joined to form a single structure, is adjacent to the primary water storage tank and the radioactive machine shop. The waste holdup tank pits house liquid waste holdup tanks which are the collection points for liquid radwaste. A sump services the water tanks.

The turbine buildings, auxiliary buildings, and other structures contain safety-related components relied upon to remain functional during and following DBEs. The failure of nonsafety-related SSCs in the turbine buildings, auxiliary buildings, and other structures potentially could prevent the satisfactory accomplishment of a safety-related function. In addition, the turbine buildings, auxiliary buildings, and other structures perform functions that support fire protection and SBO.

LRA Table 2.4-3 identifies turbine buildings, auxiliary buildings, and other structure component types, grouped by material (steel/other metals, concrete), within the scope of license renewal and subject to an AMR as well as their intended functions.

2.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.4.3 and IP2 UFSAR Sections 1.3.8, 1.11.4.12, 1.11.6, 7.2.4.1.4, and 9.5.2, and IP3 UFSAR Sections 8.4, 9.6.2, 9.6.2.9, and 11.1.2.1, using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4.

During its review, the staff evaluated the structural component functions described in the LRA and UFSAR to verify that the applicant had not omitted from the scope of license renewal any SCs with intended functions, as required by 10 CFR 54.4(a). The staff then reviewed those SCs that the applicant identified as within the scope of license renewal to verify that the applicant had 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 2.4.3, the staff identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

In the second part of RAI 2.4-1, dated January 28, 2008 (the first part of RAI 2.4-1 is addressed in SER Section 2.4), the staff noted that the structure identified as "Gas Turbine Substation Switchgear Structures and Foundation" in LRA Table 2.2-3 was not included in the structures listed at the beginning of the subsection "Description" of LRA Section 2.4.3. The staff requested that the applicant address the scoping and screening of these structures or clarify where they were addressed in the LRA.

In the last paragraph of its response to RAI 2.4-1, dated February 27, 2008, the applicant stated that the "Gas Turbine Substation Switchgear Structures and Foundation" area is addressed in LRA Section 2.4.3, subsection titled "Description" under "Gas Turbine Generator No. 1, 2 and 3 Enclosure and Fuel Tank Foundation." The staff verified that a description of switchgear structures and foundation was included in the subsection in Section 2.4.3 describing the gas turbine generators No. 1, 2 and 3 enclosure and fuel tank foundations, as stated by the applicant. The staff finds the applicant's response acceptable subject to further clarification as requested in the follow-up RAI, dated May 12, 2008.

Because of a lack of clarity in LRA Table 2.4-3, and the applicant's response to RAI 2.4-1 with regard to switchgear structures and foundation, the staff sought clarification regarding which specific structural components in Table 2.4-3 cover the switchgear structures and foundation. The staff noted that the component line item "foundations" in LRA Table 2.4-3 does not list "switchgear structures" in the structure list provided within parenthesis.

In its response, dated June 11, 2008, the applicant stated that the switchgear foundation is listed in LRA Table 2.4-4, as equipment pads/foundations. Since the applicant clarified that the switchgear foundations are included as a concrete bulk commodity item as part of line item "equipment pads/foundation" in LRA Table 2.4-4, and the embedments to which the switchgear equipment is anchored are included as part of bulk commodity line item "anchorages/embedments" in LRA Table 2.4-4, the staff finds the response acceptable.

In RAI 2.4.3-1, dated January 28, 2008, the staff noticed the following in the LRA with regard to the fuel storage buildings:

(i) LRA Section 2.4.3 states that the fuel storage buildings have the following intended functions pursuant to 10 CFR 54.4(a)(1) and (a)(2): "Maintain integrity of nonsafety-related components such that safety functions are not affected by maintaining pool water inventory (Units 2 and 3)."

(ii) LRA Section 2.1.2.2, "Screening of Structures," states that the screening of structural components and commodities was based primarily on whether they perform an intended function.

(iii) LRA Table 3.5.2-3, “Turbine Building, Auxiliary Building, and Other Structures, Structural Components and Commodities (IP2 and IP3),” identifies structural components subject to aging management based on materials of construction and intended functions for components of structures, including the fuel storage buildings.

(iv) The intended functions listed in LRA Table 3.5.2-3 (e.g., pressure boundary, missile barrier, and shelter or protection) agree with the intended functions listed in LRA Table 2.0-1, “Intended Functions: Abbreviations and Definitions.” However, the intended functions for the fuel storage building listed in LRA Section 2.4.3 do not agree with the listed intended functions in LRA Tables 2.0-1 and 3.5.2-3.

With reference to the above, the staff noted in the RAI that, pursuant to 10 CFR Part 54.21, the LRA must identify and list those SCs subject to an AMR. The staff requested that the applicant clarify the LRA Section 2.4.3 description of the intended function(s) of the fuel storage building components, using the list of intended functions from LRA Table 2.0-1. The staff added that, to satisfy the requirements of 10 CFR Part 54.21, the clarification must be adequate to reasonably identify the fuel storage building structural components subject to an AMR by the component or commodity, material of construction, and intended functions listed in LRA Table 3.5.2-3.

In its response, dated February 27, 2008, as supplemented in LRA Amendment No. 3, dated March 24, 2008, the applicant stated that the intended functions listed in LRA Tables 2.0-1 and 3.5.2-3 are component intended functions, which are determined during the screening process. The intended functions in LRA Section 2.4.3, in contrast, are the intended functions of the structure in its entirety and are determined during the scoping process. The applicant explained that the scoping process determines whether or not the structure has an intended function (i.e., providing containment or isolation to mitigate post-accident offsite doses, or providing support or protection to safety-related equipment), whereas the screening process identifies those components that support the structure intended function(s) via specific component intended functions (i.e., providing shelter and protection or providing support for safety-related equipment). The structure and system level functions that are assessed against the scoping requirements of 10 CFR Part 54.4 are not intended to match the component level functions defined in LRA Table 2.0-1. While similarities exist between the terminology used for component intended functions versus structure intended functions, a direct correlation between the structure intended functions in LRA Section 2.4 and the component intended functions in the tables in LRA Section 3.5 does not exist. The applicant clarified that the structure level intended functions of the fuel storage buildings are to: (a) maintain integrity of nonsafety-related components such that safety functions are not affected by maintaining pool water inventory, and (b) provide support and protection for safety-related equipment within the scope of license renewal. The applicant also provided a tabulation of component level intended functions (as defined in LRA Table 2.0-1) supporting each of the two structure level intended functions for the fuel storage buildings.

In its response, the applicant used a broader structure level intended function concept in the scoping process and supplemented that by more detailed component level intended functions for the structural components during the screening process. Because the applicant 1) has clarified the structure level intended functions of the fuel storage buildings, and 2) provided a tabulation of the structural component intended functions for each of the two structure level intended functions (as defined in LRA Table 2.0-1), the staff finds the applicant’s response acceptable. Therefore, the staff’s concern described in RAI 2.4.3-1 is resolved.

In RAI 2.4.3-2, dated January 28, 2008, the staff noted that, in LRA Section 2.4.3, the top of the spent fuel pit wall forms the north wall of each unit's fuel building. The staff further noted that UFSAR Figure 1.2-4 (IP2), “Cross Section of Plant,” indicates that at least part of the fuel building exterior wall is below grade. LRA Table 2.4-3 lists pressure boundary as an intended function for the concrete component “exterior walls” but does not list pressure boundary as an intended function of the concrete component “exterior walls-below grade,” representing the fuel building wall. The staff requested that the applicant update LRA Table 2.4-3 to include the pressure boundary intended function for the spent fuel pit wall that is below grade or provide justification for excluding this intended function.

In its response, dated February 27, 2008, the applicant stated that it agrees that the spent fuel pit wall below grade also performs a pressure boundary intended function. The applicant revised LRA Tables 2.4-3 and 3.5.2-3 to include the pressure boundary intended function for exterior walls below-grade which includes the spent fuel pit wall. The staff finds the applicant’s response adequately addresses the staff’s concerns raised in the RAI and, therefore, is acceptable. The staff’s concern described in RAI 2.4.3-2 is resolved.

In RAI 2.4.3-3, dated January 28, 2008, the staff noted that LRA Table 2.4-3 does not include the leak chase channel of the IP3 spent fuel pit as a component subject to an AMR. The staff requested the applicant to include this as a component subject to an AMR or provide a justification for its exclusion.

In its response, dated February 27, 2008, the applicant stated that the leak chase channel is an integral attachment to the liner plate, which is subject to AMR and included in line item “Spent fuel pool liner plate and gate” in LRA Table 2.4-3. The staff agrees with the applicant’s position that the leak chase channel, which is welded to the liner plate, can be considered an integral attachment to the liner plate and included as part of the liner plate component. The staff finds the applicant’s response adequately addresses the staff’s concerns raised in the RAI and, therefore, is acceptable. The staff’s concern described in RAI 2.4.3-3 is resolved.

In RAI 2.4.3-4, dated January 28, 2008, the staff noted that, although LRA Table 2.4-3 lists “Crane rails and girders” as a component type subject to an AMR, it is not clear whether this component refers to just crane rails and girders or also refers to the cranes themselves. If it includes the cranes, the applicant was requested to clarify whether all relevant subcomponents (“...including bridge and trolley, rails, and girders”) of these in-scope crane systems have been screened in as items requiring an AMR. The staff also requested that the applicant identify the specific cranes in each of these structures that are included within the above component type as within the scope of license renewal and subject to an AMR, and those that are excluded, with technical bases. The applicant also was requested to confirm whether fasteners and rail hardware associated with this component type are within the scope of license renewal and subject to an AMR or provide the technical bases for their exclusion. The staff also requested that the applicant confirm whether there are other hoists and lifting devices that should be included within the scope of license renewal (and subject to an AMR) and, if so, provide their scoping, screening, and AMR results, relevant to the LRA.

In its response, dated February 27, 2008, the applicant stated that the component type “crane rails and girders” in LRA Table 2.4-3 includes bridge and trolley and also refers to the cranes themselves. The applicant further stated that there are no hoists or lifting devices that perform an intended function that would place them in scope and subject to an AMR. The applicant clarified that the specific cranes in scope and subject to an AMR are discussed in LRA Section

2.4-1 for containment buildings and in Section 2.4-3 for turbine building(s) and fuel storage building(s). The applicant confirmed that fasteners and rail hardware are in scope and subject to an AMR. They are, however, considered bulk commodities and are included in LRA Table 2.4-4, line item “structural bolting.” Since the language of the line item as currently written could be misleading, in a follow-up RAI, dated May 12, 2008, the staff requested the applicant to correct the line item “crane rails and girders” in LRA Table 2.4-3 to read “cranes, rails and girders."

In its response to the follow-up RAI, dated June 11, 2008, the applicant stated that the line item "crane rails and girders" LRA Table 2.4-3 and LRA Table 3.5.2-3 is corrected to read "cranes, rails and girders". Since the applicant corrected the line item, the staff finds the response acceptable.

In RAI 2.4.3-5, dated January 28, 2008, the staff requested that the applicant confirm whether the component identified as "Structural Steel: beams, columns, plates" in LRA Table 2.4-3 includes bracings, welds, and bolted connections or indicate where they were included. The staff also requested that the applicant include "Battery Racks" (e.g., for emergency diesels), turbine generator pedestals and their structural bearing pads, and diesel generator pedestals and the concrete curb around diesel generator foundations as components subject to an AMR.

In its response, dated February 27, 2008, the applicant clarified that the component identified as “Structural Steel: beams, columns, plates, trusses” in LRA Table 2.4-3 includes bracings and welds associated with the component. The applicant added that bolted connections are addressed in LRA Section 2.4.4 and LRA Table 2.4-4. The applicant further clarified that battery racks (e.g., for emergency diesel) are within the scope of license renewal and subject to an AMR and are included as bulk commodities within line item “component and piping support” in LRA Table 2.4-4. The applicant further clarified that the turbine generator pedestals, diesel generator pedestals, and the concrete curb around diesel generator foundations are included within the LRA Table 2.4-3 as part of line item “Floor slabs, interior walls and ceiling” and line item “Foundations.” The applicant stated that structural bearing pads associated with the turbine generator pedestal are not within the scope of license renewal because they are not safety-related and not required to demonstrate compliance with 10 CFR 54.4(a)(3). Failure of the bearing pads will not prevent satisfactory accomplishment of a safety function. Based on this response, the staff finds that the applicant has adequately clarified the inclusion or justified the exclusion, as applicable, of each of the structural components noted in the RAI. The staff finds the applicant’s response adequately addresses the staff’s concerns raised in the RAI and, therefore, is acceptable. The staff’s concern described in RAI 2.4.3-5 is resolved.

2.4.3.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI and follow-up RAI responses to determine whether the applicant failed to identify any SCs within the scope of license renewal. The staff found no omissions. In addition, the staff sought to determine if the applicant failed to identify any SCs subject to an AMR. Again, the staff found no omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the turbine buildings, auxiliary buildings, and other structures SCs within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4.4 Bulk Commodities

2.4.4.1 Summary of Technical Information in the Application

LRA Section 2.4.4 describes bulk commodities, the structural components or commodities that perform or support intended functions of in-scope SSCs. Bulk commodities unique to a specific structure are included in the review for that structure (LRA Sections 2.4.1 through 2.4.3). Bulk commodities common to Indian Point in-scope SSCs (*e.g.*, anchors (including rock bolts), embedments, pipe and equipment supports, instrument panels and racks, cable trays, and conduits) are addressed in this section.

Insulation may have the specific intended functions of (1) controlling the heat load during DBAs in areas with safety-related equipment, (insulation and Insulation jacket) or (2) maintaining integrity such that falling insulation does not damage safety-related equipment (reflective metallic-type reactor vessel insulation).

Bulk commodities have the following intended functions for 10 CFR 54.4(a)(1), (a)(2), and (a)(3): Provide support, shelter, and protection for safety-related equipment and nonsafety-related equipment within the scope of license renewal.

LRA Table 2.4-4 identifies bulk commodities' component types, grouped by material (steel/other metals, concrete, other materials), within the scope of license renewal and subject to an AMR as well as their intended functions.

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.

During its review, the staff evaluated the structural component functions described in the LRA and UFSAR to verify that the applicant had not omitted from the scope of license renewal any SCs with intended functions, as required by 10 CFR 54.4(a). The staff then reviewed those SCs that the applicant identified as within the scope of license renewal to verify that the applicant had 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 2.4.4, the staff identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

In LRA Section 2.4.4 and LRA Table 2.4-4, the applicant discussed and listed the structural bulk commodities components common to in-scope structures that are subject to an AMR. Because of a lack of clarity in LRA Table 2.4-4, in RAI 2.4.4-1, dated January 28, 2008, the staff requested that the applicant confirm or clarify and appropriately address whether the following bulk commodities have been screened in as components subject to an AMR, in LRA Table 2.4-4:

(i) expansion anchors
(ii) vibration isolation elements
(iii) flood curbs

(iv) waterproofing membrane
(v) sliding support bearings and sliding support surfaces

The applicant also was requested to explicitly state the specific materials that are classified as "Other Materials" in LRA Table 2.4-4.

In its response, dated February 27, 2008, the applicant clarified the screening of each component identified in the RAI as follows:

(i) Expansion Anchors are addressed in LRA Table 2.4-4 under line item "anchorages/embedments."

(ii) There are no vibration isolation elements identified as within the scope of license renewal and subject to AMR.

(iii) Flood curbs are included in the review of structures. Considered integral to floor slabs, they are included in the review for those line items identified in LRA Tables 2.4-1 as "beams, columns, interior walls, slabs," Table 2.4-2 as "beams, columns, floor slabs and walls" and Table 2.4-3 as "floor slabs, interior walls, ceilings."

(iv) Waterproofing membranes are not in-scope. Waterproofing membranes are not safety-related and are not required to demonstrate compliance with 10 CFR 54.4(a)(3). Failure of these membranes will not prevent satisfactory accomplishment of a safety function.

(v) The sliding support bearings and sliding support surfaces identified as within the scope of license renewal are documented in LRA Table 2.4-1, line item "Lubrite sliding surfaces."

The applicant also stated that materials classified as "Other Materials" in LRA Table 2.4-4 are those materials that were not captured by what is considered basic structural materials (i.e., steel or concrete) and that the material make-up of these commodities is specifically identified in LRA Section 3.5.2.1.4.

The staff finds that the applicant adequately clarified the issues related to the screening of the five specific structural components identified in the RAI. The staff also verified that, in LRA Section 3.5.2.1.4, the applicant identified the bulk commodity component materials that make up the line item "Other Materials." These other materials, identified in LRA Section 3.5.2.1.4 are aluminum, cera blanket, cerafiber, elastomer, fiberglass and/or calcium silicate, mineral wool, and pyrocrete. The staff finds that the applicant's response adequately addresses the staff's concerns raised in the RAI and, therefore, is acceptable. The staff's concern described in RAI 2.4.4-1 is resolved.

In RAI 2.4.4-2, dated January 28, 2008, with regard to the components "insulation" and "insulation jacket" identified in LRA Table 2.4-4, the staff pointed out that it was unclear as to which insulation (and material) and insulation jacket within the scope of license renewal were included in these items. The applicant was requested to clarify whether the insulation and jacketing on the containment liner, reactor vessel, RCS, MS and FW systems are included.

The applicant also was requested to provide the following information with regard to insulation that is used to control the maximum temperature of safety-related structural elements:

(a) Identify the structures and structural components designated as within the scope of license renewal that have insulation and/or insulation jacketing, and identify their location in the plant. Identify locations of the thermal insulation that serve an intended function in accordance with 10 CFR 54.4(a)(2) and describe the scoping and screening results of thermal insulation, and provide the technical basis for its exclusion from the scope of license renewal.

(b) For insulation and insulation jacketing materials associated with item (a) above that do not require aging management, submit the technical basis for this conclusion, including plant-specific operating experience.

(c) For insulation and insulation jacketing materials associated with item (a) above that require aging management, indicate the applicable LRA sections that identify the AMP(s) credited to manage their aging.

In its response, dated February 27, 2008, the applicant addressed each of the items in the RAI as follows:

(a) The applicant stated that structures and structural components within the scope of license renewal that have insulation and/or insulation jacketing that serves an intended function pursuant to 10 CFR 54.4(a)(2) are the containment liner and high-temperature piping at containment piping penetrations. The applicant stated that the containment liner insulation is listed in LRA Table 2.4-1, and the insulation associated with hot containment penetrations is addressed in LRA Section 2.4.4 and in LRA Table 2.4-4.

(b) The applicant clarified that insulation and insulation jacketing materials associated with item (a) do not require an AMP because these insulation materials are exposed to indoor air environment and the containment liner insulation is encapsulated in a stainless steel jacket and is not subject to external environments. The applicant further stated that, in these environments, these materials have no aging effects requiring management. The operating experience review specifically considered plant-specific information related to the effects of aging on insulation materials, and that review confirmed that no aging effects requiring management are applicable to the insulation materials that are subject to an AMR at IP2 and IP3.

(c) The applicant stated that aging management review results for insulation and insulation jacketing materials are shown in LRA Tables 3.5.2-1 and 3.5.2-4.

The applicant reiterated that, since there are no aging effects requiring management for insulation, no AMP is credited, noting that insulation materials in an indoor air environment are not susceptible to degradation from the effects of aging.

In its response, and in the context of insulation that serves to limit the temperature of safety-related structural components, the applicant confirmed that the structures and structural components, within the scope of license renewal and subject to an AMR, that have insulation and/or insulation jacketing are the containment liner and high-temperature piping at the containment penetrations. The applicant concluded that none of the in-scope insulating material used at IP2 and IP3 requires any management for aging effects because of its favorable operating experience and the fact that it is only exposed to an indoor air environment and encapsulated in metallic jacketing. The staff finds that this conclusion is consistent with the GALL Report, Volume II. The staff further finds that the applicant's response to RAI 2.4.4-2 adequately addressed the staff's question with regard to insulation and, therefore, is acceptable. The staff's concern described in RAI 2.4.4-2 is resolved.

2.4.4.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI responses to determine whether the applicant failed to identify any SCs within the scope of license renewal. The staff found no omissions. In addition, the staff sought to determine whether the applicant failed to identify any SCs subject to an AMR. The staff found no omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the bulk commodities SCs within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

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

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

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

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

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

After its review of the scoping results, the staff evaluated the applicant's screening results. For those SCs with intended functions, the staff sought to determine whether (1) the functions are performed with moving parts or a change in configuration or properties, or (2) the SCs are subject to replacement after a qualified life or specified time period, as described in

10 CFR 54.21(a)(1). For those meeting neither of these criteria, the staff sought to confirm that these SCs were subject to an AMR, as required by 10 CFR 54.21(a)(1). The staff requested additional information to resolve any omissions or discrepancies identified.

2.5.1 Electrical and Instrumentation and Control Systems

2.5.1.1 Summary of Technical Information in the Application

LRA Section 2.5 describes the electrical and instrumentation and control systems. As stated in LRA Section 2.1.1, plant electrical and instrument and control (I&C) systems are included in the scope of license renewal as are electrical and I&C components in mechanical systems. The default inclusion of plant electrical and I&C systems in the scope of license renewal reflects the method for the integrated plant assessment (IPA) of electrical systems. This method is different from the methods used for mechanical systems and structures.

The applicant stated that the basic philosophy of the electrical and I&C components IPA is that components are included in the review unless specifically screened out. In the plant spaces approach, this method eliminates the need for unique identification of every component and its specific location so components are not excluded improperly from an AMR. 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 safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for SBO (10 CFR 50.63).

The applicant further stated that the offsite power system provides the electrical interconnection between IPEC and the offsite transmission network. The offsite power sources required to support SBO recovery actions supply the station auxiliary transformers. Specifically, the offsite power recovery path includes the station auxiliary transformers, the 138 kV and 13.8 kV switchyard circuit breakers supplying the station auxiliary transformers, the circuit breaker-to-transformer and transformer-to-onsite electrical distribution interconnections, control circuits, and structures.

The electrical and instrumentation and control systems perform functions that support SBO and EQ.

LRA Table 2.5-1 identifies electrical and instrumentation and control systems component types within the scope of license renewal and subject to an AMR:

- cable connections (metallic parts)
- electrical cables and connections not subject to 10 CFR 50.49 EQ requirements
- electrical cables not subject to 10 CFR 50.49 EQ requirements used in instrumentation circuits
- electrical connections not subject to 10 CFR 50.49 EQ requirements exposed to borated

water leakage

- fuse holders (insulation material)
- high-voltage insulators for SBO recovery
- inaccessible medium-voltage (2kV to 35kV) cables not subject to 10 CFR 50.49 EQ requirements
- metal-enclosed bus (non-segregated) and connections for SBO recovery
- metal-enclosed bus (non-segregated), insulation/insulators for SBO recovery
- metal-enclosed bus (non-segregated) enclosure assemblies for SBO recovery
- switchyard bus and connections for SBO recovery
- transmission conductors and connections for SBO recovery
- 138 kV direct burial insulated transmission cables

The intended functions of the electrical and instrumentation and control systems component types within the scope of license renewal include the following functions:

- connect specified electrical circuit portions to deliver voltage, current, or signals
- insulate and support electrical conductors
- structurally or functionally support equipment required for the 10 CFR 54.4(a)(3) regulated events

2.5.1.2 Staff Evaluation

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

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

During its review of LRA Section 2.5, the staff identified several areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff’s RAIs as discussed below.

The staff noted that, according to LRA Section 2.5, two independent paths from the safety-related buses to the first circuit breaker from the offsite transmission line were not included within the scope of license renewal. General Design Criterion 17 of 10 CFR Part 50, Appendix A, requires that electric power from the transmission network to the onsite electric distribution system be supplied by two physically independent circuits to minimize the likelihood of their simultaneous failure. In addition, the staff noted that the guidance provided by letter dated April 1, 2002, "Staff Guidance on Scoping of Equipment Relied on to Meet the Requirements of the Station Blackout Rule (10 CFR 50.63) for License Renewal (10 CFR 54.4(a)(3))," and later incorporated in SRP-LR Section 2.5.2.1.1, states:

> For purposes of the license renewal rule, the staff has determined that the plant system portion of the offsite power system that is used to connect the plant to the offsite power source should be included within the scope of the rule. This path typically includes switchyard circuit breakers that connect to the offsite system power transformers (startup transformers), the transformers themselves, the intervening overhead or underground circuits between circuit breaker and transformer and transformer and onsite electrical system, and the associated control circuits and structures. Ensuring that the appropriate offsite power system long-lived passive SCs 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.

According to this guidance, the NRC staff position is that, for the purposes of license renewal, the specified offsite power recovery path elements should be included in the scope of license renewal. In RAI 2.5-1, dated October 24, 2007, the staff conveyed its position that both paths from the safety-related 480 V buses to the first circuit breaker from the offsite line used to control the offsite circuits to the plant should be included within the scope of license renewal. Therefore, the staff requested that the applicant provide a detailed explanation of which high voltage breakers and other components in the switchyard will be connected from the startup transformers up to the offsite power system for the purpose of SBO recovery.

In its response, dated November 16, 2007, the applicant stated that the Buchanan substation, which includes the 345 kV, 138 kV, and 13.8 kV sections, provides for the interconnection of multiple sources of power and constitutes the offsite power source for IP2 and IP3.

In the LRA, Figure 2.5-2, “IP2 Offsite Power Scoping Diagram,” shows the IP2 primary offsite power source, the 6.9 kV source from the station auxiliary transformer which is connected to the 138 kV Buchanan substation through circuit breaker F2. The applicant’s November 16, 2007 response revised the scoping boundary for both offsite power sources for IP2. First, the station auxiliary transformer is connected to the 138 kV Buchanan substation via switchyard bus, overhead transmission conductors, and underground transmission conductors through motor-operated disconnect F3A (primary path). The staff determined that this change to a motor-operated disconnect is not consistent with the staff guidance and, therefore, is unacceptable. Secondly, the November 16, 2007 response delineated the secondary offsite power source (alternate path). The gas turbine (GT) autotransformer is connected to the 13.8 kV Buchanan substation via underground medium voltage cable through 13.8 kV circuit breaker F2-3.

LRA Figure 2.5-3, “IP3 Offsite Power Scoping Diagram,” was modified in the applicant’s November 16, 2007, response to add the secondary offsite power feeder, indicating that the 6.9 kV buses receive power from two independent sources: the 138 kV/6.9 kV station auxiliary transformer and the 13.8 kV/6.9 kV GT autotransformer. The station auxiliary transformer is connected to the 138 kV Buchanan substation via switchyard bus and overhead transmission conductors through circuit breaker BT2-6, and the GT autotransformer is connected to the 13.8 kV Buchanan substation via underground medium voltage cable through 13.8 kV circuit breaker F3-1.

During a telephone conference, documented in a conference call summary dated December 4, 2007, the staff requested that Entergy explain its response to RAI 2.5-1 with regard to why the connection point for offsite power (for the purpose of station blackout recovery) changed from circuit breaker F2 to a motor-operated disconnect for IP2. The staff informed the applicant that this change is not consistent with the staff's guidance and, therefore, is unacceptable.

In a letter dated March 24, 2008, the applicant modified its scoping boundary for the primary offsite power path for IP2, as shown in modified Figure 2.5-2, "IP2 Offsite Power Scoping Diagram." The station auxiliary transformer is connected to the 138 kV Buchanan substation via switchyard bus, overhead transmission conductors, and underground transmission conductors through switchyard breakers F2 and BT 3-4. The change from motor-operated disconnects to 138 kV circuit breakers addresses the staff's concern for the scoping boundary for the primary offsite power path and provides closure for Open Item 2.5-1.

By letter dated May 20, 2009, the staff requested that the applicant explain why the secondary offsite circuit (the delayed access circuit) path, from the first inter-tie with the offsite distribution systems at the Buchanan substations to the safety buses, was not included in the scope of license renewal.

By letter dated June 12, 2009, the applicant stated that the components up to and including either the 138 kV circuit breaker F1 or 345 kV circuit breaker F7 for IP2, and either the 138 kV circuit breaker F3 or 345 kV circuit breaker F7 for IP3 were not included in the scope of license renewal because they do not meet the scoping criteria specified in 10 CFR 54.4. The staff finds the response acceptable as it is in accordance with the IP2 and IP3 current licensing basis and applicable regulatory requirements. This closes Open Item 2.5-1.

The applicant did not specifically exclude the associated control circuits and structures for the circuit breakers and thus, it was unclear if these components are included in the scope of license renewal. In RAI 2.5-5, the staff requested that the applicant confirm whether the associated control cables and structures for the circuit breakers have been included in the scope of license renewal. In letter dated August 14, 2008, the applicant clarified its response to RAI 2.5-1 and confirmed that the associated control cables and structures for the circuit breakers have been included in the scope of license renewal. Therefore, the staff finds the response acceptable.

In RAI 2.5-2, dated October 24, 2007, the staff requested the applicant to clarify why elements such as resistance temperature detectors (RTDs), sensors, thermocouples, and transducers are not included in the list of components and/or commodity groups subject to an AMR if a pressure boundary is applicable. In its response, dated November 16, 2007, the applicant stated that RTDs, sensors, thermocouples, and transducers associated with the pressure boundary are evaluated in mechanical systems. Examples are thermowells and flow elements. LRA Section 2.1.2.3.1 states that the pressure boundary function that may be associated with some electrical and I&C components was considered in the mechanical aging management reviews. The staff verified through a sampling of mechanical systems that the applicant had scoped and screened the passive mechanical components (e.g., thermowells and flow elements) associated with the electrical elements in question. Therefore, the staff finds the response acceptable.

In RAI 2.5-3, dated October 24, 2007, the staff requested clarification as to why Section 2.5 of the LRA did not include splices, terminal blocks, control cables, and isolated-phase bus in the commodity group of "cables & connections, bus, electrical portions of electrical and I&C penetration assemblies." In its response, dated November 16, 2007, the applicant stated that electrical splices, terminal blocks, and control cables were included in the commodity group "electrical cables and connections not subject to 10 CFR 50.49 EQ requirements." Thus, these components are subject to an aging management review. The isolated-phase bus is not subject to an AMR because it does not perform an intended function. Since the applicant clarified that the electrical splices, terminal blocks, and control cables are subject to an AMR, the staff finds the response acceptable.

2.5.1.3 Conclusion

The staff reviewed the LRA, UFSAR, and RAI responses to determine whether the applicant failed to identify any SSCs within the scope of license renewal. In addition, the staff sought to determine whether the applicant failed to identify any components subject to an AMR. The staff found no such omissions. On the basis of its review, the staff concludes that the applicant has adequately identified the electrical and I&C component commodity groups 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" and determines that the applicant's scoping and screening methodology is consistent with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), except as noted above. Accordingly, the staff concludes that the applicant has adequately identified those systems and 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).

With regard to these matters, the staff concludes that reasonable assurance exists that the activities authorized by the renewed licenses will continue to be conducted in accordance with the CLB and that any changes made to the CLB, in order to comply with 10 CFR 54.29(a), are in accordance with the Atomic Energy Act of 1954, as amended, and NRC regulations.

SECTION 3

AGING MANAGEMENT REVIEW RESULTS

This section of the safety evaluation report (SER) evaluates aging management programs (AMPs) and aging management reviews (AMRs) for Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3), by the staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff). In license renewal application (LRA), Appendix B, Entergy Nuclear Operations, Inc. (Entergy or the applicant) described the 41 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 referenced NUREG-1801, Revision 1, "Generic Aging Lessons Learned (GALL) Report" (the GALL Report), dated September 2005. The GALL Report contains the staff's generic evaluation of the existing plant programs and documents the technical basis for determining where existing programs are adequate without modification, and where existing programs should be augmented for the period of extended operation. The evaluation results documented in the GALL Report indicate that many of the existing programs are adequate to manage the aging effects for particular license renewal structures and components (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 is split into two volumes. Volume 1 summarizes the aging management reviews that are discussed in Volume 2. Volume 2 lists generic aging management reviews (AMRs) of SSC that may be in the scope of License Renewal Applications (LRAs) and identifies GALL AMPs that are acceptable to manage the listed aging effects. Revision 1 of the GALL Report incorporates changes based on experience gained from numerous NRC staff reviews of LRAs and other insights identified by stakeholders.

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

NUREG-1800, Revision 1, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants” (SRP-LR), dated September 2005, was prepared based on both the GALL Report model and lessons learned from the demonstration project.

If an LRA references the GALL Report as the approach used to manage aging effects, the NRC staff will use the GALL Report as a basis for the LRA assessment consistent with guidance specified in the SRP-LR.

The staff‘s review was in accordance with Title 10, Part 54, of the *Code of Federal Regulations* (10 CFR Part 54), “Requirements for Renewal of Operating Licenses for Nuclear Power Plants,” and the guidance of the SRP-LR and the GALL Report.

In addition to its review of the LRA, the staff conducted an onsite audit of selected AMPs and AMRs, during the weeks of August 26, 2007 and October 22, 2007, November 27 - 29, 2007, and February 19 – 22, 2008. 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, the need for formal correspondence between the staff and the applicant is reduced, and the result is an improvement in review efficiency.

3.0.1 Format of the License Renewal Application

The applicant submitted an application that follows the standard LRA format. This standard format was agreed to by the staff and the Nuclear Energy Institute (NEI) in a letter dated April 7, 2003. The revised LRA format incorporates lessons learned from the staff’s reviews of the previous five LRAs, which used a format developed from information gained during a staff-NEI demonstration project conducted to evaluate the use of the GALL Report in the LRA review process.

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

(1) Table 1’s: 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 2’s: 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 Entergy application is essentially the same. The intent of the revised format of the Entergy LRA was to modify the tables in LRA Section 3 to provide additional information that would assist in the staff’s review. In its Table 1’s, the applicant summarized the portions of the application that it considered to be consistent with the GALL Report. In its Table 2’s, 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 1's

Each Table 1 compares in summary, how the facility aligns with the corresponding tables in the GALL Report. The tables are essentially the same as Tables 1 through 6 in the GALL Report, except that the "Type" column has been replaced by an "Item Number" column and the "Item Number in GALL" column has been replaced by a "Discussion" column. The "Item Number" column is a means for the staff reviewer to cross-reference Table 2's with Table 1's. In the "Discussion" column the applicant provided clarifying information. The following are examples of information that might be contained within this column:

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

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

3.0.1.2 Overview of Table 2's

Each Table 2 provides the detailed results of the AMRs for components identified in LRA Section 2 as subject to an AMR. The LRA has a Table 2 for each of the systems or structures within a specific system grouping (e.g., reactor coolant system (RCS), engineered safety features (ESF), auxiliary systems, etc.). For example, the ESF group has tables specific to the containment spray (CS) system, containment isolation (CI) system, and emergency core cooling system (ECCS). Each Table 2 consists of nine columns:

- Component Type – The first column lists LRA Section 2 component types subject to an AMR in alphabetical order.
- Intended Function – The second column identifies the license renewal intended functions, including abbreviations, where applicable, for the listed component types. Definitions and abbreviations of intended functions are in LRA Table 2.0-1.
- Material – The third column lists the particular construction material(s) for the component type.
- Environment – The fourth column lists the environments to which the component types are exposed. Internal and external service environments are indicated with a list of these environments in LRA Tables 3.0-1, 3.0-2, and 3.0-3.
- Aging Effect Requiring Management – The fifth column lists aging effects requiring management (AERMs). As part of the AMR process, the applicant determined any AERMs for each combination of material and environment.
- Aging Management Programs – The sixth column lists the AMPs that the applicant uses to manage the identified aging effects.

- NUREG-1801 Vol. 2 Item – The seventh column lists the GALL Report item(s) identified in the LRA as similar to the AMR results. The applicant compared each combination of component type, material, environment, AERM, and AMP in LRA Table 2 with the GALL Report items. If there are no corresponding items in the GALL Report, the applicant leaves the column blank in order to identify the AMR results in the LRA tables corresponding to the items in the GALL Report tables.
- Table 1 Item – The eighth column lists the corresponding summary item number from LRA Table 1. If the applicant identifies in each LRA Table 2 AMR results consistent with the GALL Report, the Table 1 line item summary number should be listed in LRA Table 2. If there is no corresponding item in the GALL Report, column eight is left blank. In this manner, the information from the two tables can be correlated.
- Notes – The ninth column lists the corresponding notes used to identify how the information in each Table 2 aligns with the information in the GALL Report. The notes, identified by letters, were developed by an NEI work group and will be used in future LRAs. Any plant-specific notes identified by numbers provide additional information about the consistency of the line item with the GALL Report.

3.0.2 Staff's Review Process

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

(1) For items that the applicant stated as 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 as 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 AMP elements. However, any deviation from or exception to the GALL AMP should be described and justified.

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

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

Staff audits and technical reviews of the applicant's AMPs and AMRs determine whether the effects of aging on SCs will be adequately managed so that the intended function will be maintained consistent with the plant's current licensing basis (CLB) for the period of extended operation, as required by 10 CFR Part 54.21.

3.0.2.1 Review of Programs

For programs for which the applicant claimed consistency with the GALL AMPs, the staff conducted either an audit or a technical review to verify the claim. For each program with one or more deviations, the staff evaluated each deviation to determine whether the deviation was acceptable and whether the modified program would adequately manage the aging effect(s) for which it was credited. For programs not evaluated in the GALL Report, the staff performed a full review to determine their adequacy. The staff evaluated the programs against the following 10 program elements defined in SRP-LR Appendix A.

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

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

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

(4) Detection of Aging Effects – 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/one-time inspections to ensure timely detection of aging effects.

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

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

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

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

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

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

Details of the staff's audit evaluation of program elements (1) through (6) are documented in SER Section 3.0.3.

The staff reviewed the applicant's quality assurance (QA) program and documented its evaluations in SER Section 3.0.4. The staff's evaluation of the QA program included assessment of program elements (7) "corrective actions," (8) "confirmation process," and (9) "administrative controls.

The staff reviewed the information on program element (10) "operating experience," and documented its evaluation in SER Section 3.0.3.

3.0.2.2 Review of AMR Results

Each LRA Table 2 contains information concerning whether or not the AMRs identified by the applicant align with the GALL Report AMRs. For a given AMR in a Table 2, the staff reviewed the intended function, material, environment, AERM, and AMP combination for a particular system component type. Item numbers in column seven of the LRA, “NUREG-1801 Vol. 2 Item,” correlate to an AMR combination as identified in the GALL Report. The staff also conducted onsite audits to verify these correlations. A 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.

3.0.2.3 UFSAR Supplement

Consistent with the SRP-LR for the AMRs and AMPs that it reviewed, the staff also reviewed the UFSAR supplement, which summarizes the applicant’s programs and activities for managing aging effects for the period of extended operation, as required by 10 CFR 54.21(d).

3.0.2.4 Documentation and Documents Reviewed

In its review, the staff used the LRA, LRA supplements, the SRP-LR, and the GALL Report.

During the onsite audits, the staff also examined the applicant’s justifications to verify that the applicant’s activities and programs will adequately manage the effects of aging on SCs. The staff also conducted detailed discussions and interviews with the applicant’s license renewal project personnel and others with technical expertise relevant to aging management. The staff's audit activities are documented in the Audit Report (ADAMS Accession No. ML083540662).

3.0.3 Aging Management Programs

SER Table 3.0.3-1 presents the AMPs credited by the applicant and described in LRA Appendix B. The table also indicates the systems or structures that credit the AMPs and the GALL AMP with which the applicant claimed consistency and shows the section of this SER in which the staff’s evaluation of the program is documented.

Table 3.0.3-1 IP2 and IP3 Aging Management Programs

AMP (LRA Section)	New or Existing AMP	GALL Report Comparison	GALL Report AMPs	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Aboveground Steel Tanks Program (B.1.1)	Existing	Consistent with enhancements	XI.M29	auxiliary systems / steam and power conversion systems	3.0.3.2.1
Bolting Integrity Program (B.1.2)	Existing	Consistent with enhancement	XI.M18	reactor vessel, internals and reactor coolant system / engineered safety features systems / auxiliary systems / steam and power conversion systems	3.0.3.2.2
Boraflex Monitoring Program (B.1.3)	Existing	Consistent with exceptions	XI.M22	auxiliary systems	3.0.3.2.3
Boral Surveillance Program (B.1.4)	Existing	Plant-specific		auxiliary systems	3.0.3.3.1
Boric Acid Corrosion Prevention Program (B.1.5)	Existing	Consistent	XI.M10	reactor vessel, internals and reactor coolant system / engineered safety features systems / auxiliary systems / structures and component supports / electrical and instrumentation and controls	3.0.3.1.1
Buried Piping and Tanks Inspection Program (B.1.6)	New	Consistent	XI.M34	engineered safety features systems / auxiliary systems / steam and power conversion systems	3.0.3.1.2
Containment Leak Rate Program (B.1.7)	Existing	Consistent	XI.S4	structures and component supports	3.0.3.1.3
Containment Inservice Inspection Program (B.1.8)	Existing	Plant-specific		structures and component supports	3.0.3.3.2
Diesel Fuel Monitoring Program (B.1.9)	Existing	Consistent with exceptions and enhancements	XI.M30	auxiliary systems	3.0.3.2.4
Environmental Qualification of Electric Components Program (B.1.10)	Existing	Consistent	X.E1	electrical and instrumentation and controls	3.0.3.1.4

AMP (LRA Section)	New or Existing AMP	GALL Report Comparison	GALL Report AMPs	LRA Systems or Structures That Credit the AMP	Staff's SER Section
External Surfaces Monitoring Program (B.1.11)	Existing	Consistent with enhancement	XI.M36	reactor vessel, internals and reactor coolant system / engineered safety features systems / auxiliary systems / steam and power conversion systems	3.0.3.2.5
Fatigue Monitoring Program (B.1.12)	Existing	Consistent with exception and enhancement	X.M1	reactor vessel, internals and reactor coolant system / engineered safety features systems / auxiliary systems / steam and power conversion systems	3.0.3.2.6
Fire Protection Program (B.1.13)	Existing	Consistent with exception and enhancements	XI.M26	auxiliary systems / structures and component supports	3.0.3.2.7
Fire Water System Program (B.1.14)	Existing	Consistent with exception and enhancements	XI.M27	auxiliary systems / structures and component supports	3.0.3.2.8
Flow-Accelerated Corrosion Program (B.1.15)	Existing	Consistent with exception	XI.M17	auxiliary systems / steam and power conversion systems	3.0.3.1.5
Flux Thimble Tube Inspection Program (B.1.16)	Existing	Consistent with enhancements	XI.M37	reactor vessel, internals and reactor coolant system	3.0.3.2.9
Heat Exchanger Monitoring Program (B.1.17)	Existing	Plant-specific		engineered safety features systems / auxiliary systems	3.0.3.3.3
Inservice Inspection Program (B.1.18)	Existing	Plant-specific		reactor vessel, internals and reactor coolant system / structures and component supports	3.0.3.3.4
Masonry Wall Program (B.1.19)	Existing	Consistent with enhancement	XI.S5	structures and component supports	3.0.3.2.10
Metal-Enclosed Bus Inspection Program (B.1.20)	Existing	Consistent with exceptions and enhancements	XI.E4	electrical and instrumentation and controls	3.0.3.2.11
Nickel Alloy Inspection Program (B.1.21)	Existing	Plant-specific		reactor vessel, internals and reactor coolant system	3.0.3.3.5
Non-EQ Bolted Cable Connections Program (B.1.22)	New	Plant-specific		electrical and instrumentation and controls	3.0.3.3.6

AMP (LRA Section)	New or Existing AMP	GALL Report Comparison	GALL Report AMPs	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Non-EQ Inaccessible Medium-Voltage Cable Program (B.1.23)	New	Consistent	XI.E3	electrical and instrumentation and controls	3.0.3.1.6
Non-EQ Instrumentation Circuits Test Review Program (B.1.24)	New	Consistent	XI.E2	electrical and instrumentation and controls	3.0.3.1.7
Non-EQ Insulated Cables and Connections Program (B.1.25)	New	Consistent	XI.E1	electrical and instrumentation and controls	3.0.3.1.8
Oil Analysis Program (B.1.26)	Existing	Consistent with exception and enhancements	XI.M39	engineered safety features systems / auxiliary systems / steam and power conversion systems	3.0.3.2.12
One-Time Inspection Program (B.1.27)	New	Consistent	XI.M32	engineered safety features systems / auxiliary systems / steam and power conversion systems	3.0.3.1.9
One-Time Inspection - Small Bore Piping Program (B.1.28)	New	Consistent	XI.M35	reactor vessel, internals and reactor coolant system	3.0.3.1.10
Periodic Surveillance and Preventive Maintenance Program (B.1.29)	Existing	Plant-specific		engineered safety features systems / auxiliary systems / steam and power conversion systems / structures and component supports	3.0.3.3.7
Reactor Head Closure Studs Program (B.1.30)	Existing	Consistent	XI.M3	reactor vessel, internals and reactor coolant system	3.0.3.1.11
Reactor Vessel Head Penetration Inspection Program (B.1.31)	Existing	Consistent	XI.M11A	reactor vessel, internals and reactor coolant system	3.0.3.1.12
Reactor Vessel Surveillance Program (B.1.32)	Existing	Consistent with enhancement	XI.M31	reactor vessel, internals and reactor coolant system	3.0.3.2.13
Selective Leaching Program (B.1.33)	New	Consistent	XI.M33	engineered safety features systems / auxiliary systems	3.0.3.1.13
Service Water Integrity Program (B.1.34)	Existing	Consistent	XI.M20	auxiliary systems	3.0.3.1.14

AMP (LRA Section)	New or Existing AMP	GALL Report Comparison	GALL Report AMPs	LRA Systems or Structures That Credit the AMP	Staff's SER Section
Steam Generator Integrity Program (B.1.35)	Existing	Consistent with enhancement	XI.M19	reactor vessel, internals and reactor coolant system	3.0.3.2.14
Structures Monitoring Program (B.1.36)	Existing	Consistent with enhancements	XI.S6 and XI.M23	structures and component supports	3.0.3.2.15
Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (B.1.37)	New	Consistent	XI.M12	reactor vessel, internals and reactor coolant system	3.0.3.1.15
Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program (B.1.38)	New	Consistent	XI.M13	reactor vessel, internals and reactor coolant system	3.0.3.1.16
Water Chemistry Control - Auxiliary Systems Program (B.1.39)	Existing	Plant-specific		engineered safety features systems / auxiliary systems	3.0.3.3.8
Water Chemistry Control - Closed Cooling Water Program (B.1.40)	Existing	Consistent with exceptions and enhancements	XI.M21	reactor vessel, internals and reactor coolant system / engineered safety features systems / auxiliary systems	3.0.3.2.16
Water Chemistry Control - Primary and Secondary Program (B.1.41)	Existing	Consistent with enhancement	XI.M2	reactor vessel, internals and reactor coolant system / engineered safety features systems / auxiliary systems / steam and power conversion systems / structures and component supports	3.0.3.2.17

3.0.3.1 Programs Consistent with the GALL Report

In LRA Appendix B, the applicant described the following programs as consistent with the GALL Report:

- Boric Acid Corrosion Prevention Program
- Buried Piping and Tanks Inspection Program
- Containment Leak Rate Program
- Environmental Qualification of Electric Components Program
- Flow-Accelerated Corrosion Program
- Non-EQ Inaccessible Medium-Voltage Cable Program
- Non-EQ Instrumentation Circuits Test Review Program

- Non-EQ Insulated Cables and Connections Program
- One-Time Inspection Program
- One-Time Inspection - Small Bore Piping Program
- Reactor Head Closure Studs Program
- Reactor Vessel Head Penetration Inspection Program
- Selective Leaching Program
- Service Water Integrity Program
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program
- Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program

3.0.3.1.1 Boric Acid Corrosion Prevention Program

Summary of Technical Information in the Application. LRA Section B.1.5 describes the existing Boric Acid Corrosion Prevention Program as consistent with GALL AMP XI.M10, "Boric Acid Corrosion."

The Boric Acid Corrosion Prevention Program implements Generic Letter (GL) 88-05 recommendations to monitor the condition of components on which borated reactor water may leak. The program detects boric acid leakage by periodic visual inspection of (a) systems containing borated water for deposits of boric acid crystals and the presence of moisture and (b) adjacent structures, components, and supports, for evidence of leakage. This program, which manages loss of material and loss of circuit continuity, evaluates leakage discovered by other activities. The applicant has made program improvements as suggested in NRC Regulatory Issue Summary (RIS) 2003-013.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Boric Acid Corrosion Prevention Program and basis documents to verify consistency with GALL AMP XI.M10. Details of the staff's audit of the applicant's AMP are documented in the Audit Report (ADAMS Accession No. ML083540662). As documented in the report, the staff found that elements (1) through (6) are consistent with the corresponding elements in GALL AMP XI.M10. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

Operating Experience. LRA Section B.1.5 states that inspections of the IP2 containment building in April 2005, November 2005, and May 2006 detected minor boron leakage. Also, a March 2005 inspection detected boron leakage at IP3 reactor coolant boundary components that may be subject to boric acid leakage and corrosion. The applicant stated that early detection prevented boric acid wastage of affected components and adjacent structures and components. It further stated that detection of degradation followed by corrective action prior to loss of intended function has proven that the program effectively manages aging effects for passive components.

LRA Section B.1.5 also states that the Boric Acid Corrosion Prevention Program was enhanced to include recommendations of the Westinghouse Owner's Group Westinghouse Commercial Atomic Power (WCAP)-15988-NP, "Generic Guidance to Best Practice 88-05 Boric Acid Inspection Program," Electric Power Research Institute (EPRI) Technical Report 1000975, "Boric Acid Corrosion Guidebook," and NRC Bulletin 2003-02 "Leakage from Reactor Coolant Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity."

Ongoing program improvements, through incorporation of lessons learned from industry operating experience, assure continued effective management of aging effects for passive components.

The applicant has reported leakage from Conoseals at both IP2 and IP3 but there was no measurable material degradation on the vessel head as a result of the boric acid leakage. The applicant has stated that the most common cause of failure for bolts in the industry is boric acid corrosion which is documented in EPRI Mechanical Tools (EPRI 1010639) and Non-Class 1 Mechanical Implementation guidelines.

During the audit and review of this AMP, the staff asked the applicant whether they had observed leakage from Conoseal flanges (Audit Item 109). By letter dated March 24, 2008, the applicant stated that both IP2 and IP3 have experienced Conoseal leaks during the past few operating cycles. At IP2, the most recent leak occurred at penetration #95, during the current operating cycle. At IP3, the most recent leak was detected during the Spring 07 refueling outage. The applicant stated that the Conoseals at IP2 and IP3 have been modified to minimize the possibility of future leakage. All of the recent leaks have been eliminated with the exception of the current leak at Penetration #95. The applicant stated that the boric acid was cleaned up and the vessel head was examined for material degradation and that it did not detect any degradation in the areas exposed to boric acid deposits.

The staff verified that the applicant had taken appropriate corrective actions to clean off the boric acid residues that developed on the IP2 and IP3 upper reactor vessel (RV) heads as a result of Conoseal leakage. The staff also noted that applicant's corrective actions included an evaluation of the upper RV head wall thickness and that in the corrective actions documentation the applicant had demonstrated that the Conoseal leakage did not result in any detectable boric acid-induced wastage (i.e., loss of material degradation) in the upper RV closure heads. Based on this review, the staff finds that the applicant's program monitors for Conoseal leakage and that the applicant takes appropriate corrective actions when Conoseal leakage is detected.

By letter dated May 7, 2008, in RAI RCS-1, the staff inquired about other operating experience (condition reports that had been issued on boric acid leakage of ASME Code Class 1 components). By letter dated June 5, 2008, the applicant stated, in part, that the routine inspections of control rod drives, control rod drive mechanisms, resistance temperature devices, RV lower heads, RV bottom mounted instrumentation (BMI) nozzles, RV seal tables, RV fittings, and RV flux thimble tubes at IP2 and IP3 from 2001 – 2005 revealed indications of boric acid leakage that could potentially lead to loss of material due to boric acid corrosion. The applicant stated that it had taken appropriate corrective actions to correct the adverse conditions, including cleaning of the affected Class 1 areas to remove boric acid residues from the components, replacing leaking gaskets, repair of leaking welds or components, and revisions to the implementing procedures for foreign material (boric acid residue) control and for visual inspections of the RVs. The applicant stated that the components, after boric acid residue cleaning, were determined to be acceptable for further service.

The staff noted that the applicant's response indicates that the applicant's augmented Boric Acid Corrosion Prevention Program is achieving its function of monitoring and detecting evidence of borated reactor coolant leakage from the applicant's ASME Code Class 1 reactor coolant pressure boundary components, and that the applicant is taking appropriate corrective actions when borated reactor coolant leakage is detected as part of the applicant's implementation of the program.

Thus, the staff finds that the applicant has addressed relevant operating experience that is applicable to this AMP, and that, based on the applicant's detection of boric acid residues and corrective actions to correct adverse boric acid residue conditions, the applicant has demonstrated that the program is effective and will be capable of detecting borated reactor coolant leakage from ASME Code Class 1 reactor pressure boundary components and RV Conoseals during the period of extended operation. RAI RCS-1 is resolved with respect to operating experience that is relevant to this AMP.

Based on this review, the staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.4 and A.3.1.4, the applicant provided the UFSAR supplement for the Boric Acid Corrosion Prevention Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Boric Acid Corrosion Prevention Program, the staff finds that all program elements are consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Buried Piping and Tanks Inspection Program

Summary of Technical Information in the Application. LRA Section B.1.6 describes the Buried Piping and Tanks Inspection Program as a new program that will be consistent with GALL AMP XI.M34, "Buried Piping and Tanks Inspection."

The Buried Piping and Tanks Inspection Program includes (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel, gray cast iron, and stainless steel components. Preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings. Buried components are inspected when excavated during maintenance. If trending within the corrective action program finds susceptible locations, the areas with a history of corrosion problems are evaluated for the need for additional inspection, alternate coating, or replacement. The program applies to buried components in the following systems.

- safety injection
- service water
- fire protection
- fuel oil
- security generator
- city water
- plant drains
- auxiliary feedwater
- containment isolation support

Of these systems, only the safety injection system contains radioactive fluids during normal operations. Safety injection system buried components are stainless steel. This system uses stainless steel for its corrosion resistance.

By letter dated July 27, 2009, as clarified by letter dated August 6, 2009, the applicant submitted an amendment to the LRA which modified the Buried Piping and Tanks Inspection Program. This amendment was in response to recent operating history which involved a February 2009 leak on the return line to the condensate storage tank (CST) for Unit 2. As a result of this operating experience, the applicant plans to include a risk assessment to classify in-scope buried piping segments and buried tanks as high, medium, or low impact of leakage based on the safety classification, the hazard posed by the fluids in the piping and tanks, and the impact of leakage on reliable plant operation. The applicant will consider the piping or tank material of construction, soil resistivity, drainage, the presence of cathodic protection, and the type of coating for corrosion risk.

The applicant's modification to the Buried Piping and Tanks Inspection Program significantly increases the number of inspections of buried piping and tanks. Rather than conduct one inspection prior to entering the period of extended operation, consistent with the GALL Report where site-specific operating experience is not a factor, the applicant will conduct 15 periodic inspections for IP2 prior to entering the period of extended operation in 2013, and 30 periodic inspections for IP3 prior to entering the period of extended operation in 2015. Also, because of the recent leak in the CST return line, the applicant plans to conduct six additional inspections in 2009 at lower level elevations for the service water and auxiliary feedwater systems, based on a determination that these locations have the highest risk of corrosion due to their proximity to the water table.

The applicant stated that it will employ inspection methods with demonstrated effectiveness for detection of aging effects in buried components such as those currently being evaluated by the Electric Power Research Institute. One example is guided wave ultrasonic testing (UT). The applicant further stated that it is actively participating in the industry group established to address issues with degradation of buried components.

With respect to inspections to be performed during the period of extended operation, the applicant stated that the number of inspections and inspection frequency will be based on the results of the planned inspections prior to the period of extended operation, other applicable industry and plant-specific operating experience, and its risk assessment.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements and basis documents of the Buried Piping and Tanks Inspection Program to verify consistency with GALL AMP XI.M34. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that elements (1) through (6) are consistent with the corresponding elements in GALL AMP XI.M34. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

During the audit, the staff asked the applicant if any buried tanks are in scope for license renewal (Audit Item 110). By letter dated March 24, 2008, the applicant stated that the following tanks are buried and in scope for license renewal and are included in the Buried Piping and

Tanks Inspection Program:

- IP2 Fuel Oil Storage Tanks (21/22/23 FOST)
- GT1 Fuel Oil Storage North and South Storage Tanks
- IP2 Security Diesel Fuel Tank
- IP3 Appendix R Fuel Oil Storage Tank (EDG-33-FO-STNK)
- IP3 Security Propane Fuel Tanks (2 of them)
- IP3 Fuel Oil Storage tanks (EDG-31/32/33-FO-STNK).

The applicant's discovery of a leak in the CST return line was documented in NRC Inspection Report 05000247/2009002, dated May 14, 2009. As a result of this leak, the applicant revised its Buried Piping and Tanks Inspection Program, in a letter dated July 27, 2009, as clarified by letter dated August 6, 2009. The staff reviewed the revised program to assure acceptability of the revised inspection plans. The staff found that the applicant's enhanced inspection plans provide a significant increase in the number of locations to be examined prior to the period of extended operation, from one per unit to a combined total of 51 inspections for the two units. These inspections will focus on the buried piping and tanks that are within the scope of the Buried Piping and Tanks Inspection Program. The applicant plans to prioritize the inspection locations based on a risk assessment that identifies high, medium and low impact of leakage at that location based on the safety classification, the hazard posed by the fluid, the potential impact of leakage on reliable plant operation, and the corrosion risk of the location. As described by the applicant, the corrosion risk appears to consider those parameters that will reasonably characterize the corrosion likelihood for the location. Overall, the staff finds that this approach for determining the specific locations for inspection and the large increase in the number of locations to be inspected provide a significant enhancement in the program prior to entering the period of extended operation, beyond that described in the GALL Report. The staff finds that the scope of this enhancement is reasonable in light of the recent operating experience at IP.

In its letter of July 27, 2009, as clarified by letter dated August 6, 2009, the applicant stated that additional periodic inspections will be conducted during the first 10 years of the period of extended operation. The applicant further stated that the frequency and number of these periodic inspections will be determined based on the results of the inspections that will be conducted and completed prior to entering the period of extended operation, in addition to the risk assessment of the piping segments and tanks. The staff finds that the applicant's commitment to consider the results of the inspections conducted prior to the period of extended operation in its subsequent inspection program is reasonable.

The use of inspection methods with demonstrated effectiveness for detection of aging effects, as proposed by the applicant for inspections both prior to and during the period of extended operation, provides reasonable assurance of the effectiveness of the technique. Specifically, the technique is to be evaluated by a third party, the EPRI NDE Center, and would be demonstrated to be capable of detecting degradation (e.g., cracks, corrosion) in samples that are similar to the configuration and types of degradation that may be present at the IP site. The staff finds the use of inspection methods with demonstrated effectiveness to be an acceptable and appropriate aspect of this program.

The staff finds that with the numerous enhancements to the GALL Buried Piping and Tanks Inspection Program, the applicant's program is acceptable. The applicant has significantly increased the number of inspections of buried piping beyond that which is recommended in the

GALL Report AMP prior to entering the period of extended operation. In addition, the applicant's commitment to perform additional periodic inspections using inspection methods with demonstrated effectiveness during the first 10 years of the period of extended operation, with the frequency and priority of inspections to be determined based on operating experience and risk assessment of the piping segments and tanks, provides reasonable assurance that the applicant will be able to adequately manage the effects of aging of its buried piping and tanks during the period of extended operation.

Operating Experience. LRA Section B.1.6 states that the Buried Piping and Tanks Inspection Program is a new program. When implementing this new program the applicant will consider as its basis industry operating experience in the operating experience element of the GALL Report program description. IP plant-specific operating experience is consistent with the operating experience in the GALL Report program description.

The applicant stated that the IP program is based on the GALL Report program description, which in turn is based on industry operating experience, assurance that the Buried Piping and Tanks Inspection Program will manage the effects of aging so components continue to perform intended functions consistent with the CLB through the period of extended operation.

In Audit Item 110, the staff asked the applicant if IP2 or IP3 had to replace any buried piping or had to replace or repair any sections of buried pipe. In its response, dated March 24, 2008, the applicant stated that a review of site condition reports back to 2000 revealed that there have been two underground piping leaks that occurred on the auxiliary steam supply cross connect line between Unit 2 and Unit 3. This piping is nonsafety-related and is not within the scope of license renewal. The first leak occurred in 2002 and a condition report was written for this leak. The leak was repaired via the work control process. The applicant further stated that a second leak occurred in April 2007 and was documented in a condition report. This line has been excavated and replaced. The cause of the failure was determined to be advanced corrosion of the pipe due to moisture intrusion. This was caused by the pipe coating breaking down and insulation that was not sufficient for the task. After replacement, the pipe was reinsulated using a special high temperature moisture resistant material that was designed to prevent this type of corrosion in the future. The applicant stated that no other buried piping repair or replacement was identified during its review of operating experience.

By letter dated July 27, 2009, as clarified by letter dated August 6, 2009, the applicant identified additional operating experience concerning coating degradation identified during the fall of 2008, and a February 2009 leak on the return line to the CST on Unit 2.

During the fall of 2008, the applicant performed inspections of three 10-foot sections of Unit 2 CST piping and found damaged coating and two locations with minor coating defects. The damaged coating was repaired. Ultrasonic testing measurements confirmed that the pipe thickness remained at nominal thickness, within the manufacturer's tolerance.

In February 2009, the applicant identified a leak in the IP2 return line to the CST. The applicant stated that there was no safety significance to the leak because there was sufficient inventory for the CST to perform its intended function. The applicant stated that the leak occurred as a result of damage to the coating on the pipe, which it concluded occurred during original construction. In particular, the applicant concluded that the damage occurred because the construction installation specification did not specify the type of backfill for covering the pipe, permitting rocks in the backfill. The location of the leak was close to the water table, and moisture in the soil may have contributed to the damage. The applicant replaced the section of pipe containing the leak and repaired several additional thinned areas on the pipe. The affected areas were recoated and the applicant used improved backfill specifications to cover the pipe. The staff at headquarters coordinated with NRC Region I inspectors who followed up on the licensee's corrective actions on site.

Based on its review, the staff concludes that the applicant has appropriately considered operating experience for the Buried Piping and Tanks Inspection Program. Further, the staff concludes that the applicant's "operating experience" program element satisfies the criterion defined in the GALL Report and in SRP-LR Section A.1.2.3.10. The staff finds this program element to be acceptable.

UFSAR Supplement. In LRA Sections A.2.1.5 and A.3.1.5, the applicant provided the UFSAR supplement for the Buried Piping and Tanks Inspection Program. The applicant committed to implement the Buried Piping and Tanks Inspection Program prior to the period of extended operation. The applicant further stated that this new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M34, "Buried Piping and Tanks Inspection" (Commitment 3). By letter dated July 27, 2009, as clarified by letter dated August 6, 2009, the applicant modified Commitment 3 to include a risk assessment of in-scope buried piping and tanks that includes consideration of the impacts of buried piping or tank leakage and of conditions affecting the risk for corrosion. The applicant changed the inspections from "opportunistic" to periodic, and committed to establish the inspection priority and frequency based, in part, on the results from its planned inspections prior to entering the period of extended operation and other applicable industry and plant-specific operating experience. Further, the applicant committed to perform inspections using inspection methods with demonstrated effectiveness. The applicant also modified LRA Sections A.2.1.5, A.3.1.5, and B.1.6 to incorporate the changes to the Buried Piping and Tanks Inspection Program.

The staff reviewed these sections, as revised, and determines that the information provided in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

By letter dated July 27, 2009, as clarified by letter dated August 6, 2009, the applicant added a new commitment (Commitment 40) that states that plant specific and appropriate industry operating experience will be evaluated and lessons learned will be used to establish appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs.

Conclusion. On the basis of its audit and review of the applicant's Buried Piping and Tanks Inspection Program, the staff finds that all program elements are consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Containment Leak Rate Program

Summary of Technical Information in the Application. LRA Section B.1.7 describes the existing Containment Leak Rate Program as consistent with GALL AMP XI.S4, "10 CFR 50,

Appendix J."

The applicant states that the Containment Leak Rate Program, as described in 10 CFR Part 50, Appendix J, requires containment leak rate tests to assure that (a) leakage through primary reactor containment, and systems and components penetrating primary containment shall not exceed allowable values specified in technical specifications or their bases and (b) periodic surveillance of reactor containment penetrations and isolation valves is performed so that proper maintenance and repairs are made during the service life of containment, and systems and components penetrating containment. The applicant furthers states that the IP2 and IP3 program utilizes 10 CFR 50 Appendix J, Option B, and the guidance in RG 1.163, and the recommendations in NEI 94-01.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Containment Leak Rate Program and basis documents to verify consistency with GALL AMP XI.S4. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that elements (1) through (6) are consistent with the corresponding elements in GALL AMP XI.S4. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

Operating Experience. LRA Section B.1.7 states that in 2006 (Unit 2 refueling outage 17, 2R17), containment leak rate testing at IP2 was completed successfully. The applicant states that a QA surveillance of the containment leak rate test found only administrative deficiencies in the procedures for calculating total leakage. Results from the 2005 (Unit 3 refueling outage 13, 3R13) IP3 containment leak rate testing were satisfactory. Confirmation of containment integrity, along with detection and resolution of program discrepancies, assure effective program management of loss of component material.

The applicant also states that an industry benchmarking for this program in 2004 found areas for improvement and implemented corrective actions. A 2003 self-assessment of the program focused on differences between the IP2 and IP3 program procedures and took actions that led to several improvements.

The applicant concluded that its program is consistent with the GALL Report, Option B program, stating that review of operating history, corrective actions, and self-assessments shows the Containment Leak Rate Program is monitored and enhanced continually to incorporate operating experience and is effective in ensuring the structural integrity and leak tightness of the IP2 and IP3 containments.

During an onsite audit, the staff reviewed the program basis documents discussion of operating experience, which summarize the operating experience of the Containment Leakage Rate Program, as well as the results of past leakage rate tests of the containment at IP2 and IP3. In addition, the documents describe other industry benchmarking and focused self-assessment of the Containment Leakage Rate Program.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.6 and A.3.1.6, the applicant provided the UFSAR supplement for the Containment Leak Rate Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Containment Leak Rate Program, the staff finds that all program elements are consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Environmental Qualification of Electric Components Program

Summary of Technical Information in the Application. LRA Section B.1.10 describes the existing Environmental Qualification of Electric Components Program as consistent with the GALL Report AMP X.E1, "Environmental Qualification (EQ) of Electric Components."

The applicant stated that the Environmental Qualification of Electric Component Program is an existing program. The NRC has established nuclear station EQ requirements in 10 CFR Part 50, Appendix A, Criterion 4, and 10 CFR 50.49. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electric components located in harsh environments (that is, those areas of plant that could be subject to the harsh environmental effects of a loss of coolant accident (LOCA), high energy line breaks (HELBs) or high radiation) are qualified to perform their safety function in those harsh environments. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of EQ. The applicant further stated that the IP EQ program manages the effects of thermal, radiation, and cyclic aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components are refurbished, replaced, or their qualification is extended prior to reaching the aging limits established in the evaluation. Aging evaluations for EQ components are TLAAs for license renewal.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Environmental Qualification of Electric Components Program and basis documents to verify consistency with the GALL Report AMP X.E1. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that elements (1) through (6) are consistent with the corresponding elements in the GALL Report AMP X.E1. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

Operating Experience. LRA Section B.1.10 states that in August 2001, the applicant identified incorrect inputs in the EQ analyses. As part of its corrective actions, the applicant stated that it updated calculations and evaluated other program documents and environmental conditions. The applicant also stated that, in July 2002, a QA audit of the program found differences between the analytical tools for high-energy line break analyses at IP2 and IP3. As part of corrective actions, the applicant developed revised pressure-temperature (P-T) profiles and thermal lag evaluations for specific equipment and revised the EQ program plan and supporting calculations. The applicant further stated that a focused self-assessment in 2002 found that program procurement and work control processes complied with 10 CFR 50.49 and that in February 2003, the EQ program was reviewed to determine the impact of the IP2 power uprate. Those EQ files which required update were revised. In 2003-2004, an EQ master list validation project led to wiring diagram reviews and master list updates.

The staff interviewed the applicant's technical staff and reviewed the program basis documents. During the discussion of the EQ program with the applicant, the staff requested the applicant to provide additional operating experience (OE) associated with the EQ program (Audit Item 160). In a letter dated March 24, 2008, the applicant stated that in January 2006, during an EQ program enhancement project, it discovered that an EQ file did not identify or address qualification of pigtail extension cables. A condition report (CR) was initiated to capture EQ documentation deficiency. The EQ program enhancement project was initiated to correct this type of discrepancy and test reports were obtained and evaluated. The applicable test report met the applicant’s environmental parameter requirements; therefore, these cables were considered qualified.

The applicant further stated that it participates in several industry-based working and assessment groups, to ensure that the IP2 and IP3 EQ program stays current with the industry and that the industry OE is addressed. The industry groups are comprised of utility operators worldwide, the majority of which are in the US and Canada. Participation in these organizations also provides a source of regulatory and reference documents, component information, engineering analyses, and material data from many different manufacturers and utilities.

The staff finds that the operating experiences identified above and those identified in program basis documents demonstrate that identification of program weakness and timely corrective actions as part of the EQ program provide assurance that program will remain effective in assuring that equipment is maintained within its qualification basis and qualified life.

The staff confirmed that the “operating experience” program element meets the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.9 and A.3.1.9, the applicant provided the UFSAR supplement for the Environmental Qualification of Electric Components Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant’s Environmental Qualification of Electric Components Program, the staff finds that all program elements are consistent with the GALL Report AMP X.E1. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB, for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Flow-Accelerated Corrosion Program

Summary of Technical Information in the Application. LRA Section B.1.15 describes the existing Flow-Accelerated Corrosion (FAC) Program as consistent with GALL AMP XI.M17, "Flow-Accelerated Corrosion."

The Flow-Accelerated Corrosion Program applies to safety-related and nonsafety-related carbon and low-alloy steel components in systems containing high-energy fluids which carry two-phase or single-phase high-energy fluid for more than 2 percent of plant operating time. The program, based on EPRI guidelines in Nuclear Safety Analysis Center (NSAC)-202L-R2,"Recommendations for an Effective Flow-Accelerated Corrosion Program," (April 1999) for an effective Flow-Accelerated Corrosion program, predicts, detects, and monitors flow-accelerated corrosion in plant piping and other pressure-retaining components. This program includes (a) an evaluation to determine critical locations, (b) initial operational inspections to determine the extent of thinning at these locations, and (c) follow-up inspections to confirm predictions or to repair or replace components as necessary.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Flow-Accelerated Corrosion Program and basis documents to verify consistency with the GALL Report AMP XI.M17. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that elements (1) through (6) are consistent with the corresponding elements in the GALL Report AMP XI.M17. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the "corrective actions" program element for this AMP with respect to verifying whether repair/replacement activities for in-scope components involved replacement with components using FAC-resistant materials. The staff reviews this aspect of the "corrective actions program element later in the evaluation of the applicant response to Part 2 of RAI B.1.15-2.

However, during its review of the applicant's program, the staff identified the following aspects that needed additional clarification: (1) the scope of the applicant's program, (2) evaluation of the exception in the program to use EPRI Report NSAC-202L-R3, "Recommendations for an Effective Flow-Accelerated Corrosion Program," (May 2006) as the implementation guideline document for the applicant's program, (3) resolution of RAI B.1.15-1 on whether the AMRs in the LRA credit this program to manage loss of material due to flow-accelerated corrosion for the carbon steel components in the steam generator (SG) blowdown system, and (4) resolution of RAI B.1.15-2, Parts 1, 2, and 3, on how CHECWORKS modeling is performed, how power uprate conditions are incorporated into this modeling, and on which in-scope systems at IP2 and IP3 are considered as being the most susceptible to flow-accelerated corrosion. The staff evaluates these aspects of the applicant's program in the italicized subsections that follow.

Clarification on the Scope of Program

The NRC discussed the establishment and implementation of Flow-Accelerated Corrosion Programs in NRC Bulletin 87-01, "Thinning of Pipe Walls in Nuclear Power Plants" (July 9, 1987) and in Generic Letter (GL) 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning" (May

2, 1989). The staff verified that the applicant responded to Bulletin 87-01 for IP2 in a letter dated September 11, 1987 (NRC Microfiche Address 42741, Pages 199-233) and for IP3 in a letter dated September 15, 1987 (NRC Microfiche Address 42739, Pages 131-146). The staff verified that the applicant responded to GL 89-08 for IP2 in a letter dated July 20, 1989 (NRC Microfiche Address 50726, Pages 331-332) and for IP3 in a letter dated July 21, 1989 (NRC Microfiche Address 50737, Pages 100-102). The staff verified that these responses were the docketed documents that initially defined the systems that are within the scope of the applicant's Flow Accelerated Corrosion Programs for IP2 and IP3, and defined how the programs would be implemented. The staff verified that the scope of the applicant's Flow-Accelerated Corrosion Program includes these generic communication responses.

In the "operating experience" program element in GALL AMP XI.M17, "Flow Accelerated Corrosion," the staff clearly identified that single-phase feedwater and condensate systems and two-phase extraction steam, moisture separator reheater drain, and feedwater heater drain systems are among the PWR plant systems that are the most susceptible to loss of material (erosion) by flow-accelerated corrosion. From its review of the applicant's responses to Bulletin 87-01 and GL 89-08 for IP2 and IP3, the staff verified that the scope of the programs for IP2 and IP3 includes those systems that contain carbon steel or alloy steel components that are exposed to high velocity, single-phase water-based flow environment or high velocity, two-phase water-steam environments, and, as a minimum, the feedwater, condensate, extraction steam, moisture separator reheater drain, and feedwater heater drain systems, as recommended for inclusion in the AMP according to the "operating experience" and "reference" sections of GALL AMP XI.M17, "Flow-Accelerated Corrosion." The staff also noted from the applicant's responses to these generic communications, that the programs developed in response to Bulletin 87-01 and GL 89-08 includes the following additional systems:

- Auxiliary feedwater systems (as indicated in the Bulletin 87-01 response for IP2 and the GL 89-08 response for IP3)
- Steam generator (SG) blowdown systems (as indicated in the Bulletin 87-01 response for IP2 and the GL 89-08 response for IP3)
- Turbine generator cross-under piping, including pre-separators (as indicated in the Bulletin 87-01 response for IP2)
- Heater drain pump discharge piping (as indicated in the Bulletin 87-01 response for IP2)
- Main steam system (as indicated in the GL 89-08 response for IP3)
- Reheater drain system (as indicated in the GL 89-08 response for IP3)
- Auxiliary Steam System (as indicated in the GL 89-08 response for IP3)

The staff finds that the inclusion of these additional systems within the scope of the applicant's program is acceptable because it represents an additional scoping conservatism in the program beyond the feedwater, condensate, extraction steam, moisture separator reheater drain, and feedwater heater drain systems that were included in the program in response to the NRC's safety-significant FAC-related generic communications that have been identified in "operating experience" program element of GALL AMP XI.M17.

Based on this review, the staff finds that the scope of program element for the Flow-Accelerated Corrosion Program is acceptable because: (1) the scope of the program includes the applicant's responses to Bulletin 87-01 and GL 89-08, (2) the scope of the program includes the feedwater, condensate, extraction steam, moisture separator reheater drain, and feedwater heater drain systems, which are the plant systems that the staff has identified as being highly susceptible to loss of material by flow-accelerated corrosion, (3) the scope of the program includes additional plant systems that the applicant has also identified as being potentially susceptible to flow-accelerated corrosion, and (4) the scope of the program is consistent with NRC-identified, industry-identified, IP2-specific, and IP3-specific operating experience.

Exception to use EPRI Report NSAC-202L-R3

The staff noted that in the “scope of program” and “detection of aging effects” program elements of GALL AMP XI.M17, “Flow-Accelerated Corrosion,” the staff recognizes EPRI Report NSAC-202L-R2 as a suitable guidance document for implementing flow-accelerated corrosion programs. The staff also noted that the applicant indicated that, instead of using Revision 2, Entergy is implementing Revision 3 for implementation of the applicant’s program, and that the applicant did not identify this inconsistency as an exception to the “scope of program” and “detection of aging effects” program elements of GALL AMP XI.M17.

In Audit Item 156, the staff asked the applicant to justify its use of Revision 3, and why the use of the later version of the report was not indentified as an exception to the aging management criteria that are given in the “scope of program” and “detection of aging effects” program elements of GALL AMP XI.M17. By letter dated December 18, 2007, the applicant stated that the changes made from NSAC-202L-R2 to NSAC-202L-R3 basically accomplished the following improvements in the report that made for better FAC-management guidance on the “scope of program” and “detection of aging effects” program elements for the AMP:

1. “scope of program” – (1) administrative relocation of the guidance for system selection within the scope of the program, (2) reorganization of the guidance for selecting components for inspection for those systems that are within the scope of the program, (3) enhancement of the guidance for component sample selection to provide clarification and details on sample selection for both modeled piping lines and non-modeled piping lines that are within the scope of the program, (4) addition of enhanced guidance for using plant-specific and industry-generic operating experience as an additional basis for selecting components for inspection, and (5) improved, enhanced guidance for sample expansion upon detection of relevant FAC-induced indications.

2. “detection of aging effects” – (1) additional clarification on the use of volumetric inspection techniques, including UT and radiographic testing (RT) for the detection of loss of material as a result of FAC, (2) additional guidance for the inspection of in-scope vessels and tanks, (3) enhancement of the inspection guidance for turbine cross-around piping, valves, orifices and flow elements, and (4) additional guidance of the basis for the use of RT as an volumetric technique for large bore piping.

The staff verified that the updated guidance in NSAC-202L-R3 did not change: (1) the guidelines basis for excluding components from examination based on their materials of fabrication and material alloying contents, operational characteristics (for components not in service or infrequently in service), the dissolved oxygen contents of the single-phase or two-phase environments that the components are subjected to, or the flow velocities for the single-phase or two-phase environments that the components are subjected to, (2) the UT inspection criteria in NSAC-202L-R2 that components to be inspected around their girths and over a distance equivalent to least ± two pipe diameters of the subject welds or components scheduled for inspection, (3) the minimum wall thickness acceptance criteria for in-scope components, and (4) the repair/replacement criteria for components that do not meet the acceptance criteria of the report.

The staff also noted that the stated changes to the EPRI NSAC report provide for better programmatic guidance because they: (1) provide for enhanced guidance on how to apply relevant industry experience and plant-specific experience as an additional basis for selecting and scheduling additional components for UT or RT inspection, (2) provide for enhanced guidance on sample expansion if relevant indications of loss of material by flow-accelerated corrosion or other loss of material mechanisms are detected, (3) provide for enhanced guidance for inspection of in-scope tanks, cross-around piping, and small bore piping, and (4) provide addition clarifications on how to apply UT and RT as a volumetric inspection techniques for these programs.

The staff verified that, in the applicant's letter of December 18, 2007, the applicant amended the "scope of program" and "detection of aging effects" program elements in AMP B.1.15, Flow-Accelerated Corrosion Program, to identify use of EPRI Report NSAC-202L-R3 as an exception to the implementation guidance document that is recommended in the "scope of program" and "detection of aging effects" program elements of GALL AMP XI.M17, "Flow-Accelerated Corrosion." Thus, based on this review, the staff finds that EPRI Report NSAC-202L-R3 is an acceptable alternative and updated version of the EPRI NSAC guidelines for managing loss of material due to flow-accelerated corrosion at IP2 and IP3 because: (1) the updated version of the report in EPRI Report NSAC-202L-R3 has not led to any non conservatisms in the report's core guidance recommendations for inspecting of in-scope carbon steel or low-chromium content alloy steel components, for establishing the acceptance criteria for these components, or for repairing or replacing components if unacceptable indications of loss of material are detected in the components, and (2) the staff has verified that the applicant has amended the LRA to identify the use of EPRI Report NSAC-202L-R3 as an exception to the "scope of program" and "detection of aging effects" program elements in GALL AMP XI.M17. NRC Audit Item 156 is resolved.

Resolution of RAI B.1.15-1

The staff also noted that in the AMR items for the LRA, the applicant credited only its Water Chemistry Control-Primary and Secondary Program for managing loss of material in the steam generator blowdown nozzle carbon steel interior surface. In RAI B.1.15-1, dated December 7, 2007, the staff questioned whether degradation of these nozzles would be more appropriately managed by the Flow-Accelerated Corrosion Program.

In its response, dated January 4, 2008, the applicant stated that "[t]he blowdown system piping external to the steam generators is susceptible to loss of material due to flow accelerated corrosion and is managed by the Flow Accelerated Corrosion Program. The steam generator blowdown nozzles are part of the blowdown system piping and are included in the FAC program."

In addition, the applicant stated that the corresponding AMR entries to LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3 would be revised to include a statement in Table 3.1.1 AMR Item 3.1.1-59 that will state that the carbon steel steam generator (SG) blowdown pipe connection is susceptible to FAC and that the Flow-Accelerated Corrosion Program is credited to manage loss of material due in these components.

The staff verified that the applicant amended the LRA by letter dated January 4, 2008, to: (1) amend the applicable AMRs for carbon steel SG blowdown piping to identify loss of material due to flow-accelerated corrosion as an applicable aging effect requiring management (AERM) for the interior piping surfaces that are exposed to treated water, (2) amend the applicable AMRs to credit the Flow-Accelerated Corrosion Program for management of this aging effect, and (3) amend AMP B.1.15, Flow-Accelerated Corrosion Program to bring the SG blowdown piping system within the scope of the AMP. Based on the applicant's explicit inclusion of the above components in the Flow-Accelerated Corrosion Program, the staff finds the applicant's response to RAI B.1.15-1 to be acceptable because the applicant has amended the scope of the Flow-Accelerated Corrosion program to include the SG blowdown piping system, and because the applicant has amended its AMRs to include AMRs on loss of material due to flow-accelerated of the carbon steel or alloy steel SG blowdown system piping, piping components, and pipe fittings that credit this program for aging management. The staff's concern described in RAI B1.15-1 is resolved.

Based on this review, the staff finds that the "scope of program" program element for the Flow-Accelerated Corrosion Program is acceptable because: (1) the applicant has identified components within the scope of the program are those carbon steel/low chromium-content alloy steel plant components that are in systems within the scope of license renewal and are subject to high-velocity/high energy single-phase or two-phase aqueous environments, (2) the program, as amended, is consistent with the program element criteria in GALL AMP XI.M17.

Resolution of RAI B.1.15-2, Parts 1, 2, and 3

The staff noted that IP2 and IP3 have implemented stretch power uprates (SPU) within the last three years. To assess the impact that these SPUs would have on the modeling and predictions of the CHECWORKS™ program, the staff issued RAI B.1.15-2 on December 7, 2007 to the applicant. In this three part RAI, the staff asked the applicant to: (1) provide details on any changes made to the Flow Accelerated Corrosion Program in order to account for changes that would need to be made to the process variables in CHECWORKS™ as a result of implementing these SPUs, (2) identify those in-scope piping systems and components that are currently most susceptible to loss of materials by flow-accelerated corrosion, and (3) clarify how accurately the CHECWORKS™ model has predicted changes in FAC wear rates for the top four most susceptible systems/components in each unit since the time the SPUs were implemented.

The applicant responded to RAI B.1.15-2 in a letter dated January 4, 2008. With respect to the applicant response to Part 1 of the RAI, the applicant stated that inputs to the IP2 and IP3 Flow-Accelerated Corrosion Programs were updated to include SPU operating parameter changes (*e.g.*, flow rates and operating temperatures), in addition to incorporating the results of previous wall thickness measurements into the CHECWORKS™ modeling to allow for updated FAC-induced wear rate predictions. The staff verified that the applicant's revised program used the CHECWORKS™ program as one of several bases for establishing which in-scope piping component locations should be scheduled for inspection at the next outage. The staff also verified that the applicant uses IP2-specific and IP3-specific operating experience, operating experience discussed in NRC generic communications, industry operating experience records or reports, and engineering judgment as additional bases for selecting in-scope piping components for inspection. The staff also verified that the applicant's use of the CHECWORKS™ program uses the most recent updated power-uprated operating parameters and the most current inspection results obtained from past inspections performed on components as the basis for establishing the program wear predictions for ferritic steel components that are within the scope of the program. Thus, the staff finds that the applicant has provided an acceptable basis for using CHECWORKS™ as one of several means for identifying components for inspection and for scheduling components for inspection at the next unit refueling outage because the current predictions from the computer model are based on the power uprated conditions and the most current inspection results for systems and components that are within the scope of and have been modeled by CHECWORKS™. Part 1 of RAI B.1.15-2 is resolved.

With respect to the applicant's response to Part 2 of RAI B.1.15-2, the applicant stated that the extraction steam system lines at IP2 and IP3 are the most susceptible plant systems for flow-accelerated corrosion, with the 3rd point extract steam lines between the high pressure turbines and the #23 feedwater heater being the most susceptible lines for IP2, and the 5th point extraction steam lines between the pre-separators and the #35 feedwater heater being the most susceptible lines for IP3. The staff finds that this is acceptable because it is consistent with the staff's operating experience discussions in NRC Information Notices (INs) 89-53 and 97-84 that FAC-induced full ruptures of extraction steam systems have occurred in the industry and that these systems are among plant systems most susceptible to FAC-induced erosion (i.e. loss of material due to FAC).

The applicant also clarified the majority of the most susceptible plant locations at IP2 and IP3 have been replaced with FAC-resistant materials. The staff verified that the applicant identifies (in the "operating experience" program element for this AMP) that the FAC-resistant materials are chromium-molybdenum (Cr-Mo) alloy steels. The staff noted that in EPRI Report No. NSAC-202L-R2 (which is endorsed in GALL AMP XI.M17) and in EPRI Report No. NSAC-202L-R3.(which is the version of the report currently being used by the applicant, and found to be an acceptable alternative by the staff), EPRI identifies that austenitic stainless steels or chromium-molybdenum (Cr-Mo) alloy steels with chromium alloying contents in excess of 0.75% Cr by weight are steel materials that have enhanced resistance to FAC-induced erosion (i.e. loss of material due to FAC). The staff finds that the applicant's basis for replacing susceptible components with Cr-Mo alloy steels is acceptable because, in the staff's endorsement of EPRI Report NSAC-202L-R2, the staff concurred that Cr-Mo alloy steels provide for added corrosion resistance to FAC. Thus, based on this review, the staff finds that the applicant has resolved Part 2 of RAI B.1.15-2 because: (1) the applicant's statement that the extraction steam systems are the plant systems most susceptible to flow-accelerated corrosion is consistent with the staff's discussions in INs 89-53 and 97-84 that extraction steam systems are among the plant systems that are most susceptible to FAC-induced erosion, and (2) the applicant has provide an acceptable basis for replacing susceptible components (including any components that have been identified to have an unacceptable amount of FAC-induced aging in them) with Cr-Mo alloy steel in-kind components. Part 2 to RAI B.1.15-2 is resolved.

With respect to the applicant's response to Part 3 of RAI B.1.15-2, the applicant provided the following clarification on how the CHECWORKS™ modeling accounted for SPU conditions and why prolonged benchmarking of the models predictive analytical modeling was not necessary:

> The input to the CHECWORKS modeling program includes plant operating parameters such as flow rates, operating temperatures and piping configuration, as well as measured wall thicknesses from FAC program components. This input, in conjunction with the CHECWORKS predictive algorithm, is used to predict the rate of wall thinning and remaining service life on a component-by-

> component basis. The value of the model lies in its ability to predict wear rates based on changing parameters, such as flow rate, without having to have actual measured wall thickness values. The predictive algorithms built into CHECWORKS are based on available laboratory data and FAC data from many plants. CHECWORKS was designed, and has been shown, to handle large changes in chemistry, flow rate and or other operating conditions. In its use throughout the industry, the CHECWORKS model has been benchmarked against measurements of wall thinning for components operating over a wide range of flow rates. Consequently, the validity of the model does not depend on benchmarking against plant-specific measured wear rates of components operating under SPU conditions. In addition, by the time IPEC enters the period of extended operation (in the year 2013), inspection data under SPU conditions will have been obtained. These additional data sets, when added to the CHECWORKS database, will result in more refined wear rate predictions. Since the previously most susceptible locations have been replaced, wear rates are low. Due to the low wear rates, the small changes in operating parameters due to SPU, and the relatively short time since SPU, changes to wear rates since SPU will be very small. The accuracy of the model is not expected to change significantly due to the SPU.

The staff noted that the applicant's response to RAI B.1.15-2 clearly explains how the CHECWORKS™ computer code is used as an analytical model for predicting which plant system and components should be inspected during scheduled outages in which the applicant can perform UT examinations of the components. With respect to the use of CHECWORKS™ as a predictive model, the staff noted that the CHECWORKS™ analytical model uses the actual configured plant design, plant operating characteristics and parameters (such as system operating temperature flow rates, pressure, and water chemistry values), and actual UT inspection results to establish a susceptibility ranking of the plant's steel components to wall thinning by flow-accelerated corrosion.

The staff also noted the modeling includes a feature to incorporate actual inspection wall thickness results back into the computer modeling, and that this feature is used to accomplish two important aspects of CHECWORKS™ predictive modeling capability: (1) it permits the user to compare that actual as-found wall component thickness measurements of an inspected component to the wall thickness for the component that was predicted by CHECWORKS™ in the previous modeling results, thus providing a method for confirming the degree of accuracy of the model's previous component wear rate predictions and component wall thickness predictions, and (2) it permits the user to perform re-baselined component wear rate predictions and component wall thickness predictions based on the incorporation of the compiled inspection data for components that are modeled by the computer code and are inspected as part of the applicant's Flow-Accelerated Corrosion Program. The staff considers this feature to be a self-benchmarking capability of the CHECWORKS™ model. The staff also verified that the applicant's implementation of the CHECWORKS™ computer code applies all of these features and that the modeling has incorporated the operating conditions and parameters from the IP2 and IP3 stretch power uprates.

The staff noted that CHECWORKS™ is endorsed in EPRI Report Nos. NSAC-202L-R2 and EPRI Report No. NSAC-202L-R3 only as one of a number of methods that should be used to predict which plant components are susceptible to FAC and which components should be inspected at scheduled refueling outages or replaced with in-kind components using

FAC-resistant materials. The staff noted that these reports also state the relevant operating experience and engineering judgment are both invaluable additional tools that should used in establishing which components should be scheduled and inspected for wall thickness measurements. The staff verified that, in addition to use of CHECWORKS™, the applicant also uses IP2-specific and IP3-specific operating experience, industry-wide operating experience, operating experience identified in NRC-issued INs, GLs, and Bulletins, and engineering judgment as additional bases for selecting the steel piping, piping components, and piping elements for inspection. The staff also verified that the Flow-Accelerated Corrosion Program includes applicable acceptance criteria for evaluating in-scope components and applicable corrective actions (repair, replacement, or re-evaluation) for components that are projected to exhibit an unacceptable amount of FAC-induced wall thinning.

Since the applicant's program includes the incorporation of actual wall thickness measurement data into the CHECWORKS™ modeling, since the staff considers CHECWORKS™ to be a self-benchmarking compute code, and since the applicant does not limit CHECWORKS™ as being the only programmatic basis for selecting and scheduling components for inspection, the staff finds that it is unnecessary to require prolonged benchmarking of the CHECWORKS™ computer code in order to justify its use in the selection and scheduling of in-scope components for inspection. In addition, the staff has verified that the applicant's implementation of CHECWORKS™ as part of the applicant's program is consistent with the staff's recommendation in the "monitoring and trending" program element in GALL AMP XI.M17 that CHECWORKS™ be used as one of the bases for selecting and scheduling in-scope components for inspection. Based on this review, the staff finds that this approach for aging management of loss of material due to flow-accelerated corrosion is acceptable because it provides an adequate basis why prolonged benchmarking of CHECWORKS™ is unnecessary and because the applicant's implementation of CHECWORKS™ is in conformance with the staffs "monitoring and trending" program element criteria for aging management that are recommended in GALL AMP XI.M17, "Flow-Accelerated Corrosion." RAI B.1.15-2, Part 3 is resolved.

Based on this review, the staff concludes that the program elements for the applicant's Flow-Accelerated Corrosion Program, as amended, provide an adequate basis to manage flow-accelerated corrosion because: (1) CHECWORKS™ code is considered to be a self-benchmarking code that is capable of modeling, predicting, and tracking the results of the ultrasonic inspections that are performed in accordance with the applicant's Flow-Accelerated Corrosion Program, (2) the self-benchmarking feature of CHECWORKS™ makes prolonged benchmarking of CHECWORKS™ is unnecessary, (3) the applicant uses the actual UT inspection results to confirm the predictive modeling of the CHECWORKS™ analyses and to perform re-baselined CHECWORKS™ predictive analyses, (4) the applicant does not limit the use of the CHECWORKS™ computer code as the sole basis for establishing which steel piping, piping components, or piping elements at IP2 and IP3 will be inspected, and (5) the program includes acceptable program elements for managing flow-accelerated corrosion that are consistent with the program element criteria in GALL AMP XI.M17 or with the acceptable alternative to use EPRI Report NSAC-202L-R3 as the implementation guideline for this program.

Operating Experience. LRA Section B.1.15 states that the most recent updates of the respective CHECWORKS FAC models account for IP2 and IP3 operating experience, including inspection data from the outage inspections as well as the changes to FAC wear rates, due to the recent power uprates. These updates further calibrate the model; and, therefore, improve the accuracy of the wear predictions.

The applicant stated that the IP2 Flow-Accelerated Corrosion Program was audited in 2004. The audit team found this program effective and in compliance with NRC regulations, ASME code, EPRI standards, and Institute of Nuclear Power Operations (INPO) guidelines. Program compliance with industry standards and guidelines assures continued effective management of aging effects for passive components.

In the LRA, the applicant stated that in February 2006, it performed a self-assessment of the Flow-Accelerated Corrosion Program to evaluate its overall health and effectiveness. The assessment team concluded that the applicant has a well-organized and effective Flow-Accelerated Corrosion Program, consistent with the primary industry standards, and with no weaknesses or deficiencies that would indicate any negative impact on long-term monitoring of flow-accelerated corrosion.

Further, the applicant stated that in March 2005, during the 3R13 refueling outage, it detected wall thinning on vent chamber drain and high-pressure turbine drain components, which were replaced during that outage. The applicant stated that these systems are susceptible to flow-accelerated corrosion and are closely monitored. Susceptible sections of these systems are replaced with FAC-resistant chrome-moly material. All remaining inspected components were found acceptable for continued service. In May 2006, during the 2R17 refueling outage, the applicant detected wall thinning in a steam trap pipe, which was then replaced during that outage. The applicant concluded that detection of degradation and corrective action prior to loss of intended function assure effective program management of aging effects due to flow-accelerated corrosion.

As part of the development of a fleet-wide program procedure, Entergy performed a review of best practices for the Flow-Accelerated Corrosion Program at all Entergy sites. Guidance from the EPRI CHECWORKS™ User's Group was applied to this procedure. Program compliance with industry standards and use of fleet-wide best practices in the development of procedures assure continued effective management of aging effects for passive components.

The staff noted that relevant FAC-related operating experience for PWR facilities has been provided in the NRC INs, Bulletins, and GLs that are given in the "operating experience" and "reference" sections in GALL AMP XI.M17, "Flow-Accelerated Corrosion." The staff verified, through its review of the applicant's responses to Bulletin 87-01 and GL 89-08, that the applicant's program includes those plant systems that are addressed in these NRC generic communications. Based on this determination, the staff finds that this provides evidence that the applicant adjusts its program to account for relevant operating experience.

The staff also noted that one of the requests made in Bulletin 87-01 was for applicants to summarize the FAC-based inspections that they had performed prior to issuance of the bulletin on May 2, 1987. The staff verified that in the applicant's responses to Bulletin 87-01, the applicant provided a summary of the UT inspections that had been performed at IP2 and IP3 prior to issuance of the bulletin. The staff noted that in the applicant's summary of its inspection results, the applicant had provided both the nominal wall thicknesses and the as-found wall thicknesses of the components that had been inspected prior to Bulletin 87-01. The staff also noted that in the applicant's bulletin responses, the applicant had indicated those components that were scheduled for repair or replacement as a result of detection of an unacceptable degree of FAC-induced degradation in the components or because the existing amount of degradation in the components was projected to grow to an unacceptable level prior to the next outage in which re-inspections would be performed. Based on this information, the staff finds that the inspection results in the bulletin responses demonstrate that the applicant is appropriately performing UT inspections of the systems that include carbon steel or alloy steel components which are potentially susceptible to flow-accelerated corrosion and that the applicant takes appropriate corrective action to repair or replace those components based on relevant IP2 and IP3 FAC-related operating experience.

Based on its review of the applicant responses to Bulletin 87-01 and GL 89-08, and of relevant IP2-specific and IP3-specific operating experience and operating experience discussed in applicable FAC-related NRC generic communications, the staff concludes that the applicant appropriately assesses and adjusts its Flow-Accelerated Corrosion Program to account for relevant FAC-related operating experience and to adjust the "scope of program" and remaining program elements for the AMP in accordance with lessons learned from this operating experience.

Based on this review, the staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

<u>UFSAR Supplement</u>. In LRA Sections A.2.1.14 and A.3.1.14, the applicant provided the UFSAR supplements for the Flow-Accelerated Corrosion Program. By letter dated December 18, 2007, the applicant revised LRA Sections A.2.1.14, A.3.1.14, and B.1.15 to change the reference from NSAC-202L-R2 to NSAC-202L-R3. The staff reviewed these sections, as revised, and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its audit and review of the applicant's Flow-Accelerated Corrosion Program, the staff finds that all program elements are consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Non-EQ Inaccessible Medium-Voltage Cable Program

<u>Summary of Technical Information in the Application</u>. LRA Section B.1.23 describes the Non-EQ Inaccessible Medium-Voltage Cable Program as a new program that will be consistent with the GALL Report AMP XI.E3, "Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

The applicant stated that the Non-EQ Inaccessible Medium-Voltage Cable Program includes periodic inspections for water collection in cable manholes and tests cables. In-scope medium-voltage cables (*i.e.*, cables with operating voltage from 2kV to 35kV) exposed to significant moisture and voltage are tested at least every ten years for an indication of the condition of the conductor insulation. The program inspects for water accumulation in manholes at least every two years.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Non-EQ Inaccessible Medium-Voltage Cable Program and basis documents to verify consistency with the GALL Report AMP XI.E3. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Non-EQ Inaccessible Medium-Voltage Cable Program elements (1) through (6) are consistent with the corresponding elements in the GALL Report AMP XI.E3. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

Operating Experience: In LRA Section B.1.23, the applicant states that the Non-EQ Inaccessible Medium-Voltage Cable Program is a new program. When implementing, the applicant will consider as its basis, industry operating experience in the operating experience element of the GALL Report program description. IP plant-specific operating experience is consistent with the operating experience in the GALL Report program description.

The applicant also stated that the IP program is based on the GALL Report program description, which in turn is based on industry operating experience. The applicant also stated that plant-specific operating experience is not inconsistent with that in the GALL Report. The applicant will consider industry and plant-specific operating experience when implementing the Non-EQ Inaccessible Medium-Voltage Cable Program to confirm the new program effectiveness. The applicant further stated that such operating experience assures program management of the effects of aging so components continue to perform intended functions consistent with the CLB through the period of extended operation.

SRP-LR Section A.1.2.3.10 provides guidance for staff review of operating experience. It states that an applicant may have to commit to providing operating experience in the future for new program to confirm their effectiveness. As stated above, the applicant stated that it will consider industry and plant-specific operating experience when implementing this program.

The NRC conducted its license renewal inspections in accordance with Inspection Procedure IP-71002 during the weeks of January 28th, February 11th, March 31st, and June 2nd of 2008. During the June 2008 inspection, the staff observed a scheduled quarterly preventive maintenance (PM) activity to open and inspect the IP3 manhole 36. The staff observed standing water with several cable splices submerged. These included two 6.9 kV cables, both associated with the station blackout/Appendix R diesel generator, and are within the scope of license renewal. The applicant pumped the water out of the manhole, and assessed the condition of the cable jackets and splices as acceptable. The staff reviewed the results of previous PM activities, and noted that water was typically found in the manhole at a depth sufficient to submerge at least the lower cable splices.

In GALL Report AMP XI.E3, under the detection of aging effects element, it recommends that the inspection for water collection should be performed based on actual plant experience with water accumulation in the manhole. However, the inspection frequency should be at least once every two years. The applicant currently performs quarterly PM activities to open the manholes and look for water accumulation. If water is found, as indicated by the applicant, the water is pumped out of the manhole. The applicant has considered and will continue to factor in plant operating experience when determining the frequency of inspection.

The staff has identified water in manholes as a generic, current operating plant issue in Information Notice 2002-12, "Submerged Safety-Related Electrical Cables," dated March 21, 2002, and in Generic Letter 2007-01, "Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients," dated February 7, 2007. The staff will address water in the manholes, for the current period of operation, through the reactor oversight process in accordance with the requirements of 10 CFR Part 50.

During review of the LRA, the staff determined that the Non-EQ Inaccessible Medium-Voltage Cable Program when implemented as described will ensure that the aging effects on inaccessible medium-voltage cables, due to exposure to significant moisture, will be adequately managed during the period of extended operation in accordance with the guidance in GALL Report, Section XI.E3. The Non-EQ Inaccessible Medium-Voltage Cable Program is a new program which recommends the applicant to test the cables and to evaluate plant-specific and industry-wide operating experience to determine if the inspection frequency of the manholes should be increased to ensure that the cables will be maintained in a dry environment during the period of extended operation.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

<u>UFSAR Supplement</u>. In LRA Sections A.2.1.22 and A.3.1.22, the applicant provided the UFSAR supplement for the Non-EQ Inaccessible Medium-Voltage Cable Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d). The applicant committed to implement the Non-EQ Inaccessible Medium-Voltage Cable Program prior to the period of extended operation. The applicant further stated that this new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.E3, "Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements" (Commitment 15).

By letter dated July 27, 2009, the applicant added a new commitment (Commitment 40) that states that plant specific and appropriate industry operating experience will be evaluated and lessons learned will be used to establish appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs.

<u>Conclusion</u>. On the basis of its audit and review of the applicant's Non-EQ Inaccessible Medium-Voltage Cable Program, the staff finds that all program elements are consistent with the GALL Report AMP XI.E3. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Non-EQ Instrumentation Circuits Test Review Program

<u>Summary of Technical Information in the Application:</u> LRA Section B.1.24 describes the Non-EQ Instrumentation Circuits Test Review Program as a new program that will be consistent with the GALL Report AMP XI.E2, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits."

The applicant stated that the Non-EQ Instrumentation Circuits Test Review Program is a new program that assures the intended functions of sensitive, high-voltage, low-signal cables exposed to adverse localized environments caused by heat, radiation, and moisture (i.e., neutron flux monitoring instrumentation) can be maintain consistent with the CLB through the period of extended operation. Most neutron flux monitoring system cables and connections are included in the instrumentation loop calibration at the normal calibration frequency, which provide sufficient indication of the need for corrective actions based on acceptance criteria related to instrumentation loop performance. The applicant further stated that for neutron monitoring system cables that are disconnected during instrumentation calibrations, testing using a proven method for detecting deterioration for the insulation system (such as insulation resistance tests or time domain reflectometry) will occur at least every ten years, with the first test occurring before the period of extended operation. Engineering evaluation will be performed when test acceptance criteria are not met and corrective actions, including modified inspection frequency, will be implemented to ensure that the intended functions of the cables can be maintained consistent with the CLB through the period of extended operation.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff reviewed the program elements of the Non-EQ Instrumentation Circuits Test Review Program and basis documents to verify consistency with the GALL Report AMP XI.E2. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Non-EQ Instrumentation Circuits Test Review Program elements (1) through (6) are consistent with the corresponding elements in the GALL Report AMP XI.E2 except for the following area. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

Under the program element 1 (scope of the program), the GALL Report AMP XI.E2 states that this program applies to high-range-radiation and neutron flux monitoring instrumentation cables in addition to other cables used in high voltage, low level signal applications that are sensitive to reduction in insulation resistance. In its Non-EQ Instrumentation Circuits Test Review Program, the applicant only included neutron monitoring system cables in the scope of the program. The staff requested the applicant to explain why high-range-radiation monitoring cables were not included in the program (Audit Item 64). The staff also requested the applicant to identify any other high voltage, low level signal cables and explain why these cables are not in scope under the Non-EQ Instrumentation Circuits Test Review Program. In a letter dated March 24, 2008, the applicant stated that although not explicitly listed, the high-range radiation monitoring cables were included in AMP B.1.24. The AMR included neutron monitoring circuits and high-range radiation monitoring circuits. The program description for AMP B.1.24 uses the phrase "(i.e., neutron monitoring instrumentation)." Since this was meant to be an example, the term "e.g." would have been a more appropriate choice than "i.e." The applicant also stated that:

> During the integrated plant assessment (IPA), the only high instrument voltage circuits with low signal values that were not subject to AMR were the incore detectors and the area radiation monitors. The nonsafety-related incore detectors and the area radiation monitors do not perform a license renewal intended function per 10 CFR 54.4(a)(1), (2), or (3). Therefore, the incore detectors and the area radiation monitors are not included in the scope of the B.1.24 (XI.E2) AMP.

A change will be made to LRA Section B.1.24 for clarification. The recommended change is as follows.

The Non-EQ Instrumentation Circuits Test Review Program is a new program that assures the intended functions of sensitive, high-voltage, low-signal cables exposed to adverse localized environments caused by heat, radiation and moisture (i.e., neutron flux monitoring instrumentation and high range radiation monitors); can be maintained consistent with the current license basis through the period of extended operation. Most sensitive instrumentation circuit cables and connections are included in the instrumentation loop calibration at the normal calibration frequency, which provide sufficient indication of the need for corrective actions based on acceptance criteria related to instrumentation loop performance. The review of calibration results will be performed once every ten years, with the first review occurring before the period of extended operation.

For sensitive instrumentation circuit cables that are disconnected during instrument calibration, testing using a proven method for detecting deterioration for the insulation system (such as insulation resistance tests or time domain reflectometry) will occur at least every ten years, with the first test occurs before the period of extended operation. In accordance with corrective action program, an engineering evaluation will be performed when test acceptance criteria are not met and corrective actions, including modified inspection frequency, will be implemented to ensure that the intended functions of the cables can be maintained consistent with the current licensing basis through the period of extended operation. This program will consider the technical information and guidance provided in NUREG/CR-5643, IEEE Std. P1205, SAND96-0344, and EPRI TR-109619.

The staff found the applicant's response acceptable because with the proposed LRA amendment and clarification described above, the scope of the Non-EQ Instrumentation Circuits Test Review Program is consistent with that in the GALL Report AMP XI.E2. The staff agreed with the applicant that incore detectors and area radiation monitors do not perform an intended function per 10 CFR 54.4(a)(1), (2), or (3) because they are non safety-related, their failure will not affect safety-function of safety-related components, and they are not credited in any regulated events under 10 CFR 54.4(a)(3). Therefore, they are not in the scope of the Non-EQ Instrumentation Circuits Test Review Program. The staff verified that in a letter dated December 18, 2007, the applicant amended LRA Section B.1.24 as described above.

Operating Experience. LRA Section B.1.24 states that the Non-EQ Instrumentation Circuits Test Review Program is a new program. When implementing this new program, the applicant will consider industry operating and plant-specific operating experience. Plant-specific operating experience is not inconsistent with the operating experience in the GALL Report program description.

The applicant also stated that the Non-EQ Instrumentation Circuits Test Review program is based on the GALL Report program description, which in turn is based on industry operating experience. The applicant further stated that such operating experience assures management of the effects of aging so components continue to perform their intended functions consistent with the CLB through the period of extended operation.

SRP-LR Section A.1.2.3.10 provides guidance for staff review of operating experience. It states that an applicant may have to commit to providing operating experience in the future for new program to confirm their effectiveness. As stated above, the applicant stated that it will consider industry and plant-specific operating experience when implementing this program.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.23 and A.3.1.23, the applicant provided the UFSAR supplement for the Non-EQ Instrumentation Circuits Test Review Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d). The applicant committed to implement the Non-EQ Instrumentation Circuits Test Review Program prior to the period of extended operation. The applicant further stated that this new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.E2, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits" (Commitment 16).

By letter dated July 27, 2009, the applicant added a new commitment (Commitment 40) that states that plant specific and appropriate industry operating experience will be evaluated and lessons learned will be used to establish appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs.

Conclusion. On the basis of its audit and review of the applicant's Non-EQ Instrumentation Circuits Test Review Program, the staff finds that all program elements are consistent with the GALL Report AMP XI.E2 program elements. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Non-EQ Insulated Cables and Connections Program

Summary of Technical Information in the Application. LRA Section B.1.25 describes the Non-EQ Insulated Cables and Connections Program as a new program that will be consistent with the GALL Report AMP XI.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

The applicant stated that the Non-EQ Insulated Cables and Connections Program assures maintenance of the intended functions of insulated cables and connections exposed to adverse environments of heat, radiation, and moisture consistent with the CLB through the period of extended operation. An adverse environment is significantly more severe than the specified service condition for the insulated cable or connection. The applicant further stated that a representative sample of accessible insulated cables and connections within the scope of license renewal will be inspected visually for cable and connection jacket surface anomalies (*e.g.*, embrittlement, discoloration, cracking or surface contamination). The technical basis for sampling will be determined from EPRI TR-109619, "Guideline for the Management of Adverse Localized Equipment Environments."

Staff Evaluation. During its audit and review, the staff reviewed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Non-EQ Insulated Cables and Connections Program and basis documents to verify consistency with the GALL Report AMP XI.E1. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Non-EQ Insulated Cables and Connections Program elements (1) through (6) are consistent with the corresponding elements in the GALL Report AMP XI.E1 except for the following area. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

Under the program description for this AMP, the GALL Report states that this program can be thought as a sampling program. Selected cables and connections from accessible areas (the inspection sample) are inspected and represent, with reasonable assurance, all cables and connection in the adverse localized environments. If an unacceptable condition or situation is identified for a cable or connection in the inspection sample, a determination is made as to whether the same condition or situation is applicable to other accessible or inaccessible cables or connections. In the program description of Non-EQ Insulated Cables and Connections Program, the applicant stated that a representative sample of accessible insulated cables and connections within the scope of license renewal will be visually inspected. The staff requested the applicant to describe the technical basis for sampling and action taken if degradation was found on a representative sample (Audit Item 65). In a letter dated March 24, 2008, the applicant stated that this program addresses cables and connections under the premise that a large portion of cables and connections are accessible. This program sample consists of all accessible cables and connections in localized adverse environments. If an unacceptable condition or situation for cable or connection during this visual inspection, the corrective action process will be used for resolution. As part of the corrective action process, a determination will be made as to whether the same condition or situation is applicable to other cables and connections. The applicant will revise the LRA Sections B.1.25, A.2.1.24, and A.3.1.24, second paragraph as described below:

> A representative sample of accessible insulated cables and connections within the scope of license renewal will be visually inspected for cable and connection jacket surface anomalies such as embrittlement, discoloration, cracking or surface contamination. The program sample consists of all accessible cables and connections in localized adverse environment.

The staff finds the applicant's response acceptable because the program will address cable and connections whose configuration is such that most (if not all) cables and connections installed in adverse localized environments are accessible. This program is a sampling program. Selected cables and connections from accessible areas (the inspection sample) are inspected and represent all cables and connections in the adverse localized environment. If an unacceptable condition or situation is identified for a cable or connection in the inspection sample, a determination is made to whether the same condition or situation is applicable to other cable or connections. The sample inspection is consistent with those in GALL AMP XI.E1. In a letter dated December 18, 2007, the applicant revised LRA Sections B.1.25, A.2.1.24, and A.3.1.24 as described above.

Operating Experience. LRA Section B.1.25 states that the Non-EQ Insulated Cables and Connections Program is a new program. When implementing this new program, the applicant will consider plant-specific and industrial operating experience as its basis. Plant-specific operating experience is not inconsistent with the operating experience in the GALL Report program description.

The applicant also stated that the Non-EQ Insulated Cables and Connections Program is based on the GALL Report program description, which in turn is based on industry operating experience. The applicant further stated that such operating experience assures management of the effects of aging so components continue to perform their intended functions consistent with the CLB through the period of extended operation.

SRP-LR Section A.1.2.3.10 provides guidance for staff review of operating experience. It states that an applicant may have to commit to providing operating experience in the future for new program to confirm their effectiveness. As stated above, the applicant stated that it will consider industry and plant-specific operating experience when implementing this program.

The staff confirmed that the “operating experience” program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.24 and A.3.1.24, the applicant provided the UFSAR supplement for the Non-EQ Insulated Cables and Connections Program. The staff reviewed these sections and the amendments as described above and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d). The applicant committed to implement the Non-EQ Insulated Cables and Connections Program prior to the period of extended operation. The applicant further stated that this new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.E1, “Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements” (Commitment 17).

By letter dated July 27, 2009, the applicant added a new commitment (Commitment 40) that states that plant specific and appropriate industry operating experience will be evaluated and lessons learned will be used to establish appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs.

Conclusion: On the basis of its audit and review of the applicant’s Non-EQ Insulated Cables and Connections Program, the staff finds all program elements consistent with the GALL Report program elements. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Program

Summary of Technical Information in the Application. LRA Section B.1.27 describes the One-Time Inspection Program as a new program that will be consistent with GALL AMP XI.M32, “One-Time Inspection.”

The One-Time Inspection Program confirms AMP effectiveness and the absence of aging effects. For structures and components that rely on AMPs, this program confirms that unacceptable degradation has not occurred and that component intended functions will be maintained during the period of extended operation. One-time inspections may be needed to address concerns about potentially long incubation periods for certain aging effects on structures and components. There are cases where either (a) an aging effect is not expected to occur but there is insufficient data to rule it out completely or (b) an aging effect is expected to progress very slowly. For these cases, there will be confirmation that either the aging effect indeed has not occurred or the aging effect occurs so slowly as not to affect the component's or structure's intended function. A one-time inspection of the subject component or structure is appropriate for this confirmation.

The elements of the program include (a) determination of the sample size based on an assessment of fabrication materials, environment, plausible aging effects, and operating experience, (b) determination of the system or component inspection locations for the aging effect, (c) determination of the examination technique, including acceptance criteria effective for managing the aging effect for which the component is examined; and (d) evaluation of the need for follow-up examinations to monitor the progression of any aging effect. The program will confirm the absence of aging effects as described:

A one-time inspection activity confirms the effectiveness of:

- water chemistry control programs by confirming that unacceptable cracking, loss of material, and fouling have not occurred on system components managed by the programs
- the Oil Analysis Program by confirming that unacceptable cracking, loss of material, and fouling have not occurred on system components managed by the program
- the Diesel Fuel Monitoring Program by confirming that unacceptable loss of material and fouling have not occurred on system components managed by the program

When a one-time inspection reveals evidence of an aging effect, routine evaluation of the inspection results develops appropriate corrective actions.

Staff Evaluation. During its audit and review, the staff reviewed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the One-Time Inspection Program and basis documents to verify consistency with the GALL Report AMP XI.M32. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the One-Time Inspection Program elements (1) through (6) are consistent with the corresponding elements in the GALL Report AMP XI.M32. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The applicant stated in the LRA that the sample size will provide 90 percent confidence that 90 percent of the population will not display degradation (90/90). The staff asked the applicant to justify the use of 90/90 for the sample size (Audit Item 71). By letter dated March 24, 2008, the applicant stated that it is following the guidelines in EPRI TR-107514, "Age Related Degradation Inspection Method and Demonstration," which describes methods used to inspect for age related degradation during the period of extended operation. This report recommends using the 90 percent confidence that 90 percent of the population will not display degradation. The justification for the 90/90 is that the locations selected for inspection are either the oldest components or are the locations most likely to be susceptible to degradation, so the true confidence is higher that 90 percent. The staff found this approach to be acceptable because biased sampling of the most susceptible locations should provide higher confidence than a 90/90 random sampling approach.

Operating Experience. LRA Section B.1.27 states that the One-Time Inspection Program is a new program. The applicant will consider industry operating experience when implementing this new program. The scopes of the inspections and inspection techniques are consistent with proven industry practices for managing the effects of aging. Plant-specific operating experience is consistent with the operating experience in the GALL Report program description.

The applicant also stated that the One-Time Inspection Program is based on the GALL Report program description, which in turn is based on industry operating experience. The applicant further stated that such operating experience assures management of the effects of aging so components continue to perform intended functions consistent with the CLB through the period of extended operation.

The staff confirmed that the “operating experience” program element satisfies the criterion defined in the GALL Report and in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.26 and A.3.1.26, the applicant provided the UFSAR supplement for the One-Time Inspection Program. By letter dated December 18, 2007, the applicant revised LRA Sections A.2.1.26, A.3.1.26, and B.1.27 to clarify that the "inspections will be nondestructive examinations (including visual, ultrasonic, or surface techniques)." Additionally, the applicant revised these sections for several one-time inspection activities that used the term "components" to replace the term "components" with the term "tanks, pump casings, piping, piping elements and components,” as appropriate. By letter dated June 12, 2009, the applicant revised LRA Section A.2.1.26 to add one-time inspection activities for the internal surfaces of stainless steel piping, tubing, strainers, and valve bodies in the IP1 station air system exposed to condensation. The staff reviewed these sections, as revised, and determines that the information in the UFSAR supplement, as clarified, is an adequate summary description of the program, as required by 10 CFR 54.21(d). The applicant stated in the LRA that this program will be implemented prior to the period of extended operation. In addition, the applicant stated that this new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M32, “One-Time Inspection” (Commitment 19).

By letter dated July 27, 2009, the applicant added a new commitment (Commitment 40) that states that plant specific and appropriate industry operating experience will be evaluated and lessons learned will be used to establish appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs.

Conclusion. On the basis of its audit and review of the applicant’s One-Time Inspection Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 One-Time Inspection - Small Bore Piping Program

Summary of Technical Information in the Application. LRA Section B.1.28 describes the One-Time Inspection - Small Bore Piping Program as a new program that will be consistent with GALL AMP XI.M35, “One-Time Inspection of ASME Code Class 1 Small-Bore Piping.”

LRA Section B.1.28 states that the One-Time Inspection - Small Bore Piping Program applies to small-bore ASME Code Class 1 piping less than 4 inches nominal pipe size (NPS), including pipe, fittings, and branch connections. The ASME Code does not require volumetric examination of Class 1 small-bore piping. The One-Time - Small Bore Piping Program will identify cracking by volumetric examinations.

The program will select a sample based on susceptibility, inspectability, dose considerations, operating experience, and limiting locations of the total population of ASME Code Class 1 small bore piping locations. When a one-time inspection reveals evidence of an aging effect, evaluation of the inspection results will develop appropriate corrective actions.

In the GALL Report program description, GALL AMP XI.M35 includes piping “less than or equal to NPS 4" with a reference to ASME Section XI, Table IWB-2500-1, Examination Category BJ; however, according to the ASME Code, a volumetric examination already is required for piping equal to 4-inch NPS. Consistent with the Code, GALL Report Item IV.C2-1 applies the One-Time Inspection of ASME Code Class 1 Small Bore Piping Program (XI.M35) only to Class 1 piping less than 4-inch NPS. On this basis, the applicant concludes that the intent of GALL Program XI.M35 is not to include 4-inc NPS pipe. Therefore, the One-Time Inspection - Small Bore Piping Program includes only small-bore Class 1 piping less than 4-inch NPS and as consistent with the GALL AMP.

Staff Evaluation. During its audit and review, the staff reviewed the applicant’s claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the One-Time Inspection – Small Bore Piping Program and basis documents to verify consistency with the GALL Report AMP XI.M35. Details of the staff’s audit of the applicant’s AMP are documented in the Audit Report. As documented in the report, the staff found that the One-Time Inspection – Small Bore Piping Program elements (1) through (6) are consistent with the corresponding elements in the GALL Report AMP XI.M35. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

During its review, the staff identified the following aspects of the applicant’s program that needed additional clarification: (1) whether inspections performed on ASME Code Class 1 small bore piping to date have indicated any indications of cracking in the components, (2) the basis that will be used for selecting ASME Code Class 1 small bore piping for inspection during the period of extended operation, (3) whether ASME Code Class 1 piping that is 4-inch in diameter NPS is within the scope of the program, and (4) the acceptance criteria that will be used to evaluate relevant indication of cracking in these components.

During an onsite audit, the staff asked the applicant if the applicant had experienced cracking of ASME Class 1 small bore piping as a result of stress corrosion cracking or thermal and mechanical loading (Audit Item 73). By letter dated December 18, 2007, the applicant clarified that inspections to date at IP 2 and IP 3 have not revealed any indications of cracking in the ASME Code Class 1 small-bore piping components for the units. Based on this review, the staff finds that the applicant has provided an acceptable basis for concluding that the One-Time Inspection - Small Bore Piping Program is an acceptable AMP to credit for managing cracking in the ASME Code Class 1 small bore piping because: (1) the AMP is an acceptable AMP to credit for cases where no indications of cracking have been detected in the ASME Code Class 1 small bore piping components and (2) the applicant has not detected any indications of cracking in its ASME Code Class 1 piping as a result of the inspections that have been performed on these components. The staff's concern on this matter is resolved.

During the audit the staff asked the applicant if they were going to follow the guidance in Materials Reliability Program (MRP) -24 for identifying susceptible locations for inspection (Audit Item 74). By letter dated December 18, 2007, the applicant clarified that the program elements for the One-Time Inspection – Small Bore Piping program will be consistent with the corresponding program element recommendations in GALL AMP XI.M35. The applicant clarified that the program will include a sample selected based on susceptibility, inspectability, dose considerations, operating experience, and limiting locations of the total population of ASME Code Class 1 small bore piping locations, and that MRP-24 (January 2001) or subsequent revisions of this industry guidance, will be followed for identifying susceptible locations for inspection. The staff noted that the applicant's response to Audit Item 74 was in conformance with the recommendation in the "monitoring and trending" program element in GALL AMP XI.M35, recommends that the sample size for the small bore piping inspections be based on a assessment of the susceptibility, inspectability, dose considerations, operating experience, and limiting locations of the total population of ASME Code Class 1 small-bore piping locations. The staff also noted that the applicant's response to Audit Item 74 was also in conformance with the recommendation in the "scope of program" program element in GALL AMP XI.M35 that EPRI Report 1000701, "Interim Thermal Fatigue Management Guideline (MRP-24)," January 2001 provides an acceptable basis for identifying those ASME Code Class 1 small bore piping locations that are most susceptible to cracking as a result of thermal stratification or turbulence.

Based on this review, the staff finds that the applicant has provided an acceptable basis for selecting those AMSE Code Class 1 small bore piping component for inspection because the applicant's basis is in conformance with the staff's recommendations for selecting susceptible components for inspection, as given in the "scope of program" program element in GALL AMP XI.M35. The staff also finds that the applicant has provided an acceptable basis for establishing the sample size of its AMSE Code Class 1 small bore piping component inspections because the applicant's basis is in conformance with the staff's recommendations for sample size, as given in the "monitoring and trending" program element in GALL AMP XI.M35. The staff's concern in Audit Item 74 is resolved.

During the audit, the staff asked the applicant if it intends to exclude 4" size from AMP B.1.28 from the scope of the applicant's One-Time Inspection - Small Bore Piping Program, and if so, whether this should be treated as an exception to GALL and a justification included in the LRA to establish exception to the GALL report (Audit Item 174). By letter dated December 18, 2007, the applicant clarified that the staff's AMR in GALL AMR Item IV.C2-1 identifies that the program is credited only for ASME Code Class 1 piping less than 4-inches NPS and that the Examination Categories B-F and B-J in Table IWB-2500-1 of the ASME Code, Section XI already require volumetric examinations for ASME Code Class 1 piping greater than or equal to 4-inches in diameter NPS. Thus, the applicant clarified that AMSE Code Class 1 piping equal to 4-inches NPS is not within the scope of the One-Time Inspection - Small Bore Piping Program. The staff verified that the requirements for volumetric examinations for ASME Code Class 1 piping greater than or equal to 4-inches in diameter NPS is already included within the scope of the applicant's Inservice Inspection Program (LRA AMP B.1.18). Based on this review, the staff finds that the applicant has provided an acceptable basis for excluding AMSE Code Class 1 piping equal to 4-inches NPS from the scope of the One-Time Inspection - Small Bore Piping Program because volumetric examinations of this ASME Code Class 1 pipe size is already included within the scope of the applicant's Inservice Inspection Program. The staff's concern in Audit Item 174 is resolved.

During the audit, the staff asked the applicant whether the applicant follows the applicable ASME Code, Section XI corrective action criteria in Paragraph IWB-3131 for flaw evaluation and supplemental examinations in Paragraph IWB-2430 for flaw indications exceeding their applicable flaw standard in Subarticle IWB-3400 (Audit Item 283). By letter dated December 18, 2007, the applicant confirmed that it follows the applicable ASME Code, Section XI corrective action criteria in Paragraph IWB-3131 for flaw evaluation and supplemental examinations in Paragraph IWB-2430 for any flaw indication in a small bore Class 1 piping components that exceeds its applicable flaw standard in Subarticle IWB-3400. The staff noted that the volumetric examinations recommended in GALL AMP XI.M35 for small bore Class 1 piping components are not ASME Code, Section XI mandated examinations, and therefore, go beyond the current 10 CFR 50.55a mandated inservice inspection (ISI) requirements for these types of components in ASME Code, Section XI Table IWB-2500-1. As such, the applicant is not obligated to using the stated ASME Code, Section XI-based correction actions for its non-mandatory, LRA-recommended one-time volumetric examinations. The staff noted, however, that the applicant credited these ASME Code, Section XI-based corrective action provisions for any flaw indication in a small bore Class 1 piping components that exceeds its applicable flaw standard in Subarticle IWB-3400. Thus, the staff finds that the applicant has provided an acceptable basis for corrective actions of any non-conforming indications because the applicant is applying the conservative Code-based corrective actions to any non-conforming indication that is detected as a result of the non-mandatory, LRA-recommended one-time volumetric examinations that will be performed on these small bore ASME Code Class 1 piping components. The staff's concern in Audit Item 283 is resolved.

Based on the review of this AMP and the applicant's responses to the audit questions, the staff finds this program acceptable because the staff has verified that the program elements for the applicant's One-Time Inspection – Small Bore Piping Program are in conformance with the staff's aging management criteria that are provided in the program elements of GALL AMP XI.M35, and because the applicant will implement this program consistent with GALL AMP XI.M35 recommendations.

<u>Operating Experience</u>. LRA Section B.1.28 states that the One-Time Inspection - Small Bore Piping Program is a new program. When implementing this new program the applicant will consider as its basis industry operating experience in the GALL Report program description, which in turn is based on industry operating experience. Such operating experience assures program management of the effects of aging so components continue to perform intended functions consistent with the CLB through the period of extended operation.

In its response to Audit Item 73, the applicant indicated that previous non-volumetric inservice inspections performed on the small bore ASME Code Class 1 piping components did not reveal any indication of cracking in the piping components. In addition, the staff noted that the applicant indicated that there are not any small bore ASME Code Class 1 socket welds at IP2 and IP3 that have been identified as critical welds from a risk-informed inservice inspection (RI–ISI) program perspective. Therefore, small bore ASME Code Class 1 socket welds are not included within the scope of the applicant's One-Time Inspection - Small Bore Piping Program. The staff has confirmed that the applicant instead credits the surface examination requirements and visual examination requirements in the applicant's Inservice Inspection Program as the basis for inspecting the applicant's small bore ASME Code Class 1 socket welds. Based on this review, the staff finds that the applicant has provided an acceptable basis for concluding that the One-Time Inspection - Small Bore Piping Program may be used to verify whether cracking is occurring in the applicant's ASME Code Class 1 piping components during the period of extended operation because the applicant has not detected any indications of cracking as a result of the non-volumetric examinations that were performed on these components through implementation of the applicant's Inservice Inspection Program, and because the IP2 and IP3 designs do not include any critical small bore ASME Code Class 1 socket weld locations that are considered to be critical risk-informed locations under the applicant's RI-ISI program. Based on this review, the staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.27 and A.3.1.27, the applicant provided the UFSAR supplement for the One-Time Inspection - Small Bore Piping Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d). The applicant stated in the LRA that this program will be implemented prior to the period of extended operation. In addition, the applicant stated that this new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M35, "One-Time Inspection – Small Bore Piping" (Commitment 20).

By letter dated July 27, 2009, the applicant added a new commitment (Commitment 40) that states that plant specific and appropriate industry operating experience will be evaluated and lessons learned will be used to establish appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs.

Conclusion. On the basis of its audit and review of the applicant's One-Time Inspection - Small Bore Piping Program, the staff finds that all program elements are consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Reactor Head Closure Studs Program

Summary of Technical Information in the Application. LRA Section B.1.30 describes the existing Reactor Head Closure Studs Program as consistent with GALL AMP XI.M3, "Reactor Head Closure Studs."

The Reactor Head Closure Studs Program includes inservice inspection (ISI) in compliance with the requirements of ASME Section XI, Subsection IWB, and preventive measures (e.g., rust inhibitors, stable lubricants, appropriate materials) to mitigate cracking and loss of material of reactor head closure studs, nuts, washers, and bushings.

The GALL Report program, Section XI.M3, Reactor Head Closure Studs, is based on ASME Code 2001 Edition including the 2002 and 2003 Addenda. The ISI program is based on ASME Code 1989 Edition, no addenda, with inspection of reactor head closure studs based on the 1998 Edition through the 2000 Addenda. The 1998 Edition through the 2000 Addenda allow surface or volumetric examination when closure studs are removed. This is consistent with the requirements of GALL Report, Section XI.M3. Therefore, use of different ASME Code editions for this program is not an exception to the GALL Report.

Staff Evaluation. During its audit and review, the staff reviewed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Reactor Head Closure Studs Program and basis documents to verify consistency with the GALL Report AMP XI.M3. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Reactor Head Closure Studs Program elements (1) through (6) are consistent with the corresponding elements in the GALL Report AMP XI.M3. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff confirmed that the existing Reactor Head Closure Studs Program at IP is part of the applicant's ISI program under ASME Code, Section XI, Subsection IWB, Examination Category B-G-1. The staff also confirmed that the program includes the preventive measures (e.g., rust inhibitors, stable lubricants, appropriate materials) that are recommended in NRC RG 1.65 to mitigate cracking and loss of material of reactor head closure studs, nuts, washers, and bushings, and that these activities are performed under several plant-specific programs or activities. The staff verified that these programs and activities include measures to ensure conformance with closure stud material specifications during procurement, metal plating activities to prevent corrosion or hydrogen embrittlement, use of manganese phosphate or other acceptable surface treatment and stable lubricant during service, and implementation of the ISI examinations, which mandated by the ASME Code, Section XI, Examination B-G-1 requirements. The staff found this to be acceptable because it is in compliance with the requirements for reactor vessel closure stud components in the ASME Code, Section XI and because it is in conformance with the program element recommendations in GALL AMP XI.M3.

The staff notes that this program is based on the ASME Section XI Code Edition 1998, up to 2000 addenda, although the applicant's Inservice Inspection Program is based on 1989 Edition of the Code. According to the 1998 Code Edition (Code Item B6.30), the program allows surface or volumetric examination when closure studs are removed, which is not consistent with the requirements of GALL Report, Section XI.M3. The GALL Report program element "detection of aging effects" states that the Code requires "both surface and volumetric examination of studs" when removed. During an onsite audit, the staff asked Entergy to clarify why this is not an exception to the GALL recommendations (Audit Item 82).

By letter dated March 24, 2008, the applicant stated that GALL AMP XI.M3 also references ASME Section XI 2001 edition including the 2002 and 2003 Addenda, which allows surface or volumetric examination when closure studs are removed. The applicant also clarified that the inservice inspection requirements in the 1998 Edition of the ASME Code, Section XI, inclusive of the 2000 Addenda require either a surface examination or volumetric examination of the closure studs when they are removed. This is the same examination requirement for these studs that is provided in the 2001 Edition of ASME Code, Section XI, inclusive of the 2003 Addenda referenced in GALL AMP XI.M3. The staff reviewed the two Code editions and verified that the examination requirements for reactor vessel closure studs in the 1998 Edition of the

ASME Code, Section XI (inclusive of the 2000 Addenda) is the same as that required for the studs in the 2001 Edition of the ASME Code, Section XI (inclusive of the 2003 Addenda). The staff also noted that, in the applicant's letter of June 11, 2008, the applicant clarified that the updated Code of Record for IP2 is the 2001 Edition of the ASME Code, Section XI, inclusive of the 2003 Addenda, and that the Code of Record for IP3 is the 1989 Edition of the ASME Code, Section XI. The staff verified that the use of the 2001 Edition of the ASME Code, Section XI, inclusive of the 2003 Addenda is consistent with the Code editions referenced for use in GALL AMP XI.M3. The staff also confirmed that the inservice inspection bases for the reactor vessel closure studs in the 1998 Edition of the ASME Code, Section XI, inclusive of the 2000 Addenda, are the same as, and are consistent with, the inservice inspection bases for the closure studs in the 2001 Edition of the ASME Code, inclusive of the 2003 Addenda, as referenced for use in GALL AMP XI.M3. Therefore, based on this review the staff finds that the inspection bases for the reactor vessel closure studs at IP2 and IP3 are consistent with the Code requirements referenced in GALL AMP XI.M3 and are acceptable.

During an onsite audit, the staff reviewed the following four aspects of the RG 1.65 recommendations: material specification during procurement, avoiding the use of metal-plated stud bolting to prevent corrosion or hydrogen embrittlement, use of manganese phosphate or other acceptable surface treatments and stable lubricants during service, and ISI examination. During the audit, Entergy provided access to plant documents that addressed the RG 1.65 recommendations. The staff determined that the procurement and material specifications aspects of the RG 1.65 recommendations are followed as evidenced in purchase order documents. The staff determined that the preventive measures recommended in the RG with respect to lubricants, rust inhibitors, etc., are not applicable to IP since all bolts are plasma bonded and since this fabrication method does not involve the use of lubricants. The staff noted that the applicant implements the inspections of its reactor vessel closure studs in accordance with the applicant's Inservice Inspection Program (refer to AMP B.1.18) and the ASME Code, Section XI Examination Category B-G-1 requirements for reactor vessel closure assembly components. The staff finds this to be acceptable because it is in compliance with the requirements of 10 CFR 50.55a and the ASME Code, Section XI and because it is in conformance with the inspection recommendations for reactor vessel closure studs in GALL AMP XI.M3.

The staff also notes that this AMP, as recommended in RG 1.65, is applicable to closure studs and nuts constructed from materials with a maximum tensile strength limited to less than 170 ksi (1,170 MPa). During discussions with the applicant during the audit, Entergy stated that, for IP2, results of testing from available test reports for the original and refurbished reactor head closure stud and nut material showed a maximum tensile strength value < 170 ksi (1,170 MPa). However, for IP3, the original and refurbished reactor head closure stud and nut materials showed a maximum tensile strength value of 174 ksi (1,200 MPa), which was above the value in RG 1.65. The applicant also stated that the slight deviation above 170 ksi (1,170 MPa) shown in the test results does not significantly increase the material's potential for embrittlement and stress corrosion cracking. After reviewing the tensile testing data on bolt materials for IP3, the staff determined that the test results relating to several tests both for original and replaced studs are made out of ASME SA-540 B23/24 materials with an average tensile strength less than 170 ksi (1,170 MPa). The staff determined that, for IP3, only a few of the test results for the original bolt materials exceeded the 170 ksi (1,170 MPa) limit, with a maximum of 174 ksi (1,200 MPa). The staff verified that, in order to address the issue with high tensile strength RV studs, the applicant has appropriately identified cracking as an applicable aging effect requiring management for the IP2 and IP3 reactor vessel closure assembly studs, nuts and washers, and that the applicant credits the inservice inspections that are within the scope of this AMP and are implemented in accordance with the applicant's Inservice Inspection Program, Examination Category B-G-1 requirements as the basis for managing cracking in these components. The staff finds this to be acceptable because it is in accordance with the "parameters monitored or inspected" and "detection of aging effects" program elements in GALL AMP XI.M3.

Since the program basis documents for the Reactor Head Closure Studs Program is based on the ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 requirements and the recommendations in NRC RG 1.65, the staff finds that the applicant's Reactor Vessel Closure Studs Program is consistent with recommended program element criteria in GALL AMP XI.M3 and is acceptable.

Operating Experience. LRA Section B.1.30 states that ISI-IWB examinations were conducted at IP2 and IP3 during 2004 and 2005. Results found to be outside of acceptable limits were repaired, replaced, or evaluated in accordance with ASME Section XI requirements. Detection of degradation and corrective action prior to loss of intended function assure program effectiveness in managing aging effects.

The applicant also stated that an ISI program self-assessment was completed in October 2004. Review of the scope for refueling outage 2R16 (2004) and refueling outage 3R13 (2005) verified that the proper inspection percentages had been planned for both outages. A follow-up assessment for IP2 in March 2006 ensured that all inspection activities required to close out the third 10-year ISI interval were scheduled for refueling outage 2R17. The applicant concluded that confirmation of compliance with program requirements assures continued effective management of loss of component material. QA surveillances in 2005 and 2006 revealed no issues or findings that could impact program effectiveness.

The staff reviewed the QA self-assessment documents for the applicant's Inservice Inspection Program for IP2 and IP3 and found that QA self-assessments reported that the applicant's Inservice Inspection Program appropriately identified and took corrective measures on the inspection findings. The staff noted that there are several deficiencies identified in these reports and verified that the applicant has taken appropriate corrective actions to address the deficiencies that were identified in these reports. Based on this aspect of the applicant's program, the staff did not identify any issues with the applicant's program that would impact the effectiveness of the Reactor Head Closure Studs Program in managing the aging effects that are applicable to the RV closure stud assembly components.

Therefore, based on this review, the staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.29 and A.3.1.29, the applicant provided the UFSAR supplement for the Reactor Head Closure Studs Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Reactor Head Closure Studs Program, the staff finds that all program elements are consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Reactor Vessel Head Penetration Inspection Program

Summary of Technical Information in the Application. LRA Section B.1.31 describes the existing Reactor Vessel Head Penetration Inspection Program as consistent with GALL AMP XI.M11A, "Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors."

LRA Section B.1.31 states that the Reactor Vessel Head Penetration Inspection Program manages primary water stress corrosion cracking (PWSCC) of nickel-based alloy reactor vessel head penetrations exposed to borated water to maintain pressure boundary function. This program was developed in response to NRC Order EA-03-009. The applicant uses the ASME Section XI, Subsection IWB Inservice Inspection and Water Chemistry Control Programs with this program to manage cracking of the reactor vessel head penetrations. A combination of bare metal visual examination (external surface of head) and non-visual examination (underside of head) techniques detects cracking. Procedures are developed for reactor vessel head bare metal inspections and calculations of plant susceptibility ranking. Entergy will continue to implement commitments to (1) NRC orders, bulletins, and GLs on nickel alloys and (2) staff-accepted industry guidelines.

Staff Evaluation. During its audit and review, the staff reviewed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Reactor Vessel Head Penetration Inspection Program and basis documents to verify consistency with the GALL Report AMP XI.M11A. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Reactor Vessel Head Penetration Inspection Program elements (1) through (6) are consistent with the corresponding elements in the GALL Report AMP XI.M11A. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

During audit, the staff confirmed that all 97 penetrations at IP2 and all 78 penetrations at IP3 reactor vessel heads and associated J-groove welds, and the adjoining upper RV closure heads are within the scope of this program.

The staff noted that this program was developed based on the commitments that the applicant made in response to the staff's augmented inspection and flaw evaluation requirements that were issued in NRC Order EA-03-009, as amended in the applicant's response to the staff's augmented inspection and flaw evaluation requirements that were issued in First Revised Order EA-03-009 (henceforth referred to the Order as Amended). The staff verified the applicant's commitments made in the applicant's responses to the Order as Amended are within the scope of the program, as provided in the following Entergy Letters:

- Entergy Letter No. NL-03-037, dated March 3, 2003 (ADAMS Accession number ML030650884)
- Entergy Letter No. NL-04-026, dated March 11, 2004 (ADAMS Accession number ML041610278)

The staff noted that the applicant credits its Water Chemistry Control Program – Primary and Secondary in conjunction with this program to manage cracking of the reactor vessel head penetration nozzles and their associated nickel alloy nozzle-to-vessel penetration welds. The staff finds this to be acceptable because it is consistent with the AMRs that invoke this program for aging management, and because this in accordance with the "preventive actions" program element criteria that are recommended in GALL Report AMP XI.M11A.

The staff noted that the program uses a combination of bare metal visual examination (external surface of head) and non-visual examination (underside of head) techniques as the bases for managing cracking that is postulated to occur in these nozzle components. The staff finds this to be acceptable because it is in conformance with the "detection of aging effects" program element in GALL Report AMP XI.M11-A.

The staff noted and verified that the applicant has established plant procedures that govern the applicant's augmented bare metal visual inservice inspection activities for the IP2 and IP3 upper reactor vessel RV closure heads and the non-visual non-destructive examination (non-visual NDE) methods (i.e., either ultrasonic testing (UT) or eddy current testing (ECT)) for the nickel alloy upper RV closure head penetration nozzles and their associated nickel alloy penetration welds. The staff also noted that the applicant has established plant procedures for calculating the susceptibility rankings of the IP2 and IP3 upper RV closure head penetration nozzles in accordance with susceptibility ranking calculation requirements of the Order as Amended.

By letter dated March 24, 2008, in response to an audit question (Audit Item 83), the applicant clarified that, as of the last refueling outage for IP2 (Spring 2006), the upper RV closure head penetration nozzles at IP2 are categorized as a moderate susceptibility category penetration nozzles, as calculated using the staff's required susceptibility calculation equations that are given in the Order as Amended, and as of the last refueling outage for IP3 (Spring 2007), the upper RV closure head penetration nozzles at IP3 are categorized as a high susceptibility category penetration nozzles, as calculated using the same required susceptibility calculation equations. The staff finds this to be acceptable because it is in compliance with the requirements in the Order as amended, and because this is consistent with the "detection of aging effects" and "monitoring and trending" program elements in GALL Report AMP XI.M11A.

The staff verified that the applicant has established an augmented inspection program plan for these Class 1 penetration nozzles that addresses all of the bare metal visual and non-visual NDE inspection requirements in the Order as amended for the upper RV closure head penetrations, as ranked for the moderate susceptibility ranking for IP2 and the high susceptibility ranking for IP3, and approved for relaxation from the requirements of the Order as Amended in the following NRC safety evaluations:

- Safety evaluation for IP2 dated February 27, 2006, granting a reduced vertical inspection coverage for the RV closure head penetration nozzles based on the inaccessibility of the threaded non-pressure boundary portions of the nozzles
- Safety evaluation for IP2 dated October 15, 2004, granting a reduced inspection coverage (to 95% coverage) for bare metal examinations required to be performed on the IP2 upper RV closure head
- Safety evaluation for IP3 dated April 4, 2005, granting a reduced vertical inspection coverage for the RV closure head penetration nozzles based on the inaccessibility of the threaded non-pressure boundary portions of the nozzles

- Safety evaluation for IP3 dated March 18, 2005, granting a reduced inspection coverage (to 95% coverage) for bare metal examinations required to be performed on the IP3 upper RV closure head

The staff finds that the inspection bases granted in these safety evaluations are acceptable because they are in conformance with the required inspection bases that are defined in the "detection of aging effects" and "monitoring and trending" program elements in GALL Report AMP XI.M11A.

In the same response (Audit Item 83), Entergy also stated that the Boric Acid Corrosion Prevention Program (B.1.5) complements the Reactor Vessel Head Penetration Inspection Program by performing visual inspection of the reactor vessel head at locations specified by IP2-specific and IP3-specific plant procedures. The staff noted that these procedures provide general guidance for performing the system walkdowns and bare metal visual examinations of both the IP2 and IP3 upper RV closure heads and other ASME Code Class 1 components for evidence of boric acid leakage, boric acid residues, or signs of corrosion.

The staff verified that the applicant coordinates the activities with reactor vessel disassembly and the inspections that are required by Order as Amended, in accordance with the applicant's implementing procedures and outage scheduling.

Based on its review of the applicant's augmented inspection program plan for upper RV closure heads and its associated penetrations nozzles, the staff verified that the applicant credits the program's UT and ECT examination methods for the detection of cracking of nozzle penetrations and their nickel alloy penetration welds. The staff also verified that the applicant credits its bare metal visual inspections of the upper RV heads with the detection of evidence of reactor coolant leakage from the upper RV closure head penetration nozzles, boric acid residues that precipitate out on the upper RV head or adjacent components, or corrosion products that result from rusting of the low-alloy steel materials used to fabricate the RV heads or shells. The staff finds that this is acceptable because the inspection methods that are credited for examination and the parameters that these inspections methods are credited for are consistent with the staff's recommended criteria that are provided in the "parameters monitored/inspected" and "detection of aging effects" program elements in GALL Report AMP XI.M11A.

Based on this review, the staff finds that the applicant Reactor Vessel Head Penetration Inspection Program is acceptable because the program is designed to be in compliance with the requirements of the Order as Amended and because the staff has verified that the program elements for the program are in conformance with the program element criteria that are recommended in GALL Report AMP XI.M11A.

Operating Experience. LRA Section B.1.31 states that bare metal visual examination of no less than 95 percent of the IP2 reactor vessel head surface and 360 degrees around each head penetration nozzle completed in November 2004 (refueling outage 2R16) consistently with the requirements of NRC Order EA-03-009 and approved relaxation request found no indications of reactor vessel head degradation or leakage due to cracking.

The applicant also stated that bare metal visual examination of no less than 95 percent of the IP3 reactor vessel head surface and 360 degrees around each head penetration nozzle completed during March 2005 (refueling outage 3R13), consistent with the requirements of NRC

Order EA-03-009 and approved relaxation requests, found no indications of reactor vessel head degradation or leakage due to cracking. A QA surveillance of these inspections found all regulatory requirements met.

Further, the applicant stated that the most recent inspection of the IP2 reactor vessel head penetrations completed in May 2006 (refueling outage 2R17) used a procedure written from lessons learned during the refueling outage 2R16 and refueling outage 3R13 inspections. The results of this refueling outage 2R17 inspection were satisfactory. This inspection noted that bare metal areas reviewed had significant improvement in the cleanliness in the base metal and annulus around the penetrations. A QA surveillance of these inspections found all regulatory requirements met. A self-assessment of the inspection process noted improvements that should be made before future use of the process. Corrective actions implemented these process improvements. Absence of cracking with continuous improvement of material condition assures program effectiveness in managing aging effects. Use of recent operating experience and industry guidance in the development of site-wide procedures with site QA oversight and continuous process improvement assures continued program effectiveness in managing aging effects for passive components.

The staff verified that the applicant's Reactor Vessel Head Penetration Inspection Program was developed and is being implemented to address the cracking and boric acid leakage events that have been identified and discussed in the Order as Amended, and in NRC Bulletins 2002-01 and 2002-02, that were issued prior to the Order as Amended.

The staff verified that the latest augmented inspection reports for the IP2 and IP3 upper RV closure head and its penetration nozzles are given in the following inspection reports that were required to be reported in accordance with the requirements of the Order as Amended:

- Entergy Letter No. NL-05-001 for IP2, dated January 17, 2005 (ML050340067) – reporting bare metal visual examination inspection results performed on the IP2 head.
- Entergy Letter No. NL-06-064 for IP2, dated July 12, 2006 (ML062140076) – reporting non-visual NDE inspections on all 97 upper RV closure head penetration nozzles using UT and ECT.
- Entergy Letter No. NL-05-044 for IP3, dated May 31, 2005 (ML051590104) – reporting bare metal visual examination inspection results performed on the IP3 head.
- Entergy Letter No. NL-06-064 for IP3, dated July 12, 2006 (ML062140076) – reporting non-visual NDE inspections on all 97 upper RV closure head penetration nozzles using both UT and ECT).

The staff verified that in the letters, Entergy reported that the inspections did not identify any indications of reactor coolant pressure boundary leakage from the IP2 and IP3 upper RV closure head penetration nozzles or evidence of cracking in these nozzles or their structural nickel-alloy welds. By letter dated January 17, 2005, the applicant did report some Conoseal leakage at IP2 and IP3. The staff's evaluation on the applicant's steps to correct Conoseal leakage is given in SER Section 3.0.3.1.1. Based on this review, the staff also finds that the applicant has been taking appropriate steps to determine whether there is any site-specific operating experience on cracking of the IP2 and IP3 upper RV closure head penetration nozzles or on reactor coolant leakage from the nozzles onto the upper RV closure head or adjacent Class 1 components.

Based on this review, the staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10 because the staff has verified that applicant is currently performing the mandatory examinations of the IP2 and IP3 upper RV closure heads and their penetration nozzles in order to address the generic operating experience discussed in the Order as Amended. Based on this review, the staff finds this program element to be acceptable.

UFSAR Supplement. In LRA Sections A.2.1.30 and A.3.1.30, the applicant provided the UFSAR supplement for the Reactor Vessel Head Penetration Inspection Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Reactor Vessel Head Penetration Inspection Program, the staff finds that all program elements are consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Selective Leaching Program

Summary of Technical Information in the Application. LRA Section B.1.33 describes the Selective Leaching Program as a new program that will be consistent with GALL AMP XI.M33, "Selective Leaching of Materials."

In the LRA, the applicant stated that the Selective Leaching Program will ensure the integrity of components made of gray cast iron, bronze, brass, and other alloys exposed to raw water, treated water, or groundwater that may lead to selective leaching. The program will include a one-time visual inspection, hardness measurement (where feasible based on form and configuration) or other industry-accepted mechanical inspection techniques of selected components that may be susceptible to selective leaching to determine whether loss of material due to selective leaching has occurred and whether the process will affect component ability to perform intended functions through the period of extended operation.

By letter dated March 24, 2008, the applicant amended the program description to add the following:

> The selected set or representative sample size will be based on Chapter 4 of EPRI document 107514, Age Related Degradation Inspection Method and Demonstration, which outlines a method to determine the number of inspections required for 90% confidence that 90% of the population does not experience degradation (90/90). Each group of components with the same material-environment combination is considered a separate population.

Staff Evaluation. During its audit and review, the staff reviewed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Selective Leaching Program to verify consistency with GALL AMP XI.M33. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Selective Leaching Program elements (1) through (6) are consistent with the corresponding elements in GALL AMP XI.M33. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

During the audit, the staff reviewed the applicant's program evaluation document and confirmed that the program scope includes all systems that could be susceptible to selective leaching. These include cast iron, brass, bronze, or aluminum-bronze and exposed to raw water, treated water, or groundwater environments. Systems that have this combination of material and environment include susceptible components that include piping, valve bodies and bonnets, pump casings, and heat exchanger (HX) components.

Operating Experience. LRA Section B.1.33 states that the Selective Leaching Program is a new program. When implementing this new program, the applicant will consider as its basis industry operating experience in the operating experience element of the GALL Report program description. Plant-specific operating experience is not inconsistent with the operating experience in the GALL Report program description.

The program is based on the GALL Report program description, which in turn is based on industry operating experience. Such operating experience assures program management of aging effects so components continue to perform intended functions consistent with the CLB through the period of extend operation.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.32 and A.3.1.32, the applicant provided the UFSAR supplement for the Selective Leaching Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d). The applicant stated in the LRA that this program will be implemented prior to the period of extended operation. In addition, the applicant stated that this new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M33, "Selective Leaching of Materials" (Commitment 23).

By letter dated July 27, 2009, the applicant added a new commitment (Commitment 40) that states that plant specific and appropriate industry operating experience will be evaluated and lessons learned will be used to establish appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs.

Conclusion. On the basis of its audit and review of the applicant's Selective Leaching Program, the staff finds that all program elements are consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Service Water Integrity Program

Summary of Technical Information in the Application. LRA Section B.1.34 describes the existing Service Water Integrity Program as consistent with GALL AMP XI.M20, "Open-Cycle Cooling Water System."

The Service Water Integrity Program implements the recommendations of GL 89-13 for managing the effects of aging on the service water (SW) system, through the period of extended operation. The program inspects components for erosion, corrosion, and biofouling to confirm the heat transfer capability of safety-related heat exchangers cooled by SW. Chemical treatment with biocides and sodium hypochlorite and periodic cleaning and flushing of loops infrequently used are methods for controlling fouling within the heat exchangers and managing loss of material in SW components.

Staff Evaluation. During its audit and review, the staff reviewed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff reviewed the program elements of the Service Water Integrity Program to verify consistency with GALL AMP XI.M20. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Service Water Integrity Program elements (1) through (6) are consistent with the corresponding elements in GALL AMP XI.M20. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

Operating Experience. LRA Section B.1.34 states that in July 2003 a peer assessment of the IP3 SW program conducted by EPRI found some areas for improvement. Corrective actions included changes to chlorination practices and evaluation of new software tools for heat exchanger performance analysis. Assessment of practices by offsite review groups and appropriate corrective action assure continued program effectiveness in managing aging effects for passive components.

The applicant stated that self-assessments of the IP2 and IP3 ultimate heat sink (GL 89-13 Program) in April 2004 and June 2005 focused on adequate maintenance of ultimate heat sink subcomponents and their operation within the plant design basis. The applicant concluded that detection of program weaknesses and subsequent corrective actions assure continued program effectiveness in managing loss of component material.

In the LRA, the applicant noted that in December 2005, the staff completed an ultimate heat sink performance review at IP2 to verify that Entergy continually monitored performance of the instrument air closed cooling water heat exchangers and to detect potential deficiencies which could mask degraded performance. The staff reviewed the design basis documents and final safety analysis report for whether testing acceptance criteria were appropriate. The staff also reviewed the latest inspection reports for the heat exchangers and evaluated the results of eddy current testing for use of appropriate tube plugging criteria. In addition, the staff verified whether Entergy had maintained its commitments to GL 89-13 on heat exchanger inspection and testing and made no findings. Confirmation of program compliance with established standards and regulations assures continued program effectiveness in managing loss of component material.

As part of the ultimate heat sink performance review at IP3 in 2005, the staff observed the condition of a component cooling water (CCW) heat exchanger after it had been opened for periodic inspection and cleaning and reviewed preventive maintenance of this safety-related heat exchanger for adequacy in minimizing the effects of biofouling on its performance. The staff visually examined the heat exchanger when it was first opened to assess the adequacy of Entergy's periodic cleaning to avoid excessive fouling, compared the as-found eddy current testing results to previous testing data, and made no significant findings. Reviews of program specifics prove program effectiveness in managing loss of component material.

The applicant also noted that in June 2006, the staff completed an ultimate heat sink performance review at IP3 for whether Entergy had used the periodic maintenance method outlined in EPRI NP-7552, "Heat Exchanger Performance Monitoring Guidelines," for the IP3 emergency diesel generator (EDG) lube oil coolers. The staff reviewed the results of the last inspections and eddy current tests for each of the lube oil coolers and made no significant findings. Confirmation of program compliance with established standards and regulations assures continued program effectiveness in managing loss of component material.

Further, the applicant stated, in June 2006, the staff completed at IP2 an ultimate heat sink performance review which included the CCW heat exchangers and the EDG jacket water and lube oil heat exchangers. The staff reviewed documents for whether Entergy had detected and corrected common cause heat sink performance problems with the potential to increase risk. The staff also reviewed records for whether Entergy had examined potential macro fouling (silt, debris, etc.) and biofouling issues closely. To ensure adequate implementation of Generic Letter 89-13, the staff reviewed Entergy's inspection, cleaning, and eddy current testing methods and frequency with the responsible system engineers. The staff compared surveillance test and inspection data, including as-found conditions and eddy current summary sheets, to the established acceptance criteria to verify whether the results were acceptable and the system heat exchanger operation was consistent with design. The staff reviewed heat exchanger design-basis values and assumptions, plugging limit calculations, and vendor information to verify whether they were incorporated into the heat exchanger inspection and maintenance procedures. The staff reviewed a sample of condition reports for the CCW and EDG heat exchangers and the SWS for whether Entergy had detected, characterized, and corrected problems related to these systems and components appropriately and made no significant findings. Confirmation of program compliance with established standards and regulations assures continued program effectiveness in managing loss of component material.

The staff's review of Appendix B of the LRA and of the applicant's basis document found them to conclude that the Service Water Integrity Program has been effective in managing those aging effects for which it is credited. The staff noted, however, that this conclusion is based on the results of one peer assessment, one self-assessment and five NRC inspections of the GL 89-13 program. Since the guidelines of GL 89-13 are directed at ensuring the performance of safety-related systems and components exposed to SW, it is not clear how the results of inspections performed under the GL 89-13 program could be used to confirm the absence of aging effects in nonsafety-related components within scope for license renewal. In addition, NRC inspections of the GL 89-13 program are based on a limited sample of safety-related components. For example, NRC Inspection Procedure IP 93810 (Service Water System Operational Performance Inspection) specifically states that the selection of SW system components and systems should consider those that have been dominant contributors to the SW system operational risk at the plant or similar plants.

In RAI AUX-2, dated May 7, 2008, the staff requested the applicant to clarify whether the Service Water Integrity Program is credited for aging management of the nonsafety-related components of the SW system that are within scope for license renewal, and if so, to provide evidence for the conclusion presented in the LRA, that this AMP is effective in managing age-related degradation. If this AMP is not credited, the staff requested the applicant to identify the AMP(s) that are credited for aging management of the nonsafety-related components of the SW system that are within scope for license renewal and to provide the basis for concluding that these programs have been or will be effective for managing aging during the license renewal period.

By letter dated June 5, 2008, the applicant provided the following response:

> The Service Water Integrity Program is credited for managing the effects of aging on components as listed in LRA Section 3 tables regardless of safety classification.
>
> The materials of construction and operating environment for components and piping in nonsafety-related and safety-related portions of the SWS are identical. Therefore, the aging effects managed by the Service Water Integrity Program are identical.
>
> As stated in LRA Section B.1.34, the Service Water Integrity Program is consistent with NUREG-1801, Section XI.M20, Open Cycle Cooling Water System and includes activities that apply to both safety-related and nonsafety-related components described below.
>
> 1. Component inspections for erosion, corrosion, and biofouling. Results of these inspections have been used to determine the corrective actions required to preclude recurrence of unacceptable conditions, as described in LRA Section B.0.3. All components in the SWS [service water system] flowpath are within the scope of such corrective actions regardless of safety classification.
>
> 2. Safety-related heat exchangers in the program are tested to verify heat transfer capabilities. Nonsafety-related heat exchangers cooled by service water are periodically inspected. These inspections are sufficient to manage aging effects since there is no license renewal component intended function of heat transfer.
>
> 3. Chemical treatment using biocides and sodium hypochlorite and periodic cleaning and flushing of infrequently used loops are applied to all components in the SWS flowpath regardless of safety classification. In this manner, the program remains effective for managing aging effects for all components in the SWS.
>
> 4. GL 89-13 inspections are performed on nonsafety-related piping. For example, during [refueling outage] 2R18 in March and April 2008, approximately 10% of the scheduled GL 89-13 program volumetric weld examinations were conducted on nonsafety-related SWS piping welds, and approximately 25% of the scheduled GL 89-13 program visual inspections were conducted on nonsafety-related SWS piping. Scope expansion for indications found by GL 89-13 inspections of nonsafety-related piping is based on consideration of location, severity, materials,

previous inspection history, and other relevant factors.

5. System walkdowns apply to both SWS safety-related and nonsafety-related components.

Considering that activities under the Service Water Integrity Program apply to both safety-related and nonsafety-related components, the program effectiveness conclusions of recent peer and self assessments as well as NRC inspections described in the operating experience section are applicable to all components crediting the program for aging management.

The staff noted that the scope of GALL AMP XI.M20, "Open-Cycle Cooling Water System," is applicable to safety-related service water system components that are tied to the ultimate heat sink for the facility. The applicant's response clarifies that it is conservatively applying its Service Water Integrity Program to both the safety-related and nonsafety-related components that are exposed to the service water environment. Thus, based on the staff's review of the Service Water Integrity Program, as amended in the applicant's response to RAI AUX-2, the staff finds the applicant's has provided an acceptable basis for managing aging effects in the nonsafety-related service water system components consistent with the program elements in GALL AMP XI.M20. The staff's concern in RAI AUX-2 is resolved.

<u>UFSAR Supplement</u>. In LRA Sections A.2.1.33 and A.3.1.33, the applicant provided the UFSAR supplement for the Service Water Integrity Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its audit and review of the applicant's Service Water Integrity Program, the staff finds all program elements consistent with the GALL Report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program

<u>Summary of Technical Information in the Application</u>. LRA Section B.1.37 describes the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program as a new program that will be consistent with GALL AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)."

LRA Section B.1.37 states that the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program augments the inspection of reactor coolant system components in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI. The augmented inspection detects the effects of loss of fracture toughness due to thermal aging embrittlement of CASS components. This AMP determines the susceptibility of CASS components to thermal aging embrittlement based on casting method, molybdenum content, and percent ferrite. The program manages aging through either enhanced volumetric examination or flaw tolerance evaluation. Additional inspections or evaluations to demonstrate adequate material fracture toughness are not required for components that are not susceptible to thermal aging embrittlement. In the staff's letter from Christopher Grimes, NRC, to Douglas Walters, NEI, the staff provided its basis for establishing that CASS pump casings and valve bodies do not need to be screened for thermal aging embrittlement. The existing ASME Section XI inspection requirements, including the alternative requirements of ASME Code Case N-481 for pump casings, are adequate for all pump casings and valve bodies.

Staff Evaluation. During its audit and review, the staff reviewed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff reviewed the program elements of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program to verify consistency with GALL AMP XI.M12. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program elements (1) through (6) are consistent with the corresponding elements in GALL AMP XI.M12. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

Operating Experience. LRA Section B.1.37 states that the Thermal Aging Embrittlement of CASS Program is a new program. When implementing this new program the applicant will consider as its basis industry operating experience in the operating experience element of the GALL Report program description. Plant-specific operating experience is not inconsistent with the operating experience in the GALL Report program description.

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program is based on the GALL Report program description, which in turn is based on industry operating experience. Such operating experience assures program management of the effects of aging so components continue to perform intended functions consistent with the CLB through the period of extended operation.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.36 and A.3.1.36, the applicant provided the UFSAR supplement for the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d). The applicant stated in the LRA that this program will be implemented prior to the period of extended operation. In addition, the applicant stated that this new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)" (Commitment 26).

By letter dated July 27, 2009, the applicant added a new commitment (Commitment 40) that states that plant specific and appropriate industry operating experience will be evaluated and lessons learned will be used to establish appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs.

Conclusion. On the basis of its audit and review of the applicant's Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program, the staff finds that all program elements presented in the program basis documents are consistent with the GALL report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program

Summary of Technical Information in the Application. LRA Section B.1.38 describes the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program as a new program that will be consistent with GALL AMP XI.M13, “Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS).”

The Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program augments the reactor vessel internals visual inspection in accordance with the ASME Code, Section XI, Subsection IWB. This augmented inspection manages the effects of loss of fracture toughness due to thermal aging and neutron embrittlement of CASS components. This AMP determines the susceptibility of CASS components to thermal aging or neutron irradiation (neutron fluence) embrittlement based on casting method, molybdenum content, operating temperature, and percent ferrite. For each potentially susceptible component, aging management is through either a component-specific evaluation or a supplemental examination of the affected component as part of the ISI program during the license renewal term.

Staff Evaluation. During its audit and review, the staff reviewed the applicant’s claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program to verify consistency with GALL AMP XI.M13. Details of the staff’s audit of the applicant’s AMP are documented in the Audit Report. As documented in the report, the staff found that the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program elements (1) through (6) are consistent with the corresponding elements in GALL AMP XI.M13. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

Operating Experience. LRA Section B.1.38 states that the Thermal Aging and Neutron Irradiation Embrittlement of CASS Program is a new program. When implementing this new program the applicant will consider as its basis industry operating experience in the operating experience element of the GALL Report program description. Plant-specific operating experience is not inconsistent with the operating experience in the GALL Report program description.

The Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program is based on the GALL Report program description, which in turn is based on industry operating experience. Such operating experience assures program management of the effects of aging so components continue to perform intended functions consistent with the CLB through the period of extended operation.

The staff confirmed that the “operating experience” program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.37 and A.3.1.37, the applicant provided the UFSAR supplement for the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d). The applicant stated in the LRA that this program will be implemented prior to the period of extended operation. In addition, the applicant stated that this new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M13, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)" (Commitment 27).

By letter dated July 27, 2009, the applicant added a new commitment (Commitment 40) that states that plant specific and appropriate industry operating experience will be evaluated and lessons learned will be used to establish appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs.

Conclusion. On the basis of its audit and review of the applicant's Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program, the staff finds all program elements consistent with the GALL report. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2 Programs Consistent with the GALL Report with Exceptions or Enhancements

In LRA Appendix B, the applicant stated that the following programs are, or will be, consistent with the GALL Report, with exceptions or enhancements:

- Aboveground Steel Tanks Program
- Bolting Integrity Program
- Boraflex Monitoring Program
- Diesel Fuel Monitoring Program
- External Surfaces Monitoring Program
- Fatigue Monitoring Program
- Fire Protection Program
- Fire Water System Program
- Flux Thimble Tube Inspection Program
- Masonry Wall Program
- Metal-Enclosed Bus Inspection Program
- Oil Analysis Program
- Reactor Vessel Surveillance Program
- Steam Generator Integrity Program
- Structures Monitoring Program
- Water Chemistry Control - Closed Cooling Water Program
- Water Chemistry Control - Primary and Secondary Program

For programs that the applicant claimed are consistent with the GALL Report, with exception(s) and/or enhancement(s), the staff performed an audit and review to confirm that those attributes or features of the program, for which the applicant claimed consistency with the GALL Report, were indeed consistent. The staff also reviewed the exception(s) and/or enhancement(s) to the GALL Report to determine whether they were acceptable and adequate. The results of the staff's audits and reviews are documented in the following sections.

3.0.3.2.1 Aboveground Steel Tanks Program

Summary of Technical Information in the Application. LRA Section B.1.1 describes the existing Aboveground Steel Tanks Program as consistent with GALL AMP XI.M29, "Aboveground Steel Tanks," with enhancements.

The Aboveground Steel Tanks Program manages loss of material from external surfaces of aboveground carbon steel tanks by periodic visual inspection of external surfaces and thickness measurement of locations inaccessible for visual inspection.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Aboveground Steel Tanks Program to verify consistency with GALL AMP XI.M29. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Aboveground Steel Tanks Program elements "scope of program," "preventive actions," and "parameters monitored or inspected," are consistent with the corresponding elements in GALL AMP XI.M29. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited.

Enhancement 1. In the LRA, the applicant committed to implement the following enhancement to program elements "detection of aging effects," and "acceptance criteria," prior to the period of extended operation: "Revise applicable procedures to perform thickness measurements of the bottom surfaces of the condensate storage tanks, city water tank (IP2), and the fire water tanks once during the first ten years of the period of extended operation."

The staff finds this enhancement acceptable because it establishes the thickness measurements for the bottom surfaces of these tanks as recommended in the GALL Report.

Enhancement 2. In the LRA, the applicant committed to implement the following enhancement to program element "monitoring and trending" prior to the period of extended operation: "Revise applicable procedures to require trending of thickness measurements when material loss is detected."

The staff finds this enhancement acceptable because it establishes the practice of trending of thickness measurements as recommended in the GALL Report.

Operating Experience. LRA Section B.1.1 states that visual inspections detected corrosion on the top of the IP3 condensate storage tank in 2003 and 2005 and on the IP2 condensate storage tank in 2004. Corrective actions cleaned and repainted the surfaces to prevent recurrence. Visual inspections of the external surfaces of the gas turbine fuel storage tanks in December 2006 detected no loss of material due to corrosion.

Thickness measurements of the gas turbine fuel storage tanks in April 2002 found pitting up to 60 percent through-wall with no loss of intended function. This pitting was repaired with a weld overlay. Internal inspections of the IP2 fire water and the training center fire water storage tanks in 2003 detected failure of the coating in several places but no appreciable metal loss, Corrective actions repaired the coating.

The staff confirmed detection of degradation and corrective action prior to loss of intended function assures program effectiveness in managing the aging effects for these passive components.

Furthermore, the staff confirmed that the “operating experience” program element satisfies the criterion defined in the GALL Report and in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.1 and A.3.1.1, the applicant provided the UFSAR supplement for the Aboveground Steel Tanks Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

The applicant has committed to implement the noted enhancements prior to entering the period of extended operation (Commitment 1).

Conclusion. On the basis of its audit and review of the applicant’s Aboveground Steel Tanks Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report, are consistent. Also, the staff reviewed the enhancements to the program elements and confirmed that their implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Program

Summary of Technical Information in the Application. LRA Section B.1.2 describes the existing Bolting Integrity Program as consistent with GALL AMP XI.M18, “Bolting Integrity,” with enhancement.

The Bolting Integrity Program relies on NUREG-1339, “Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants,” recommendations, industry recommendations, and EPRI NP-5769, “Degradation and Failure of Bolting in Nuclear Power Plants,” Volumes 1 and 2, for a comprehensive bolting integrity program with the exceptions noted in NUREG-1339 for safety-related bolting. The program relies on industry recommendations for comprehensive bolting maintenance as in EPRI TR-104213, “Bolted Joint Maintenance & Application Guide,” for pressure-retaining and structural bolting. The program applies bolting and torquing practices of safety- and nonsafety-related bolting for pressure-retaining components, NSSS component supports, and structural joints. The program addresses all bolting regardless of size except reactor head closure studs, which are addressed by the Reactor Head Closure Studs Program. The program periodically inspects closure bolting for signs of leakage that may be due to crack initiation, loss of preload, or loss of material due to corrosion. The program also includes preventive measures to preclude or minimize loss of preload and cracking.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Bolting Integrity Program to verify consistency with GALL AMP XI.M18. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Bolting Integrity Program elements "scope of program," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria," are consistent with the corresponding elements in GALL AMP XI.M18. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited.

Enhancement. In the LRA, the applicant committed to implement the following enhancement to program element, "preventive actions," specifically, "[r]evise applicable procedures to clarify that actual yield strength is used in selecting materials for low susceptibility to SCC and to clarify the prohibition on use of lubricants containing MoS_2 for bolting."

This enhancement is based on EPRI guidance and staff recommendations in NUREG-1339 and is therefore acceptable.

In Audit Item 109, the staff asked the applicant if they have a bolting expert for IP2 and IP3 as recommended in the EPRI guidance. By letter dated March 24, 2008, the applicant stated that the Maintenance Department provides the functions of the expert for bolting in accordance with the EPRI guidance. The staff found this to be acceptable because it is consistent with the EPRI guidance.

In Audit Items 241 and 270, the staff asked the applicant why loss of preload was not an aging effect requiring management. The applicant stated that EPRI Mechanical Tools, EPRI 1010639 (which is an industry guidance document), does not list loss of preload as an aging effect requiring management. The staff stated that other plants have listed loss of preload as an aging effect requiring management and the Bolting Integrity Program used to manage the aging. In addition, the GALL Report lists loss of preload as an aging effect requiring management and lists the Bolting Integrity Program as the appropriate program to manage this aging effect. The applicant stated that the Bolting Integrity Program includes provisions to manage loss of preload. By letter dated December 18, 2007, the applicant revised its commitment and amended the LRA to explicitly state that the Bolting Integrity Program manages the aging effect of loss of preload. The staff finds the applicant's response acceptable because it amended the LRA to manage loss of preload which is consistent with the guidance in the GALL Report.

Operating Experience. LRA Section B.1.2 stated that visual inspections of bolted connections were documented during 2001 through 2005. Although corrosion products were found on some bolting materials, the applicant did not identify any situations where loss of material had precluded the bolted connection from performing its intended function. The applicant completed corrective actions to ensure future integrity of the bolted connection. The applicant concluded that identification of degradation and performance of corrective action prior to loss of intended function provide assurance that the program is effective for managing aging effects for passive components.

The staff notes that the applicant uses plant procedures that address material and lubricant selection, design standards, and good bolting maintenance practices consistent with EPRI guidance that results in few problems with bolting. By controlling the material (i.e., the maximum yield strength), the applicant has not experienced SCC of pressure boundary bolting.

The staff confirmed that the "operating experience" program element satisfies the criterion defined in the GALL Report and in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.2 and A.3.1.2, the applicant provided the UFSAR supplement for the Bolting Integrity Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

The applicant has committed to implement the noted enhancement prior to entering the period of extended operation (Commitment 2). The applicant has also committed to use the Bolting Integrity Program to manage the loss of preload (Commitment 2).

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 enhancement to the program element and confirmed that their implementation prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Boraflex Monitoring Program

Summary of Technical Information in the Application. LRA Section B.1.3 describes the existing Boraflex Monitoring Program as consistent with GALL AMP XI.M22, "Boraflex Monitoring," with exceptions.

The Boraflex Monitoring Program prevents degradation of the Boraflex panels in the spent fuel racks from compromising the criticality analysis supporting the design of the spent fuel storage racks. The program relies on 1) areal density testing, 2) a predictive computer code, and 3) determination of boron loss through correlation of silica levels in spent fuel water samples to maintain the required five percent subcriticality margin. Corrective actions follow if test results find that the five percent subcriticality margin cannot be maintained because of current or projected Boraflex degradation. This program applies to IP2 only as no Boraflex is used for criticality control of IP3 spent fuel.

Staff Evaluation. During its review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff reviewed the program elements of the Boraflex Monitoring Program to verify consistency with GALL AMP XI.M22. Based on the staff's review, the staff determined that Boraflex Monitoring Program elements "scope of program," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria," are consistent with the corresponding elements in GALL AMP XI.M22. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the exceptions to determine whether the program is adequate to manage the aging effects for which it is credited.

Exception 1. In the LRA, the applicant took the following exception to program element "preventive actions": "NUREG-1801 specifies measuring gap formation by blackness testing. The IPEC program specifies areal density measurements for boraflex degradation."

Exception 2. In the LRA, the applicant took the following exception to program element "detection of aging effects": "NUREG-1801 recommends blackness testing as a supplement to areal density measurements for determining gap formations. The IPEC program specifies areal density testing only."

For both exceptions, the applicant provided a footnote which read:

> The NRC Staff, as documented in the SER for Oyster Creek, has accepted the position that areal density measurement in lieu of blackness testing is acceptable. Areal density testing provides a direct measurement of in-rack performance of Boraflex panels through measurement of gaps, erosion, and general thinning. Blackness testing provides only an indication of neutron absorber presence and does not quantitatively measure the Boron-10 areal density of neutron absorber in each rack. Therefore, areal density along with the monitoring of silica levels in the spent fuel pool provides adequate detection of boraflex degradation.

The exceptions to the GALL Report relate to one of the types of periodic tests performed to monitor and detect Boraflex degradation. The GALL Report specifies neutron attenuation/blackness testing be performed to determine gap formation in the Boraflex panels. In response to Audit Item 21, by letter dated December 18, 2007, the applicant stated that areal density measurement (BADGER testing) provides a direct measurement of in-rack performance of the boraflex panels through measurement of gaps, erosion and general thinning and quantitatively measures the Boron-10 areal density. Blackness testing provides an indication of neutron absorber presence only, and does not provide quantitative measurements of the Boron-10 areal density. Therefore, the blackness testing is not required.

The staff reviewed the exceptions and concluded that since the areal density test is more quantitative than the blackness test, these exceptions are acceptable.

In RAI 3.0.3.3.3-1, dated April 18, 2008, the staff noted that the UFSAR, Revision 20, dated 2006, Section 14.2.1 states in part that, "Northeast Technology Corporation report NET-173-01 and NET-171-02 are based on conservative projections of amount of boraflex absorber panel degradation assumed in each sub-region. These projections are valid through the end of the year <u>2006</u>." The staff requested that the applicant confirm that the Boraflex neutron absorber panels in the IP2 spent fuel pool have been re-evaluated for service through the end of the current licensing period, and that the applicant provides information on their plans for updating the Boraflex analysis during the period of extended operation.

In its response, dated May 16, 2008, the applicant provided the following information. BADGER testing was performed in February 2000, July 2003, and July 2006. The latest test data and RACKLIFE [a computer-generated value of boron loss] predictive code indicate that the Boraflex neutron absorbing panels will meet the TS requirements through the end of the current licensing period. The next BADGER test will be performed prior to the end of calendar year 2009. Periodic BADGER testing and RACKLIFE projections will continue through the period of extended operation to confirm acceptable Boraflex condition. The appropriate UFSAR section will be updated in the next revision to reflect this.

By letter dated October 20, 2008, the applicant transmitted the most recent UFSAR which included the following statement:

> Based upon BADGER testing in calendar years 2003 and 2006 and RACKLIFE code projections, the validity of the criticality and boron dilution analysis documented in NET-173-01 and NET-173-02 can be extended through the end of the current license (September 30, 2013), provided BADGER testing is performed during calendar year 2009 and again in 2012 to confirm the progression of localized Boraflex dissolution.

Because the applicant updated its UFSAR to reflect that the analysis will be valid through the end of the current license, the staff's concern is resolved.

<u>Operating Experience</u>. LRA Section B.1.3 states that panels of Boraflex maintain adequate subcriticality of the fuel in the spent fuel racks. As Boraflex is susceptible to in-service degradation, the applicant developed a RACKLIFE model of the IP2 spent fuel pool. Results of Boron-10 areal density gage for evaluating racks (BADGER) testing in February 2000, July 2003, and again in July 2006, confirmed the predictions of the RACKLIFE computer model and proved that the program effectively manages change in material properties (reduction in neutron-absorbing capacity) for Boraflex neutron absorber panels.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10.

The GALL Report, Section XI.M22 in "Operating Experience," states:

> The experience with Boraflex panels indicates that coupon surveillance programs are not reliable. Therefore, during the period of extended operation, the measurement of boron areal density correlated, through a predictive code, with silica levels in the pool water is verified. These monitoring programs provide assurance that degradation of Boraflex sheets is monitored, so that appropriate actions can be taken in a timely manner if significant loss of neutron-absorbing capability is occurring. These monitoring programs ensure that the Boraflex sheets will maintain their integrity and will be effective in performing its intended function.

The applicant has provided information in a response to an Audit Item, and has updated its UFSAR to reflect the performance of BADGER testing. Therefore, the staff finds that the applicant has considered the appropriate plant-specific and industry operating experience.

UFSAR Supplement. In LRA Section A.2.1.3, the applicant provided the UFSAR supplement for the Boraflex Monitoring Program. The staff reviewed this section and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Boraflex Monitoring Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exceptions and their justifications and determines that the program is adequate to manage the aging effects for which it is credited. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Diesel Fuel Monitoring Program

Summary of Technical Information in the Application. LRA Section B.1.9 describes the existing Diesel Fuel Monitoring Program as consistent with GALL AMP XI.M30, "Fuel Oil Chemistry," with exceptions and enhancements.

The Diesel Fuel Monitoring Program entails sampling for whether adequate diesel fuel quality is maintained to prevent loss of material and fouling in fuel systems. Periodic draining and cleaning of tanks and verification of new oil quality before its introduction into the storage tanks minimize exposure to fuel oil contaminants (e.g., water, microbiological organisms). Sampling and analysis are in accordance with the IP2 and IP3 fuel oil purity technical specifications and ASTM Standards D4057-95 and D975-95 (or later revisions of these standards). Thickness measurements of storage tank bottom surfaces verify whether degradation has occurred. The One-Time Inspection Program describes inspections planned to verify the effectiveness of the Diesel Fuel Monitoring Program.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Diesel Fuel Monitoring Program to verify consistency with GALL AMP XI.M30. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Diesel Fuel Monitoring Program element "corrective actions" is consistent with the corresponding element in GALL AMP XI.M30. Because this element is consistent with the GALL Report element, the staff finds that it is acceptable.

As documented in the Audit Report, the staff verified the sampling frequencies for the EDGs, gas turbine generators, diesel fire pump, Appendix R diesel generators, and security diesel generator fuel oil storage tanks. Enhancements to the Diesel Fuel Monitoring Program, discussed below, include draining, cleaning, and inspection and bottom thickness measurement once every ten years for the gas turbine generators fuel oil storage tanks, the EDGs fuel oil storage and day tanks, and the Appendix R diesel generators fuel oil storage and day tanks. In addition, an enhancement to the Diesel Fuel Monitoring Program provides for periodic sampling, near the bottom, once per month to determine water content in the gas turbine generators fuel oil storage tanks, the EDGs fuel oil storage and day tanks, the diesel fire pumps storage tanks, the security diesel generator storage tank, and the Appendix R diesel generators fuel oil storage tanks. The staff determined that the sampling frequencies are consistent with current industry standards, and are consistent with the plant technical specifications. The sampling frequencies will provide for timely detection of fuel oil contamination, and will allow corrective actions to be taken, as needed, prior to the loss of intended function. On this basis, the staff finds these sampling frequencies acceptable.

The staff reviewed the exceptions and enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited.

Exception 1. In the LRA, the applicant took the following exception to the GALL Report program element "scope of program": "NUREG-1801 recommends use of ASTM Standards D2276 and D6217. Particulate testing is performed using the guidelines of ASTM Standard D2276."

The staff noted that the discussion of this exception in LRA Section B.1.9 includes a footnote, which states the following: "ASTM Standard D6217 (particulate by filtration) is not used for determination of particulate. Particulate testing is performed using standard D2276. The guidelines of D2276 are appropriate for determination of particulates and the plant technical specifications specify this standard."

The staff noted that GALL Report, Section XI.M30 recommends ASTM D2276 and D6217 for the measurement of particulates in diesel fuel. The staff reviewed both standards and determined that the guidelines of D2276 are appropriate for determination of particulates and the plant technical specifications specify this standard. Therefore, the staff concludes that this exception is acceptable.

Exception 2. In the LRA, the applicant took the following exception to the GALL Report program elements "scope of program," "parameters monitored or inspected," and "acceptance criteria": "NUREG-1801 recommends use of ASTM Standards D1796 and D2709. Only ASTM Standard D1796 is used for testing water and sediment."

The staff noted that the discussion of this exception in LRA Section B.1.9 includes a footnote, which states the following: "The guidelines of ASTM Standard D1796 are used rather than those of ASTM Standard D2709 (water and sediment by centrifuge for lower viscosities) for determination of water and sediment. The two standards are applicable to oils of different viscosities. Standard D1796 is applicable to the fuel oil used at IPEC."

ASTM Standard D1796 and 2709 are applicable to oils of different viscosities. Although the GALL Report specifies the use of ASTM Standard D2709, ASTM Standard D1796 is applicable to the fuel oil used at IP. Determination of water and sediment are established in site procedures. The staff also confirmed that the guidance presented in ASTM standard D1796 applies to fuel oils with the viscosity of that used at IP2 and IP3. Therefore, the staff concludes that this exception is acceptable.

Exception 3. In the LRA, the applicant took the following exception to the GALL Report program element "preventive actions": "NUREG-1801 specifies fuel oil is maintained by addition of biocides. IPEC does not add biocide to diesel fuel oil storage tanks."

The staff noted that the discussion of this exception in the Diesel Fuel Monitoring Program includes a footnote, which states the following:

> IPEC does not add biocides to diesel fuel oil storage tanks. Since water contamination in the diesel fuel oil storage tanks is minimized, the potential for MIC [microbiologically-influenced corrosion] is limited. The IPEC process for review of site and industry operating experience ensures that if MIC is discovered during future analyses, appropriate corrective actions will be taken, including modification of program attributes, if appropriate.

The IP2 and IP3 program does not add biocides to diesel fuel oil storage tanks on a routine basis to prevent biological breakdown of the diesel fuel (i.e., microbiologically-influenced corrosion). Rather, the program is focused on limiting the potential for microbiologically-influenced corrosion by minimizing the water concentration of the fuel. If the results of routine samples indicate evidence of MIC activity, the need for biocides is evaluated under the corrective action program. If the evaluation deems them necessary to correct the condition, biocides will be used. This practice is consistent with guidance contained in ASTM Special Technical Publication 1005, "Distillate Fuel: Contamination, Storage and Handling." Based on operating history and FO management activities, the addition of biocides, biological stabilizers, and corrosion inhibitors into stored fuel is not necessary; however, the option is retained on an as-needed basis.

Since water contamination in the diesel fuel storage tanks is minimized, the potential for microbiologically-influenced corrosion is limited. The staff confirmed that the applicant's process for review of site and industry operating experience ensures that if microbiologically-influenced corrosion is discovered during future analyses, appropriate corrective actions will be taken, including modification of program attributes, if appropriate. Therefore, the staff finds that this exception is acceptable.

Exception 4. In the LRA, the applicant took the following exceptions to the GALL Report program elements "parameters monitored or inspected" and "acceptance criteria," which were revised by Amendment 1 to the LRA, Attachment 1, Audit Item 131, dated December 18, 2007. Specifically, the exception stated, "[f]or determination of particulates, NUREG-1801 recommends use of modified ASTM Standard D2276 Method A and D6217. Determination of particulates is according to ASTM Standard D2276."

The staff noted that the discussion of this exception in Section B.1.9 of the LRA includes a footnote. The footnote to this exception was revised by Amendment 1 to the LRA, Attachment 1, Audit Item 131, dated December 18, 2007. The revised footnote states the following:

> Determination of particulates is according to ASTM Standard D2276 which conducts particulate analysis using a 0.8 micron filter, rather than the 3.0 micron filter specified in NUREG-1801. Use of a filter with a smaller pore size results in a larger sample of particulates since smaller particles are retained. Thus, use of a 0.8 micron filter is more conservative than use of the 3.0 micron filter specified in NUREG-1801. ASTM D6217 applies to middle distillate fuel using a smaller volume of sample passing over the 0.8 micron filter. Since ASTM D2276 determines particulates with a larger volume passing through the filter for a longer time than the D6217 method, use of D2276 only is more conservative.

The staff noted that GALL Report Section XI.M30 recommends modified ASTM D2276, Method A, and ASTM D6217 for the measurement of particulates in diesel fuel. The modification to D2276 consists of using a filter with a pore size of 3.0 micron, instead of 0.8 micron. The staff reviewed both standards and determined that the guidelines of D2276 are appropriate for determination of particulates at IP and the use of a 0.8 micron filter is more conservative than use of the 3.0 micron filter since ASTM D2276 determines particulates with a larger volume passing through the filter for a longer time than the D6217 method. Therefore, the staff concluded that this exception is acceptable.

Enhancement 1. In the LRA, the applicant committed to implement the following enhancement to program elements “preventive actions” and “detection of aging effects”:

> IP2: Revise applicable procedures to include cleaning and inspection of the GT1 gas turbine fuel oil storage tanks, EDG fuel oil day tanks, and SBO/Appendix R diesel generator fuel oil day tank once every ten years.
>
> IP3: Revise applicable procedures to include cleaning and inspection of the EDG fuel oil day tanks, Appendix R fuel oil storage tank, and Appendix R fuel oil day tank once every ten years.

As discussed in the applicant’s procedures, the EDG and GT2/3 gas turbine fuel storage tanks are cleaned and inspected every ten years to remove sludge, debris, and water. Program enhancements are needed to include the GT1 storage tank, EDG fuel oil day tanks, Appendix R fuel oil storage tank and the SBO/Appendix R diesel generator fuel oil day tanks.

The GT1 tanks are monitored in accordance with technical specifications on fuel oil purity and the guidelines of ASTM Standards D1796 (water and sediment by centrifuge), D2276 (particulate gravimetrically), and D4057 (sampling). In addition the GT1 gas turbine fuel oil storage tanks, EDG fuel oil day tanks, and SBO/Appendix R diesel generator fuel oil day tank are periodically sampled, near the bottom, to determine water content. The frequencies and acceptance criteria are documented in the applicant’s procedures.

In Audit Item 36, the staff asked the applicant to provide a technical basis for the 10-year inspection frequency. In its response, dated March 24, 2008, the applicant stated that the basis for the 10-year wall thickness inspection frequency is to perform the inspections in conjunction with other 10-year inspections and cleanings. This inspection frequency is consistent with the recommended frequency in RG 1.137 and meets New York State regulations for fuel oil storage tanks. Past visual inspections of fuel oil storage tanks have not detected significant degradation that would lead to a need for an increased inspection frequency.

The staff determined that the applicant’s enhancement will add routine draining, cleaning, and visual inspections, and ultrasonic measurement of the bottom surfaces of the diesel generators fuel oil storage tanks and day tanks and gas turbine generators fuel oil storage tanks, which are consistent with the recommendations in the GALL Report. The frequency for draining, cleaning and inspecting the tanks will be based on past experience, which has been demonstrated to provide acceptable performance for the diesel fuel storage tanks. The enhancement to the diesel fuel oil monitoring program ensures that significant degradation is not occurring. On this basis, the staff found this enhancement acceptable.

Enhancement 2. In the LRA, the applicant committed to implement the following enhancement to program elements "preventive actions," "detection of aging effects," and "monitoring and trending":

> IP2: Revise applicable procedures to include quarterly sampling and analysis of the SBO/Appendix R diesel generator fuel oil day tank and security diesel fuel oil day tank. Particulates (filterable solids), water and sediment checks will be performed on the samples. Filterable solids acceptance criterion will be < 10mg/l. Water and sediment acceptance criterion will be < 0.05%.
>
> IP3: Revise applicable procedures to include quarterly sampling and analysis of the Appendix R fuel oil storage tank. Particulates (filterable solids), water and sediment checks will be performed on the samples. Filterable solids acceptance criterion will be < 10mg/l. Water and sediment acceptance criterion will be < 0.05%.

As described in the applicant's procedures, IP2 and IP3 perform periodic multi-level sampling to provide assurance that fuel oil contaminants are within acceptable limits. Water and particulate concentrations are monitored and trended at least quarterly or in accordance with technical specifications. This enhancement expands scope of existing procedures to include quarterly sampling and analysis of all tanks within the scope of license renewal.

During the regional inspection conducted in February 2008, the inspectors identified that the IP2 security diesel fuel oil storage tank was not included in the program enhancement to perform fuel oil chemistry sampling. By letter dated March 24, 2008, the applicant amended the above enhancement to include quarterly sampling of the IP2 security diesel fuel oil storage tank.

The staff determined that the applicant's enhancement will add routine diesel fuel oil sampling and analysis for the SBO/Appendix R diesel generator fuel oil day tank (IP2), the Appendix R fuel oil storage tank (IP3), and the security diesel fuel oil storage and day tanks (IP2), which is consistent with the recommendations in the GALL Report. The frequency for sampling and analysis is consistent with the technical specifications where applicable. The enhancement to the diesel fuel oil monitoring program ensures that fuel oil quality is maintained. On this basis, the staff finds this enhancement acceptable.

Enhancement 3. In the LRA, the applicant committed to implement the following enhancement to program element "detection of aging effects":

> IP2: Revise applicable procedures to include thickness measurement of the bottom surface of the EDG fuel oil storage tanks, EDG fuel oil day tanks, SBO/ Appendix R diesel generator fuel day tank, GT1 gas turbine fuel oil storage tanks, and diesel fire pump fuel oil storage tank once every ten years.
>
> IP3: Revise applicable procedures to include thickness measurement of the bottom surface of the EDG fuel oil day tanks, Appendix R fuel oil storage tank, and diesel fire pump fuel oil storage tank once every ten years.

The enhancement is necessary to provide periodic thickness measurement monitoring for all tanks within scope of license renewal. Presently, the only diesel fuel oil tanks with procedures or tasks requiring NDE of the tank bottom are the IP3 EDG storage tanks and the GT2/3 storage tank. These inspections are described in the applicant's procedures. The minimum acceptable thickness for each tank bottom when inspected is based upon a component-specific engineering evaluation. Wall thickness will be acceptable if greater than the minimum wall thickness for the specific component.

As described in the applicant's procedure, thickness measurements are performed once every ten years on the IP3 EDG fuel oil storage tanks to verify that significant degradation is not occurring. The Aboveground Steel Tanks Program includes thickness measurement of the GT2/3 fuel oil storage tank once every ten years. Enhancement is also needed to specify acceptance criteria for thickness measurements of the fuel oil storage tanks within the scope of the program (see Enhancement 5, below).

The staff determined that the applicant's enhancement will add routine draining, cleaning, visual inspections, and ultrasonic measurement of the bottom surfaces of the diesel fuel tanks, which are consistent with the recommendations in the GALL Report. The frequency for draining, cleaning and inspecting the tanks will be based on past experience, which has been demonstrated to provide acceptable performance for the diesel fuel storage tanks. Ultrasonic measurement of the tank bottoms will provide objective evidence that degradation of the tanks is not occurring. The staff finds that the selection of the tank bottoms for ultrasonic inspection is appropriate since any moisture in the oil will tend to settle to the bottom of the tanks, making this the most susceptible location for degradation. On this basis, the staff found this enhancement acceptable.

Enhancement 4. In the LRA, the applicant committed to implement the following enhancement to program element "monitoring and trending":

> IP2: Revise appropriate procedures to change the GT1 gas turbine fuel oil storage tanks and diesel fire pump fuel oil storage tank analysis for water and particulates to a quarterly frequency.
>
> IP3: Revise appropriate procedures to change the Appendix R fuel oil day tank and diesel fire pump fuel oil storage tank analysis for water and particulates to a quarterly frequency.

The enhancement is necessary to address all tanks within scope of license renewal. The diesel fuel oil sampling and analysis frequencies for water and particulates are included in the applicant's procedures and the technical specifications, as applicable.

The staff determined that the applicant's enhancement will add routine quarterly frequency diesel fuel oil sampling and analysis from the GT1 gas turbine generator and diesel fuel oil storage tanks at IP2 and the Appendix R diesel generator fuel oil day tank and the diesel fire pump storage tank at IP3, which are consistent with the recommendations in the GALL Report. The frequency for sampling and analysis is consistent with the technical specifications where applicable. The enhancement to the diesel fuel oil monitoring program ensures that fuel oil quality is maintained. On this basis, the staff found this enhancement acceptable.

Enhancement 5. In the LRA, the applicant committed to implement the following enhancement to program element "acceptance criteria": "[r]evise applicable procedures to specify acceptance criteria for thickness measurements of the fuel oil storage tanks within the scope of the program."

The enhancement is necessary to specify acceptance criteria for thickness measurements for all tanks within scope of license renewal. See Enhancement 3, above.

Presently, the only diesel fuel oil tanks with procedures or tasks requiring NDE of the tank bottom are the IP3 EDG storage tanks and the GT2/3 storage tank. These inspections are described in plant procedures. The minimum acceptable thickness for each tank bottom when inspected is based upon a component-specific engineering evaluation. Wall thickness will be acceptable if greater than the minimum wall thickness for the specific component.

The staff determined that the applicant's enhancement will specify acceptance criteria for thickness measurements of diesel generator fuel storage tanks within the scope of this program, which is consistent with the recommendations in the GALL Report. The acceptance criteria will provide a measure to determine whether corrective actions are required based upon inspection results. On this basis, the staff finds this enhancement acceptable.

Enhancement 6. In Amendment 1 to the LRA, dated December 18, 2007, in response to Audit Item 128, the applicant committed to implement the following enhancement to program element "preventive actions": "[r]evise applicable procedures to direct samples to be taken near the tank bottom and include direction to remove water when detected."

The enhancement is necessary to ensure that applicable fuel oil sampling procedures include specific direction to obtain samples near the bottom of all tanks within scope of this program in order to more accurately determine the water content. If large amounts of water are encountered the applicable fuel oil sampling procedures will provide direction to remove water from the bottom of the tank. This commitment was included in Amendment 1 to the LRA, dated December 18, 2007.

By letter dated December 18, 2007, in response to the staff's inquiries about how water content of fuel oil tanks was to be determined and how removal of water from the bottoms of fuel oil tanks was to be implemented, the applicant stated that procedure 0-CY-1810, which covers the monitoring of all diesel fuel oil on the site, will be enhanced to include direction to take samples near the tank bottom for water detection and to remove water from the tank bottom if detected (Audit Item 128).

The staff determined that the applicant's program and procedure enhancement will adequately detect the water near the bottom of fuel oil tanks within scope of this program and provide direction to remove water from the tanks when it is detected, which is consistent with the recommendations in the GALL Report. The preventive actions will provide administrative controls to detect water near the bottom of fuel oil tanks and provide direction to remove water from the tanks when it is detected. On this basis, the staff finds this enhancement acceptable.

Enhancement 7. In Amendment 1 to the LRA, dated December 18, 2007, in response to Audit Item 132, the applicant committed to implement the following enhancement to program element "preventive actions": "[r]evise applicable procedures to direct the addition of chemicals including biocide when the presence of biological activity is confirmed."

The enhancement is necessary to ensure that applicable administrative controls are in place to direct the addition of biocides to control biological activity when it is detected in fuel oil tanks within scope of this program as recommended in the GALL Report to prevent biological breakdown of the diesel fuel. This commitment was included in Amendment 1 to the LRA, dated December 18, 2007.

By letter dated December 18, 2007, in response to the staff's inquiries about the addition of biocides to control biological activity in diesel fuel oil, the applicant stated that the corrective actions program is used to evaluate microbiological activity and determine the need for the use of biocides (Audit Item 132). The applicant follows the guidelines of ASTM Special Technical Publication 1005, "Distillate Fuel: Contamination, Storage, and Handling," with regard to the addition of biocides to diesel fuel oil. In order to make the procedures regarding the addition of biocides to diesel fuel oil consistent between IP2 and IP3, the applicant stated that an enhancement will be added to combine the directions from unit procedures into series procedure for the addition of chemicals, including biocide, on both units when the presence of biological activity is confirmed.

The staff determined that the applicant's program and procedure enhancement will adequately provide direction for the addition of chemicals, including biocide, to the diesel fuel oil storage tanks within the scope of this program on both units when the presence of biological activity is confirmed. The preventive actions will provide administrative controls to direct the addition chemicals, including biocide, to the diesel fuel oil storage tanks when the presence of biological activity is confirmed. On this basis, the staff finds this enhancement acceptable.

Enhancement 8. During the regional inspection, the inspectors identified that the existing procedure for fuel oil transfer using the emergency fuel oil transfer trailer did not specify a that chemistry oil sample be taken at the tank bottom, and did not provide specific acceptance criteria as to when tank flushing would be required. In Amendment 3 to the LRA, dated March 24, 2008, the applicant committed to implement the following enhancement to program element "preventive actions": "[r]evise applicable procedures to direct sampling of the onsite portable fuel oil tanker contents prior to transferring the contents to the storage tanks."

The staff determined that the applicant's program and procedure enhancement will provide direction for sampling the portable fuel oil tanker contents prior to transfer to the storage tanks. The preventive actions will provide administrative controls to ensure that possible contaminants will not be transferred into the emergency diesel fuel oil supply system. On this basis, the staff finds this enhancement acceptable.

Operating Experience. LRA Section B.1.9 states that results of a vendor microorganism study of a sample taken from an EDG underground diesel fuel tank reported heavy bacteria growth. The source of the bacteria was water intrusion through an overfill line spool piece incorrectly reassembled following maintenance. After removal of the water from the tank, testing found no bacteria. Detection of out-of-specification fuel conditions demonstrates the program's ability to detect potentially detrimental diesel fuel conditions. Subsequent corrective actions enhance the program's ability to remain effective in managing loss of component material.

A QA surveillance in 2004 found the overall program effective. One deficiency found and corrected was a missed surveillance. Detection of program deficiencies and subsequent corrective actions add assurance that the program will continue to manage loss of component material effectively.

Other than the noted instances, fuel oil sampling results from 2001 through 2005 reveal that fuel oil quality is maintained in compliance with acceptance criteria. Continuing acceptable diesel fuel quality assures program effectiveness in managing loss of fuel system component material.

Visual inspection of an IP3 EDG fuel oil storage tank in 2001, visual and ultrasonic testing inspections of the two other EDG fuel oil storage tanks in 2001, and visual inspection of the IP2 fuel oil storage tanks in 2003 found no significant degradation.

The staff's review of the operating experience presented by the applicant indicates diesel fuel oil qualify has been maintained and that out-of-specification or deteriorating condition have been detected and corrected. The staff determined that the applicant's program, with the implementation of the proposed procedure enhancements, will adequately maintain diesel fuel oil quality for the tanks within the scope of the program.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.8 and A.3.1.8, the applicant provided the UFSAR supplement for the Diesel Fuel Monitoring Program. In response to Audit Items 128 and 132, in Amendment 1 to the LRA, dated December 18, 2007, the applicant revised LRA Sections A.2.1.8 and A.3.1.8 to include the following (Commitment 4):

> Revise applicable procedures to direct samples taken near the tank bottom and include direction to remove water when detected.
>
> Revise applicable procedures to direct the addition of chemicals including biocides when the presence of biological activity is confirmed.

In Amendment 3 to the LRA, Attachment 1, dated March 24, 2008, the applicant added the following enhancement and committed to implementing it prior to the period of extended operation (Commitment 4):

> Revise applicable procedures to direct sampling of the onsite portable fuel oil tanker contents prior to transferring the contents to the storage tanks.

The staff reviewed these sections and determines that the information in the UFSAR supplement, as amended, is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Diesel Fuel Monitoring Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report, are consistent. In addition, the staff reviewed the exceptions and their justifications and determines that the program is adequate to manage the aging effects for which it is credited. Also, the staff reviewed the enhancements to the program elements and confirmed that their implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 External Surfaces Monitoring Program

Summary of Technical Information in the Application. LRA Section B.1.11 describes the existing External Surfaces Monitoring Program as consistent with GALL AMP XI.M36, "External Surfaces Monitoring," with enhancement.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the External Surfaces Monitoring Program to verify consistency with GALL AMP XI.M36. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the External Surfaces Monitoring Program elements "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria," are consistent with the corresponding elements in GALL AMP XI.M36. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited.

Enhancement. In the LRA, the applicant committed to implement the following enhancement to the program element "scope of program":

> External Surfaces Monitoring Program guidance documents will be revised to require periodic inspections of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4 (a)(1) and (a)(3). Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4 (a)(2).

The staff reviewed the proposed enhancement and finds it acceptable because implementation of the enhancement will result in the periodic inspection of those systems identified by the applicant as within the scope of license renewal in accordance with 10 CFR 54.4(a), which is consistent with the GALL Report.

Operating Experience. In LRA Section B.1.11, the applicant summarizes the operating experience review it performed for the External Surfaces Monitoring program. The applicant reviewed operating experience for the five-year period covering 2001 through 2005, for both IP2 and IP3. The review was documented in a report that was reviewed by the staff during an onsite review. As stated in LRA Section B.0.4, for monitoring programs, such as the External Surfaces Monitoring program, the applicant reviewed sample results to determine if parameters are being maintained as required by the program. During an audit, the staff reviewed the sample results produced by the applicant, and in addition, independently reviewed additional reports that contained keywords such as rust/rusted/rusting, residue, corroded, encrustation, paint, flakes/flaking, etc. Such keywords would likely be included in condition reports to describe a degraded exterior surface of a component. Based on the review of the applicant-identified operating experience, and the independent review of additional condition reports, the staff has confirmed that the applicant has addressed operating experience related to this program, and has identified the applicable aging effects, i.e., loss of material, which is the aging effect identified by the GALL Report for this AMP. Therefore, the staff determines that the applicant has adequately addressed this program element.

UFSAR Supplement. In LRA Sections A.2.1.10 and A.3.1.10, the applicant provided the UFSAR supplement for the External Surfaces Monitoring Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

As documented in LRA Sections A.2.1.10 and A.3.1.10, the applicant has committed to enhance this program prior to entering the period of extended operation (Commitment 5).

Conclusion. On the basis of its review of the applicant's External Surfaces Monitoring Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancement to the program element and confirmed that its implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. Lastly, the staff confirmed that the applicant addressed operating experience related to this program, and identified the applicable aging effects. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Fatigue Monitoring Program

Summary of Technical Information in the Application. LRA Section B.1.12 describes the existing Fatigue Monitoring Program as consistent with GALL AMP X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary," with exception and enhancement.

The Fatigue Monitoring Program tracks the number of critical thermal and pressure transients for selected reactor coolant system components to validate the analyses of fatigue transients by assuring that the actual effective number does not exceed the analyzed number of transients.

In a letter dated January 22, 2008, the applicant amended LRA Section B.1.12, Fatigue Monitoring, to provide detailed information on the cycles counting and the methodology that will be used for the determination of stresses and fatigue usage, including the environmental effects.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Fatigue Monitoring Program to verify consistency with GALL AMP X.M1. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Fatigue Monitoring Program elements "scope of program," "preventive actions," "monitoring and trending," and "acceptance criteria," are consistent with the corresponding elements in GALL AMP X.M1. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the exception and enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited.

During the audit, the staff asked the applicant to provide more information regarding the actions or alarm limits that will trigger the corrective action for the applicant to update fatigue usage calculations (Audit Item 40). In a letter dated March 24, 2008, the applicant stated that, in accordance with their procedure, alert levels will be calculated by adding twice the number of cycles from the last fuel cycle to the total number of cycles to date. The applicant stated that they will take corrective actions if this alert level is greater than the analyzed transients.

In a letter dated April 18, 2008, in RAI 4.3.1.8-2, the staff also asked the applicant to explain the corrective actions and the frequency of such actions if the alert level is approached. In the applicant's response, dated May 16, 2008, the applicant explained that the frequency of updates for the counting of plant transients is at least once each operating cycle, and these updates determine if design transients may be exceeded before the next update. The applicant also stated that corrective actions will be taken prior to exceeding the analyzed transient cycles.

The staff finds the applicant's response acceptable because the applicant will perform periodic updates on the counting of plant transients, which ensures that design transients will not be exceeded and will allow adequate time for corrective actions to be initiated based on the alert level from the applicant's procedure on cycle counting and tracking. These corrective actions include further re-analysis or repair or replacement of the affected components. The staff also finds the applicant's response acceptable because the applicant will appropriately include the new or updated CUF calculations for all NUREG/CR-6260 locations identified in LRA Tables 4.3-12 and 4.3-13 to be a part of the Fatigue Monitoring Program and the incurred cycles will be monitored and the applicant will ensure that they do not exceed the analyzed number of cycles. Based on the staff's conclusions this issue is resolved.

Exception. The staff noted that the applicant originally took exception to the "detection of aging effects" program element of the GALL AMP X.M1 recommendation. The applicant stated that "updates of fatigue usage calculations are not necessary unless the number of accumulated fatigue cycles approaches the number of analyzed design cycles." In a letter dated January 22, 2008, the applicant amended the LRA with respect to its basis for its environmentally-assisted fatigue analysis. In this letter, the applicant provided clarification regarding the relationship between Commitment 33 and the FMP. The applicant stated that as part of Commitment 33, refined CUF calculations will be provided to the NRC. The applicant amended the LRA so that Commitment 33 is within the scope of the applicant's Fatigue Monitoring Program and to credit this AMP as the basis for accepting this TLAA and other TLAAs described in LRA Section 4.3.1.1 through 4.3.1.8 in accordance with 10 CFR 54.21(c)(1)(iii).

During a teleconference with the applicant on April 3, 2008, the staff asked the applicant if the exception to the "detection of aging effects" program element in GALL AMP X.M1 will still be taken based on the applicant's changes made in LRA Amendment 2, dated January 22, 2008. The applicant's proposed change to have refined CUF calculations is consistent with the NRC's recommendations for the periodic CUF updates in the "detection of aging effects" program element of GALL AMP X.M1. Also the applicant stated in Commitment No.33 that the actions to replace or repair components before exceeding a CUF of 1.0 are consistent with the corrective actions recommended in the program element, "corrective action" program element of GALL AMP X.M1.

The staff verified that, in a letter dated June 11, 2008, the applicant amended the LRA and removed the exception to the "detection of aging effects" program element in GALL AMP X.M1. Based on this assessment and the applicant's removal of the exception taken to GALL AMP X.M1 and clarification on the corrective actions for the program, the staff concludes that the "detection of aging effects" and "corrective actions" program elements for the Fatigue Monitoring Program are consistent with and conform to the staff's "detection of aging effects" and "corrective actions" program element criteria that are recommended in GALL AMP X.M1 without exception, and that these program elements are, therefore, acceptable. The staff's question on the exception taken to GALL AMP X.M1 is resolved.

Enhancement. In the LRA, the applicant committed to implement the following enhancement to the program element "parameters monitored or inspected":

> IP2: Perform an evaluation to confirm that monitoring steady state cycles is not required or revise appropriate procedures to monitor steady state cycles. Review the number of allowed events and resolve discrepancies between reference documents and monitoring procedures.
>
> IP3 Enhancements: Revise appropriate procedures to include all the transients identified. Assure all fatigue analysis transients are included with the lowest limiting numbers. Update the number of design transients accumulated to date.

During the audit, the staff noted that in the LRA the IP2 enhancement included monitoring steady state cycles, but the program basis document discussed both steady state cycles and feedwater cycles. The staff asked the applicant to clarify the discrepancy (Audit Item 164).

In a letter dated March 24, 2008, the applicant submitted an amendment to the LRA, and stated that feedwater cycles are included in the enhancement. The staff reviewed these changes and noted that the revised statement is in agreement with the Commitment 6. Therefore, the staff finds the applicant's response acceptable.

The staff finds that after implementation of these enhancements, the "parameters monitored or inspected" program element will be consistent with the staff's "parameters monitored or inspected" program element criteria that are recommended in GALL AMP X.M1. On this basis, the staff finds these enhancements acceptable.

The staff reviewed those portions of the Metal Fatigue of Reactor Coolant Pressure Boundary Program for which the applicant claims consistency with GALL AMP X.M1 and finds that they are consistent with the GALL Report AMP. The staff finds the applicant's Metal Fatigue of Reactor Coolant Pressure Boundary Program acceptable because it conforms to the recommended AMP, as subject to the enhancements that have been discussed and evaluated in the previous paragraphs and that have been incorporated into Commitment 6.

Operating Experience. LRA Section B.1.12 states that the program re-evaluates usage factors as appropriate (e.g., certain auxiliary transients related to charging and letdown approaching typical design cycle limits for the IP2 charging nozzles during the current period of operation). The assessment of impact of thermal transient cycles on the IP2 nozzles compared plant-specific against previously-assumed moment loads and reconciled the cycle counts to design cycles in previous analysis. The reevaluation concluded that the fatigue impact of transient cycles accumulated on the IP2 charging nozzles is within expectations based on pro-rated typical operation of the charging system and projected allowable cycles during the current period of operation.

The staff noted, from the applicant's license renewal plant operating experience review report for this AMP, that the applicant has factored in industry experience, which includes the thermal and operating stresses that were not considered during the original plant design related to NRC Bulletins 88-08 and 88-11, and will continue to factor in industry experience in the IP Fatigue Monitoring Program. During the audit, the staff reviewed implementing procedures and problem identification reports related to the applicant's Metal Fatigue Program. The staff noted that the applicant demonstrated that the program monitors transients and tracks their accumulation based on the applicant's implementing procedure. The staff noted that the applicant tracked and monitored reactor shutdowns and startups and their cycle limitations did not indicate that the allowable number of cycles would be exceeded. The staff also interviewed the applicant's technical staff who have specialized knowledge of the program. The staff reviewed instances previously documented by the applicant that identified issues with the Metal Fatigue Program and where the applicant had implemented corrective actions. The staff's review demonstrated that the operating experience shows that this program effectively manages aging effects; therefore, continued implementation of the program assures management of the effects of aging so components crediting this program will perform intended functions consistent with the CLB during the period of extended operation

Based on this review, the staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.11 and A.3.1.11, the applicant provided the UFSAR supplement for the Fatigue Monitoring Program. By letter dated March 24, 2008, the applicant revised LRA Section A.2.1.11 to include feedwater cycles (in response to Audit Item 164). The staff reviewed these LRA sections, as revised, and the amendments made to Commitments 6 and 33. The staff verified that LRA Sections A.2.1.11 and A.3.1.11 include Commitment 6. The staff also verified that the applicant amended the Fatigue Monitoring Program to incorporate the corrective actions for the applicant's TLAA on metal fatigue, as defined in Commitment 33. Based on this review, the staff finds that the UFSAR Supplement Sections A.2.11 and A.3.1.11, as amended by letter dated January 22, 2008, and as revised by letter dated March 24, 2008, provide an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's Fatigue Monitoring Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the enhancement to the program element and confirmed that its implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.7 Fire Protection Program

Summary of Technical Information in the Application. LRA Section B.1.13 describes the existing Fire Protection Program as consistent with GALL AMP XI.M26, “Fire Protection,” with exception and enhancements.

The Fire Protection Program includes fire barrier, reactor coolant pump oil collection system, and diesel-driven fire pump inspections. The fire barrier inspection requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, and floors and periodic visual inspection and functional tests of fire rated-doors to maintain their operability. The diesel-driven fire pump inspection requires periodic testing and inspection of the pump and its driver so diesel engine subsystems, including the fuel supply line, can perform intended functions. The program periodically inspects and tests the Halon fire protection system (IP2) and the carbon dioxide fire protection system (IP3).

Staff Evaluation. During its audit and review, the staff confirmed the applicant’s claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Fire Protection Program to verify consistency with GALL AMP XI.M26. Details of the staff’s audit of the applicant’s AMP are documented in the Audit Report. As documented in the report, the staff found that the Fire Protection Program elements “preventive actions,” and “monitoring and trending,” are consistent with the corresponding elements in GALL AMP XI.M26. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the exception and enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited.

The GALL Report recommends that visual inspection of approximately 10 percent of each type of fire barrier penetration seal be performed during walkdowns carried out at least once every refueling outage. These inspections examine any sign of degradation such as cracking, seal separation from wall and components, separation of layers of material, rupture and puncture of seals, which are directly caused by increased hardness, and shrinkage of seal material due to weathering.

In RAI 3.0.3.2.7-1, dated February 13, 2008, the staff noted that LRA Table 2.4-4 lists fire stops and fire wrap as bulk commodities that perform an intended function as fire barriers. LRA Table 3.5.2-4, ‘Bulk Commodities,” identifies the material, environment and aging effect requiring aging management for these two commodities. The Fire Protection Program is identified in the AMR, along with Note J, which indicates that neither the component nor the material and environment combination is evaluated in the GALL Report. However, in LRA Section B.1.13, “Fire Protection,” there is no indication that fire stops and fire wraps are included as commodities whose aging effects will be managed by the AMP. The staff requested that the applicant describe how the aging effects of cracking/delamination, separation (for fire stops), and loss of material (for fire wrap) will be managed under the Fire Protection AMP.

In its response, dated March 12, 2008, the applicant stated that in LRA Section B.1.13, the fire protection program is an existing program that includes fire barrier inspections. The commodities fire stops and fire wraps are considered to be fire barriers which are included in the scope of the Fire Protection Program. Each fire stop (penetration seal) is visually inspected for cracking, delaminating, separation, and change in material properties at least once every seven operating cycles (15 percent every 24 months). Fire wraps are visually inspected at least once every 24 months for loss of material and any other indications of degradation or damage.

The GALL Report program states that approximately 10% of each type of penetration seal should be visually inspected at least once every refueling outage. The applicant indicated that the inspection program also requires that fire wraps be visually inspected at least once every 24 months for loss of material and any other indications of degradation or damage. The staff evaluated the applicant's program and determined that overall it meets or exceeds the penetration seal inspection frequency recommended in the GALL Report. The staff finds the fire stop and fire wrap inspection program acceptable, because it monitors material cracking, delaminating, separation, and change in fire stop and fire wrap properties.

Based on the applicant's response to RAI 3.0.3.2.7-1, dated March 12, 2008, the staff issued a follow up RAI 3.0.3.2.7-2 concerning inspection of inaccessible fire barrier penetration seals.

During an audit, the staff reviewed bases documents (for IP3) associated with the fire protection AMP. One of the bases documents states that 15 percent of the fire seals located in fire barriers are demonstrated to be operable by visual inspection on a frequency of 24 months. However, for those penetration seals that are inaccessible, the frequency of inspection is given as "not required." By letter dated April 29, 2008, the staff requested that the applicant justify the lack of visual inspections of inaccessible penetration seals.

In its response, dated May 28, 2008, the applicant stated that as provided in response to RAI 3.0.3.2.7-1, penetration seals are inspected at least once every seven operating cycles. However, IP3 site surveillance procedure provides provisions for cases where a penetration seal may become inaccessible for periodic inspection as result of plant configuration changes (i.e., installation of new plant equipment, walls, barriers, or other obstacles). In such cases, the IP3 site procedure includes guidance for the cessation of periodic surveillance of such penetration seals, subject to preparation of a formal fire protection engineering evaluation justifying the discontinuance of periodic visual surveillance.

As stated in the IP3 bases document, the visual inspection of inaccessible penetration seals is "not required" if justified by a supporting fire protection engineering evaluation, developed in accordance with the guidance of GL 86-10. On a case-by-case basis, the inaccessibility of any such penetration seal must be justified, and the fire protection adequacy of the configuration must be demonstrated. The evaluation, as stated in the bases document, must include assessment of proximate combustible loading, mitigating features, and the consequences of potential failure of the affected seal.

The applicant further stated that if the formal fire protection engineering evaluation (prepared in accordance with guidance of GL 86-10) demonstrates that the penetration seal is inaccessible for inspection, that the fire challenge to the barrier is insubstantial, and the consequences of failure of the seal would not compromise fire safety or nuclear safety, then periodic surveillance of that specific seal is not required.

The applicant clarified in the above response that the IP3 fire barrier penetration seal surveillance procedure includes inspection provisions for inaccessible fire barrier penetration seals based on a change in plant fire area configuration. The applicant stated that, for a plant change, an engineering evaluation based on guidance provided in GL 86-10[5] must be conducted to evaluate fire area configuration and to declare if a fire barrier penetration seal is inaccessible for periodic inspection.

The staff reviewed the applicant's response and found that it did not address the fact that GL 86-10 evaluations exist for all inaccessible fire barrier penetration seals; the response only indicated that it is a part of the fire protection program to perform such analysis. The staff requested the applicant to confirm that these analyses do exist and are periodically reviewed/updated to ensure their continued applicability. This was identified as Open Item 3.0.3.2.7-1.

By the letter dated January 27, 2009, the applicant stated that there are no IP3 fire barrier penetration seals excluded from periodic inspection due to inaccessibility. Therefore, there are no corresponding engineering evaluations.

The applicant clarified the IP3 fire barrier penetration seal program does not exclude periodic inspection of any inaccessible seal. The staff concludes that the concerns identified in Open Item 3.0.3.2.7-1 have been resolved. Therefore, Open Item 3.0.3.2.7-1 is closed.

Exception. In the LRA, the applicant took the following exception to the GALL Report program element “detection of aging effects”:

> The NUREG-1801 program recommends that testing and inspection of the Halon (IP2) and CO_2 (IP3) fire suppression systems occur at least once every six months. However, IPEC performs inspection every six months, functional testing is performed every 18 months for Halon 1301 and 24 months for CO_2.

During the audit and review, the staff asked the applicant to provide technical justification why the proposed testing frequency is acceptable to detect degradation of the Halon 1301 and CO_2 fire suppression systems before the loss of the components’ intended function (Audit Item 150).

In its response, dated March 24, 2008, the applicant stated that a review of past performance functional testing of Halon 1301 and CO_2 fire suppression systems has indicated no adverse material degradation that requires adjustment of the testing frequencies reported in the condition reporting database. This condition reporting database was similarly reviewed and revealed no indication of adverse material degradation.

The 18-month functional test frequency for the Halon 1301 and 24 months for CO_2 fire suppression systems is part of the current licensing basis documented in NRC IP2 SER dated October 31, 1980, and NRC IP3 SER dated April 20, 1994. The review of IP2 and IP3 operating experience indicated that these frequencies are reasonable to manage the aging effects. The functional testing frequencies are considered sufficient to ensure system availability and operability based on the plant operating history, and that there has been no aging-related event that has adversely affected system operation. Because these aging effects occur over a considerable period of time, the staff concluded that the 18-month and 24-month intervals will

[5] GL 86-10 is the means by which a licensee may make changes to the approved fire protection program without prior approval of the Commission in accordance with the standard license condition provided that the changes do not adversely affect the plant’s ability to achieve and maintain post-fire safe-shutdown.

be sufficient to detect aging of the Halon 1301 and CO_2 fire suppression systems.

The Halon 1301 and CO_2 fire suppression systems and associated components (bolting, coil, nozzles, piping and supports, tubing, fittings, valves, and tanks) are in an inside air (external) environment. The staff found that the applicant has demonstrated that the effects of aging on the Halon 1301 and CO_2 fire suppression systems will be adequately managed so that the intended functions will be maintained consistent with the current licensing basis for the period of extended operation, as required by 10 CFR 54.21(a)(3).

In addition, the staff noted that the applicant currently performs fire damper operational tests once per 12 months to detect degradation of the fire dampers before loss of the intended function. IP2 and IP3 maintenance procedures also include visual inspections of component external surfaces for signs of corrosion and mechanical damage every 6 months. The applicant's review of station operating experience identified no aging-related degradation adversely affecting the operation of the Halon 1301 and CO_2 fire suppression systems.

Although the Halon 1301 and CO_2 fire suppression system frequencies of functional testing exceed that recommended in GALL AMP XI.M26, the staff determined that it is sufficient to ensure system availability and operability with the existing surveillance which includes visual inspections of component external surfaces for signs of corrosion and mechanical damage, and verification of Halon 1301 and CO_2 storage tank weight, level, and pressure. In addition, the staff's review of the station operating history indicates no aging-related events adversely affecting system operation exist at IP2 and IP3. Based on its review of the applicant's program and plant-specific operating experience, the staff finds that the 18- and 24-month testing/surveillance frequencies for the Halon and CO_2 fire suppression systems are adequate for aging management considerations. On this basis, the staff finds this exception acceptable. The staff is adequately assured that the aging effects on the Halon 1301 and CO_2 fire suppression systems will be considered appropriately during plant aging management activities and that they will continue to perform their applicable intended functions consistent with the current licensing basis for the period of extended operation.

Enhancement 1. In the LRA, the applicant committed to implement the following enhancement to program elements, "scope of program, "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria": "IP3: Revise appropriate procedures to inspect external surfaces of the RCP oil collection system for loss of material each refueling outage."

The staff determined that this enhancement is acceptable because, when the enhancement is implemented in Fire Protection Program elements "scope of program, "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria," will be consistent with the GALL AMP XI.M26 program. This enhancement will enable the monitoring of the RCP oil collection system and components through inspection, providing a detailed look at system material condition to ensure external surfaces are not experiencing loss of material. This will provide additional assurance that the effects of aging are adequately managed.

Enhancement 2. In the LRA, the applicant committed to implement the following enhancement to program elements, "parameters monitored or inspected, "detection of aging effects, and "acceptance criteria":

> Revise appropriate procedures to explicitly state that the diesel fire pump engine sub-systems (including the fuel supply line) shall be observed while the pump is

running. Acceptance criteria will be revised to verify that the diesel engine does not exhibit signs of degradation that could involve items such as fuel oil, lube oil, coolant, or exhaust while running.

The staff determined that this enhancement is acceptable because, when the enhancement is implemented in Fire protection program elements “parameters monitored or inspected, “detection of aging effects, and “acceptance criteria” will be consistent with the GALL AMP XI.M26 program. GALL AMP XI.M26, Element 3, states that the diesel fire pump is observed during performance tests for detection of any fuel supply line degradation. This enhancement is also acceptable for making the program consistent with GALL AMP XI.M26, element 6, which states that no corrosion is acceptable in the diesel-driven fire pump fuel supply line. The staff reviewed the applicant’s program procedures and confirmed that these elements are consistent with the GALL Report.

Enhancement 3. In the LRA, the applicant committed to implement the following enhancement to program elements, “parameters monitored or inspected,” “detection of aging effects,” and “acceptance criteria”: “[r]evise appropriate procedures to specify that diesel fire pump engine carbon steel exhaust components are inspected for evidence of corrosion or cracking at least once each operating cycle.”

The staff determined that this enhancement is acceptable because, when the enhancement is implemented in Fire protection program element “parameters monitored or inspected,” “detection of aging effects,” and “acceptance criteria,” will be consistent with the GALL AMP XI.M26. GALL AMP XI.M26, Element 3, states that “periodic tests are performed at least once every refueling outage, such as … sequential starting capability tests. This enhancement is also acceptable for making the program consistent with GALL AMP XI.M26, Element 6, which states that no corrosion is acceptable. The staff reviewed the applicant’s program procedures and confirmed that these elements are consistent with the GALL Report.

Enhancement 4. In the LRA, the applicant committed to implement the following enhancement to program elements, “detection of aging effects,” and “acceptance criteria”: “IP3: Revise appropriate procedures to visually inspect the cable spreading room, 480V switchgear room, and EDG room CO_2 fire suppression system for signs of degradation, such as corrosion and mechanical damage, at least once every 6 months.”

The staff determined that this enhancement is acceptable because, when the enhancement is implemented in Fire protection program element “Detection of Aging Effects,” “Acceptance Criteria” will be consistent with the GALL AMP XI.M26 program. GALL AMP XI.M26, Element 4, states that the visual inspections of the Halon/CO_2 fire suppression system detect any sign of added degradation, such as corrosion, mechanical damage, or damage to dampers. This enhancement is also acceptable for making the program consistent with GALL AMP XI.M26, Element 6, which states that no corrosion is acceptable in the Halon/CO_2 fire suppression system. The staff reviewed the applicant’s program procedures and confirmed that these elements are consistent with the GALL Report.

Operating Experience. LRA Section B.1.13 states that inspections of fire stops, fire barrier penetration seals, fire barrier walls, ceilings, and floors from 2001 through 2005 revealed signs of degradation: cracks, gaps, voids, holes, or missing material. Periodic surveillances in 2001 and 2004 detected discrepancies in fire barrier wrappings. Immediate actions repaired these fire barriers. Detection of deficiencies and timely corrective actions provide confidence that the program will continue to be managed to effectively identify and minimize any loss of component material.

LRA Section B.1.13 states that a program self-assessment in 2003 found deficiencies in the fire barrier inspection list at IP2. Corrective actions reviewed the Type I fire barrier drawing against the inspection list in the procedure and changed the procedure and drawing. Detection of program weaknesses and subsequent corrective actions assure continued program effectiveness in managing loss of component material.

LRA Section B.1.13 states that quality assurance audits in 2003, 2005, and 2006 revealed that the material condition of system equipment was good. The audits revealed no issues or findings that could impact program effectiveness in managing aging effects for fire protection components.

LRA Section B.1.13 states that a November 2005 inspection of the reactor coolant pump oil collection system within the IP2 containment building found no indications of loss of system component material.

Additionally, in November 2006, observations of the IP2 and IP3 diesel-driven fire pumps while they were running noted no leaks or degradation of diesel engine sub-systems, including the fuel supply line. The applicant stated that continuing monitoring provides confidence that the program effectively manages aging of diesel-driven fire pump subsystem components.

LRA Section B.1.13 states that in August 2004, the NRC completed a triennial fire protection team inspection at IP2 to assess whether the plant had implemented an adequate fire protection program and whether post-fire safe shutdown capabilities had been established and maintained properly. The inspection team also evaluated the material condition of fire area boundaries, fire doors, and fire dampers and reviewed the surveillance and functional test procedures for the diesel fire pump and other components. Additionally, the team reviewed the surveillance procedures for structural fire barriers, penetration seals, and structural steel and made no significant findings. Confirmation of program compliance with established standards and regulations assures continued program effectiveness in managing loss of component material.

LRA Section B.1.13 states that on May 17, 2007, the NRC completed a triennial fire protection team inspection at IP2 to assess whether the plant had implemented an adequate fire protection program and whether post-fire safe-shutdown capabilities had been established and maintained properly. The team walked down accessible portions of selected fire areas to observe material condition and the adequacy of design of fire area boundaries (including walls, fire doors and fire dampers) to ensure they were appropriate for the fire hazards in the area. The inspection team reviewed electric and diesel fire pump flow and pressure test results to ensure that the pumps were meeting their design requirements. The team reviewed the fire main loop flow test results to ensure that the flow distribution circuits were able to meet the design requirements. The team also performed a walkdown of accessible portions of the detection and suppressions systems in the selected areas as well as a walkdown of major system support equipment in other areas (e.g., fire protection pumps, Halon storage tanks and supply system) to assess the material condition of the systems and components. No findings of significance were identified.

LRA Section B.1.13 states that in January 2005, the NRC completed a triennial fire protection team inspection at IP3 to assess whether the plant had implemented an adequate fire protection program and whether post-fire safe-shutdown capabilities had been established and maintained properly. The inspection team evaluated the material condition of fire area boundaries, fire doors, and fire dampers, and reviewed the surveillance and functional test procedures for the diesel fire pump and other components. The staff also reviewed for adequacy of selected total flooding CO_2 systems and surveillance procedures for periodic system testing and the adequacy of structural fire barriers and penetration seals. The team made no significant findings. Confirmation of program compliance with established standards and regulations assures continued program effectiveness in managing aging effects.

The staff reviewed the above operating experience and also condition reports made available during the audit, and interviewed the applicant's technical staff. The staff confirmed that the plant-specific operating experience did not reveal any degradation not already bounded by industry experience. The staff also reviewed the IP2 and IP3 operating experience reports, condition reports, and maintenance work orders associated with the corrective actions taken for the identification of signs of degradation of fire protection components. The staff confirmed that the condition reports were closed out by repairs to the degraded fire barriers or by performing adequate engineering evaluations for their acceptability. The staff noted that the applicant performs periodic inspections and places identified deficiencies into their corrective action program to ensure appropriate corrective actions are performed in a timely manner.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.12 and A.3.1.12, the applicant provided the UFSAR supplement for the Fire Protection Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

As documented in LRA Sections A.2.1.12 and A.3.1.12, the applicant has committed to enhance this program prior to entering the period of extended operation (Commitment 7).

Conclusion. On the basis of its audit and review of the applicant's Fire Protection Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report, are consistent. In addition, the staff reviewed the exception and its justifications and determined that the program is adequate to manage the aging effects for which it is credited. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the current licensing basis for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.8 Fire Water System Program

Summary of Technical Information in the Application. LRA Section B.1.14 describes the existing Fire Water System Program as consistent with GALL AMP XI.M27, "Fire Water System," with exception and enhancements.

The Fire Water System Program manages water-based fire protection systems consisting of sprinklers, nozzles, fittings, valves, hydrants, hose stations, standpipes, piping, and components tested in accordance with National Fire Protection Association (NFPA) codes and standards to assure system functionality. Periodic flushing, system performance testing, and inspections determine whether significant corrosion has occurred in water-based fire protection systems. Many of these systems normally are maintained at required operating pressure and monitored to detect leakage resulting in loss of system pressure immediately for corrective actions. In addition, periodic wall thickness evaluations of fire protection piping on system components by nonintrusive techniques (e.g., volumetric testing) detect loss of material due to corrosion. Inspection of a sample of sprinkler heads required by 10 CFR 50.48 will be guided by NFPA 25 (2002 edition), Section 5.3.1.1.1. NFPA 25 states, “Where sprinklers have been in place for 50 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory for field service testing.” This sampling will be repeated every 10 years after initial field service testing.

Staff Evaluation. During its audit and review, the staff confirmed the applicant’s claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Fire Water System Program to verify consistency with GALL AMP XI.M27. Details of the staff’s audit of the applicant’s AMP are documented in the Audit Report. As documented in the report, the staff found that the Fire Water System Program elements “scope of program,” “preventive actions,” and “monitoring and trending,” are consistent with the corresponding elements in GALL AMP XI.M27. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the exception and enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited.

The staff asked the applicant to clarify why jockey pumps were excluded from the scope of the Fire Water System Program (Audit Item 152). By letter dated March 24, 2008, the applicant stated that the fire water jockey pumps support standby operation of the fire water system and are conservatively included in the scope of the license renewal and subject to an AMR. The Fire Water System Program manages component aging effects. However, the applicant stated that the jockey pumps are not required for operation of the fire water system to comply with 10 CFR 50.48 and Appendix R. The applicant also stated that testing of the jockey pumps is not required.

The staff reviewed the applicant’s response and finds it contrary to the IP3 fire protection SER dated March 6, 1979, which is part of the current licensing basis. That SER reflects the applicant’s commitment to implement modifications that conform to the provisions of Appendix A to BTP APCSB 9.5-1. Sections 3.1.5 and 4.3.1.2 of the SER dated March 6, 1979, state in part, “[t]wo 2500 gpm fire pumps, one electric motor driven and one diesel engine driven, will be provided along with two jockey pumps. . . . [t]wo electric jockey pumps [are] provided to maintain pressure on the fire water system . . .” The applicant indicated in the audit question response that the jockey pumps in question are within the scope of license renewal and subject to an AMR but are not required for operation of the fire water system to comply with 10 CFR 50.48 and Appendix R. The applicant’s current licensing basis demonstrates that this component was credited to meet the guidance of Appendix A to BTP APCSB 9.5-1. Therefore, the staff considers that the jockey pumps in question should be included within the scope of license renewal pursuant to 10 CFR 54.4(a)(3) because they are required for compliance with 10 CFR 50.48 . The staff agrees that testing is not required for the jockey pump. The staff notes that NFPA Fire Pump Handbook, 1st Edition, Section 2-19, Page 136, states that pressure maintenance devices are not required to be tested for fire protection service. Although the applicant disagrees with the staff's view that the jockey pumps are required for compliance with 10 CFR 50.48, the applicant has included the jockey pumps within the scope of license renewal, and they are subject to an AMR.

During its review, the staff noted that a "cross-connect" of the high pressure fire water system exists between Units 1, 2, and 3 individual fire water supply systems, and asked the applicant if credit has been taken for the use of this capability per the CLB (Audit Item 153). By letter dated March 24, 2008, the applicant clarified that IP2 and IP3 maintain independent fire protection systems and the "cross-connect" is not considered for compliance with IP2 and IP3 fire protection requirements. The IP3 UFSAR states that the IP3 fire protection system was originally designed as an extension of the IP1 fire protection system. After a series of modifications, the IP3 fire protection was made to be independent from the IP1 fire protection system. The staff finds the applicant's response acceptable because it clarified that the cross-connection between units is not credited for compliance with fire protection requirements, and thus, is not subject to an AMR.

Exception. In the LRA, the applicant took the following exception to the GALL Report program element "detection of aging effects":

> NUREG-1801 specifies annual fire hose hydrostatic and gasket inspections. Fire hoses and hose station gaskets are not subject to an AMR and not included in the program.[1]
>
> [1]Fire hoses are periodically inspected, hydrostatically tested, and replaced as required in accordance with plant procedures. Gaskets in couplings are replaced during hose station inspections.

As stated in the footnote, the applicant periodically inspects and replaces hoses and hose gaskets; therefore, they are not subject to an AMR. The applicant treats these components as consumables. The staff determined that, since hose gaskets are replaced on a periodic basis, this meets the guidance in SRP-LR Section 2.1.3.2.2.

The staff recognizes that the applicant's interpretation of these items as consumables (short-lived components) will result in more vigorous oversight of the condition and performance of the component. Therefore, the staff is adequately assured that fire hoses and hose station gaskets used for the fire suppression will be considered appropriately during the period of extended operation.

Enhancement 1. In the LRA, the applicant committed to implement the following enhancement to program elements "parameters monitored or inspected" and "acceptance criteria": "[r]evise applicable procedures to include inspection of hose reels for corrosion. Acceptance criteria will be revised to verify no unacceptable sign of degradation."

The staff determined that this enhancement is acceptable because, when the enhancement is implemented in Fire Water System Program element "parameters monitored or inspected" and "acceptance criteria," will be consistent with the GALL AMP XI.M27 program. The staff reviewed the applicant's program procedures to confirm that these elements are consistent with the GALL Report. The staff is adequately assured that this enhancement will adequately manage the effects of aging.

Enhancement 2. In the LRA, the applicant committed to implement the following enhancement to program elements “parameters monitored or inspected,” “detection of aging effects,” and “acceptance criteria”: “IP3: Revise applicable procedures to inspect the internal surface of the foam-based fire suppression tanks. Acceptance criteria will be enhanced to verify no significant corrosion.” By letter dated January 17, 2008, the applicant revised this enhancement to remove the reference to IP3. This enhancement now applies to both IP2 and IP3.

The staff determined that this enhancement is acceptable because, when the enhancement is implemented in Fire Water System Program elements “parameters monitored or inspected,” “detection of aging effects,” and “acceptance criteria,” will be consistent with the GALL AMP XI.M27 program. The staff reviewed the applicant’s program procedures to confirm that these elements are consistent with the GALL Report. The staff is adequately assured that this enhancement will adequately manage the effects of aging.

Enhancement 3. In the LRA, the applicant committed to implement the following enhancement to program element “detection of aging effects”:

> A sample of sprinkler heads for fire water systems required for 10 CFR 50.48 will be inspected using guidance of NFPA 25 (2002 Edition), Section 5.3.1.1.1, before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion are detected in a timely manner.

The staff determined that this enhancement is acceptable because, when the enhancement is implemented, Fire Water System Program element “detection of aging effects,” will be consistent with GALL AMP XI.M27 which states that the sprinkler heads are inspected before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner.

Enhancement 4. In the LRA, the applicant committed to implement the following enhancement to program element “detection of aging effects”:

> Wall thickness evaluations of fire protection piping will be performed on system components using non-intrusive techniques (e.g., volumetric testing) to identify loss of material due to corrosion. These inspections will be performed before the end of the current operating term and at intervals thereafter during the period of extended operation. Results of the initial evaluations will be used to determine the appropriate inspection interval to ensure aging effects are identified prior to loss of intended function.

The staff determined that this enhancement is acceptable because, when the enhancement is implemented, Fire Water System Program element “detection of aging effects,” will be consistent with GALL AMP XI.M27 which states that wall thickness evaluations of fire protection piping are performed on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion. These inspections are performed before the end of the current operating term and at plant-specific intervals thereafter during the period of extended operation. As an alternative to non-intrusive testing, the plant maintenance process may include a visual inspection of the internal surface of the fire protection piping upon each entry into the system for routine or corrective maintenance, as long as it can be demonstrated that inspections are performed (based on past maintenance history) on a representative number of locations on a reasonable basis.

Operating Experience. In addition to the operating experience cited in LRA Section B.1.13, LRA Section B.1.14 stated that visual inspections of fire hose station equipment in September 2005 at IP3 and in November 2006 at IP2 revealed no loss of material on hose station steel parts. One broken sprinkler nozzle was replaced as a result of the IP2 inspection. Detection of degradation followed by corrective action prior to loss of intended function provides confidence that the program will continue to effectively manages aging effects for steel fire water system components.

Further, LRA Section B.1.14 states that flow tests of fire main segments and hydrant inspections during 2006 found no evidence of obstruction or loss of material. Spray and sprinkler system functional tests and visual inspections of piping and nozzles in 2006 found no evidence of blockage or loss of material. Confirmed absence of degradation provides confidence that the program will continue to effectively manage loss of material for fire water system components.

The staff reviewed the above operating experience and also operating experience reports and interviewed the applicant's technical staff and confirmed that the plant-specific operating experience did not reveal any degradation not already bounded by industry experience. The staff also reviewed the IP2 and IP3 operating experience reports, condition reports, and maintenance work orders associated with the corrective actions taken for the identification of signs of degradation of fire protection components. The staff confirmed that the condition reports were closed out by repairs to the degraded fire barriers or performed engineering evaluations for their acceptability. The staff noted that the applicant performs periodic inspections and places identified deficiencies into their corrective action program to ensure appropriate corrective actions are performed in a timely manner.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.13 and A.3.1.13, the applicant provided the UFSAR supplement for the Fire Water System Program. By letter dated December 18, 2007, the applicant revised LRA Section A.2.1.13 to state that "sprinkler heads required for 10 CFR 50.48 will be replaced or a sample tested using guidance of NFPA 25 (2002 edition)." By letter dated January 17, 2008, the applicant revised LRA Section A.2.1.13 to add the following "revise applicable procedures to inspect the internal surface of the foam-based fire suppression tanks." The staff reviewed these sections, as revised, and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

As documented in LRA Sections A.2.1.13 and A.3.1.13, the applicant has committed to implement the enhancements prior to entering the period of extended operation (Commitment 8).

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 exception and its justifications and determined that the program s adequate to manage the aging effects for which it is credited. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the current licensing basis for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Flux Thimble Tube Inspection Program

<u>Summary of Technical Information in the Application</u>. LRA Section B.1.16 describes the existing Flux Thimble Tube Inspection Program as consistent with GALL AMP XI.M37, “Flux Thimble Tube Inspection,” with enhancements.

LRA Section B.1.16 states that the Flux Thimble Tube Inspection Program monitors thinning of the flux thimble tube wall, a path for the in-core neutron flux monitoring system detectors and part of the reactor coolant system pressure boundary. Flux thimble tubes are subject to loss of material at certain locations in the reactor vessel where flow-induced fretting causes wear at discontinuities in the path from the reactor vessel instrument nozzle to the fuel assembly instrument guide tube. A nondestructive examination (NDE) methodology, eddy current testing or other similar inspection method, monitors for wear of the flux thimble tubes. This program implements the recommendations of NRC Bulletin 88-09, “Thimble Tube Thinning in Westinghouse Reactors.”

<u>Staff Evaluation</u>. During its audit and review, the staff confirmed the applicant’s claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Flux Thimble Tube Inspection Program to verify consistency with GALL AMP XI.M37. Details of the staff’s audit of the applicant’s AMP are documented in the Audit Report. As documented in the report, the staff found that the Flux Thimble Tube Inspection Program elements “scope of program,” “preventive actions,” “parameters monitored or inspected,” and “detection of aging effects,” are consistent with the corresponding elements in GALL AMP XI.M37. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited.

<u>*Enhancement 1.*</u> In the LRA, the applicant committed to implement the following enhancement to program element “monitoring and trending”: _“[r]evise appropriate procedures to implement comparisons to wear rates identified in WCAP-12866. Include provisions to compare data to the previous performances and perform evaluations regarding change to test frequency and scope.”

The staff verified that the applicant included this enhancement in Commitment 9. The “monitoring and trending” program element in GALL AMP XI.M37 recommends that the wear rate projections for flux thimble tubes be based on plant-specific wear data. The staff finds that this enhancement will make the “monitoring and trending” program element in the Flux Thimble

Tube Program consistent with the corresponding program element in GALL AMP XI.M37. The staff finds that this is acceptable because the applicant will use the plant-specific wear data to adjust the projected wear values and inspection frequencies if it is determined that the wear rates from the plant specific data are more conservative than the generic wear rate that is recommended in WCAP-12866, "Bottom-Mounted Instrumentation Flux Thimble Wear," January 1991. Thus, the applicant will only use the generic wear rate value if it remains conservative relative to wear rates that are established from the plant-specific data.

Enhancement 2. In the LRA, the applicant committed to implement the following enhancement to program element "acceptance criteria": "[r]evise appropriate procedures to specify the acceptance criteria as outlined in WCAP-12866 or other plant-specific values based on evaluation of previous test results."

The staff verified that the applicant included this enhancement in Commitment 9. In the "acceptance criteria" program element in GALL AMP XI.M37, the staff established the following recommended criteria for acceptance criteria that are used to evaluate flux thimble tube to wear:

> Appropriate acceptance criteria such as percent through-wall wear will be established. The acceptance criteria will be technically justified to provide an adequate margin of safety to ensure that the integrity of the reactor coolant system pressure boundary is maintained. The acceptance criteria will include allowances for factors such as instrument uncertainty, uncertainties in wear scar geometry, and other potential inaccuracies, as applicable, to the inspection methodology chosen for use in the program. Acceptance criteria different from those previously documented in NRC acceptance letters for the applicant's response to Bulletin 88-09 and amendments thereto should be justified.

In response to the NRC Bulletin 88-09 in April 1989, the staff verified that Entergy originally committed to an acceptance criterion of 50 percent allowable throughwall wear in wall thickness of the thimble tubes at IP2 and 60 percent allowable throughwall wear for the corresponding thimble tubes at IP3. However, WCAP-12866[6], established that a thimble tube can safely operate with up to 80 percent through wall loss, even with considerations of all uncertainties that may occur during an ECT. The staff noted, however, that since 1991, Entergy has used Westinghouse's 80 percent allowable throughwall wear (i.e., a 20 percent minimum wall thickness criterion) as its basis for accepting wear projections prior to the next scheduled outage for the thimble tube examinations.

The staff also noted that Entergy's current program calls for Entergy to perform the ECT examinations of the IP2 and IP3 thimble tubes at scheduled inspection intervals and to record

[6] Westinghouse WCAP-12866 is a Class 2 Proprietary Westinghouse Report. In NRC Bulletin 88-09, the staff specifically stated, in part, that "each addressee is requested to establish an inspection program to monitor thimble tube performance that includes the establishment, with technical justification, of an appropriate thimble tube wear acceptance criterion."

The 80 percent allowable through-wall wear acceptance criterion established in the report is not considered by the NRC to be proprietary in content because the staff did not intend this type of information to be withheld from the public when it issued NRC Bulletin 88-09. Further, this type of information has been divulged to the general public in the past in other industry correspondence, NRC correspondence, NRC audit reports, and safety evaluations. However, the remaining specific data, equations, and information are considered to be proprietary in content and are withheld from the public, in accordance 10 CFR 2.390. Therefore, only a general basis on the acceptability of Westinghouse's 80 percent through-wall wear acceptance criterion will be given in this SER.

the wall thickness measurements for the thimble. The staff also noted that the applicant's program then calls for Entergy to: (1) use its plant specific wear rate data to project the remaining thimble wall thickness at the next schedule outage in which thimble tube examinations are performed, and (2) compare the projected wall thicknesses to the 20 percent allowable minimum wall thickness criterion that is being relied upon for programmatic acceptance on allowable wear.

The staff has previously accepted the 80 percent allowable throughwall wear acceptance value in the WCAP-12866 because the acceptance criterion was based on conservative burst tests on Westinghouse thimble tube designs that supported this acceptance criterion for the thimble tubes in Westinghouse designed nuclear plants, including IP2 and IP3. The staff also accepted this value because the acceptance criterion includes an additional safety margin on allowable wear in Westinghouse-designed thimble tubes.[6]

The applicant's enhancement of the program will ensure that the acceptance criteria used for the program is proceduralized and justified. The staff has approved the 80 percent allowable throughwall wear acceptance criterion in WCAP-12866 for use because the applicant may justify an acceptance criterion different from this value based on the results of IP2 or IP3 specific wear rate data. Based on this review, the staff finds that this enhancement will make the "acceptance criteria" program element in the Flux Thimble Tube Program consistent with the corresponding program element in GALL AMP XI.M37 and that the enhancement is acceptable.

Enhancement 3. In the LRA, the applicant committed to implement the following enhancement to program element "acceptance criteria":

> Revise appropriate procedures to direct evaluation and performance of corrective actions based on tubes that exceed or are projected to exceed the acceptance criteria. Also stipulate in procedures that flux thimble tubes that cannot be inspected over the tube length and can not be shown by analysis to be satisfactory for continued service, must be removed from service to ensure the integrity of the reactor coolant system pressure boundary.

The staff verified that the applicant included this enhancement Commitment 9. In the "corrective actions" program element in GALL AMP XI.M37, the staff established its recommendation that flux thimble tubes out of conformance with the established minimum thimble tube wall thickness acceptable criterion must be either "isolated, capped, plugged, withdrawn, replaced, or otherwise removed from service in a manner that ensures the integrity of the reactor coolant system pressure boundary," and that thimble tubes approaching this acceptance criterion may be "repositioned." The staff also established that "flux thimble tubes that cannot be inspected over the tube length, that ... [are] ... subject to wear due to restriction or other defect, and that can not be shown by analysis to be satisfactory for continued service, must be removed from service to ensure the integrity of the reactor coolant system pressure boundary."

The staff noted that based on the applicant's use of appropriate Westinghouse documents, the applicant isolates, caps, plugs, withdraws, repositions, or replaces thimble tubes whose wall thicknesses are projected to be less than the minimum wall thickness of 20 percent at the next inspection outage. The staff also noted that the applicant's enhancement of the "corrective actions" program element will incorporate these corrective action criteria. Thus, based on this review, the staff finds that this enhancement will make the "corrective actions" program element in the Flux Thimble Tube Program consistent with the corresponding program element in GALL

AMP XI.M37 and that the enhancement is acceptable.

Based on this review, the staff finds that the Flux Thimble Tube Inspection Program, as enhanced by the applicant, is either in conformance with the recommended criteria in GALL AMP XI.M37, or that the enhancements will ensure that use of the generic wear rate and acceptance criterion in WCAP-12866 will be conservative and justified.

Operating Experience. LRA Section B.1.16 states that after flux thimble tube inspections at IP2 in March 1989, an inspection plan used the inspection results and WCAP-12866 methodology.

The applicant's operating experience discussion states that, after flux thimble tube inspections at IP3 in May 1997 and May 2001, a comparison of 1997 to 2001 results for each tube indicating wall loss revealed, in general, that tubes had either no significant increase in wall loss or an increase of 20 percent or less over four years. The applicant's operating experience discussion also indicated that all 2001 recorded wall losses were below the maximum allowed by the WCAP-12866 vendor guidelines and that detection of degradation prior to loss of function indicates that the program is effective in managing loss of material due to wear in these components.

The staff reviewed the "operating experience" program element in the applicant's license renewal basis document for this program but did not find any additional summary details beyond what was originally included and discussed in LRA AMP B.1.16. However, the staff reviewed one ECT test report each for IP2 and IP3 and verified that the ECT test reports confirmed Entergy's claim that it was already periodically performing eddy current inspections of both IP2 and IP3 flux thimble tubes in accordance with the Bulletin 88-09 recommendations.

The staff also verified that, in the spring 2006 IP2 outage, Entergy repositioned all flux thimbles as part of a seal table modification, except for nine thimble tubes that the applicant capped as a more conservative corrective action. The staff verified that Entergy has capped two IP3 thimble tubes based on plant-specific IP3 calculations.

In RAI RCS-2, the staff asked the applicant, in part, to clarify how it performed a condition report review for relevant operating experience related to implementation of this program. The applicant provided its response to RAI RCS-2 in Entergy letter dated June 5, 2008. In this response, the applicant clarified that, with respect to operating experience that is applicable to the Flux Thimble Tube Inspection Program, the applicant took the following two-tiered approach to determine whether there was any applicable operating experience related to the reactor vessel flux thimble tubes at IP2 and IP3:

(1) The applicant conducted interviews of the applicable site program owners at IP2 and IP3 to discuss: (1) program effectiveness, (2) site-specific of generic bases for making any programmatic changes to the program elements of the program, (3) aspects of the program that would demonstrate successful implementation and performance of the program, (4) aspects of the programs that would demonstrate programmatic strengths and weaknesses in the program, and (5) the results of any QA audits, self assessments, or peer review evaluations that were performed on the program

(2) The applicant conducted searches to locate and review applicable inspections, test, and examinations reports for the thimble tubes in order to determine whether the inspections, examinations, or tests had indicated any evidence of aging effects in the thimble tubes.

> The applicant also conducted applicable keyword searches of its condition report (CR) database in order to locate any IP2 and IP3 flux thimble tubes issues and to ensure that any CRs generated as a result of this search were evaluated and retained for further evaluation of the program.

The applicant stated that inspection results for these components were located in applicable thimble inspection reports, QA surveillance records, and assessment findings. The applicant also stated that the results of these program owner interviews and document searches were documented in the IP "Operating Experience Review Report." The staff noted that the applicant's response to RAI RCS-2 indicated that the applicant had performed an extensive enough review to search for and locate reports or documentation that would provide evidence of age-related aging effects in the IP2 or IP3 flux thimble tubes. Thus, based on the response to RAI RCS-2, as made relative to the Flux Thimble Program, and on the applicant's corrective actions of capping or repositioning to address adverse conditions of thimble tube wear, the staff concludes that the applicant has performed a sufficient review for relative operating experience related to flux thimble tube degradation and that the applicant has provided acceptable evidence that appropriate corrective actions are taken when adverse aging related to thimble tube wear is detected in the components. RAI RCS-2 is resolved with respect to the adequacy of operating experience reviews and corrective actions for flux thimble tubes at IP2 and IP3.

Based on this review, the staff finds that the applicant has been performing its ECT examinations of the IP2 and IP3 thimble tubes to address the experience discussed in NRC Bulletin 88-09 and that Entergy has been taking appropriate corrective action prior to the time when the thimble tube wear is projected to exceeding the applicant acceptance criterion for the program.

Based on this review, the staff confirms that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

<u>UFSAR Supplement</u>. In LRA Sections A.2.1.15 and A.3.1.15, the applicant provided the UFSAR supplement for the Flux Thimble Tube Inspection Program. The staff reviewed these UFSAR Supplement sections and Commitment No. 9 on the LRA. The staff verified that the UFSAR Supplement summary descriptions in LRA Section A.2.1.15 and A.3.1.15 incorporated the type of elements that are provided in the staff's recommended summary report description for these type of programs, as given in Table 3.1-2 of the SRP-LR. The staff also verified that Commitment 9 of the LRA references that the commitment is applicable to these UFSAR Supplement sections. Based on the review, the staff finds that the information in the UFSAR supplement provides an adequate summary description of the program and meets the requirement in 10 CFR 54.21(d) because the summary descriptions have incorporated the type of element descriptions that are recommended for these type of programs in the SRP-LR and because the UFSAR Supplement summary descriptions appropriately reflect Commitment 9 on the LRA.

<u>Conclusion</u>. On the basis of its audit and review of the applicant's Flux Thimble Tube Inspection Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately

managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Masonry Wall Program

Summary of Technical Information in the Application. LRA Section B.1.19 describes the existing Masonry Wall Program as consistent with GALL AMP XI.S5, "Masonry Wall Program," with enhancement.

The Masonry Wall Program manages aging effects so the evaluation basis established for each masonry wall within the scope of license renewal remains valid through the period of extended operation. The program visually inspects all masonry walls with 10 CFR 54.4 intended functions. Included components are 10 CFR 50.48-required masonry walls, radiation shielding masonry walls, and masonry walls with the potential to affect safety-related components. Structural steel components of masonry walls are managed by the Structures Monitoring Program. Visual examinations of masonry walls are at a frequency to ensure no loss of intended function between inspections.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Masonry Wall Program to verify consistency with GALL AMP XI.S5. Details of the staff's audit of the applicant's AMP are documented in the Audit Report. As documented in the report, the staff found that the Masonry Wall Program elements "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria," are consistent with the corresponding elements in GALL AMP XI.S5. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

As documented in the Audit Report, the staff reviewed the program basis documents and confirmed that the Masonry Wall Program is an existing program that manages aging effects for all masonry walls identified as performing intended functions in accordance with 10 CFR 54.4. The existing program is the Condition Monitoring of Maintenance Rule Structures which is a program that establishes the requirements for monitoring the various structures at IP2 and IP3 in accordance with 10 CFR 50.65.

The staff reviewed the enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited.

Enhancement. In the LRA, the applicant committed to implement the following enhancement to the program element "scope of program": "[r]evise applicable procedures to specify that the IP1 intake structure is included in the program."

During an audit, the staff asked the applicant if a documented seismic qualification basis, in accordance with IE Bulletin 80-11, has been developed for the masonry components of the 1P1 intake structure (Audit Item 62). By letter dated March 24, 2008, the applicant stated that there are no masonry walls in the IP1 intake structure which meet the criteria for inclusion in the site-specific IE Bulletin 80-11 program. Therefore, no seismic qualification basis in accordance with IE Bulletin 80-11 has been developed for masonry walls of the IP1 intake structure. The masonry walls in the IP1 intake structure were included in the Masonry Wall AMP because the IP1 intake structure houses components required for the alternate safe shutdown system, which is credited in the Appendix R safe shutdown analysis. The staff finds that including the masonry walls, located within the IP1 intake structure, in the Masonry Wall Program is acceptable since it provides support for equipment that perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48).

The staff reviewed the proposed enhancement and finds it acceptable because implementation of the enhancement will result in the inclusion of the IP1 intake structure identified by the applicant as within the scope of license renewal in accordance with 10 CFR 54.4(a), which is consistent with the GALL Report.

<u>Operating Experience</u>. LRA Section B.1.19 identifies the following inspection results for masonry walls:

Inspections of the IP2 fan house in 2001 detected cracking and spalling in some walls. These conditions did not affect their structural integrity and were repaired. Slight corrosion of column-to-wall connections did not affect their structural integrity, and was listed for future monitoring.

Inspections of the IP2 fuel storage building in 2003 detected some hairline cracks and loose blocks which were listed for future monitoring.

Inspections of the IP2 control building in 2003 found evidence of water intrusion only in efflorescence on the concrete floor. This condition did not affect the structural integrity of the walls.

Inspections of the IP3 primary auxiliary building, fuel storage building, fan house, and turbine building in 2003 through 2005 noted minor cracking in some walls unchanged from the baseline condition and some leaking seals, which were repaired. A crack in the joint between the fuel storage building and the fan house was noted as acceptable with future monitoring.

Inspections of the city water metering house in 2004 detected some hairline cracks and loose blocks found acceptable but listed for future monitoring.

Inspections of the IP2 turbine building in 2004 detected minor cracks and spalling, which did not affect structural integrity, and were listed for future monitoring.

Inspections of the IP3 control building in 2005 revealed hairline cracks in the battery room walls found acceptable with no effect on structural integrity. These cracks did not require future monitoring.

Inspections of the IP3 fan house in 2006 detected hairline cracks which did not affect the structural integrity of the walls and were listed for future monitoring.

Inspections of the IP3 fuel storage building in 2006 detected minor shrinkage cracking along the mortar joints on the outside of the south wall with no observable change in width since the baseline inspection. These conditions did not affect the structural integrity of the walls.

The applicant concluded that detection of degradation followed by corrective action prior to loss of intended function prove that the program effectively manages cracking of masonry walls and masonry wall joints.

The staff reviewed the program basis document discussion of operating experience. This report discussed the results of past visual examinations of masonry walls at IP2 and IP3. It cites examples of degradation of some masonry walls that occurred in the past and how they were disposition. In some cases hairline cracks were identified and found not to affect structural integrity and in other cases cracks and loose blocks were identified and found not to affect structural integrity, however, they were repaired.

The staff confirmed that the “operating experience” program element satisfies the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.18 and A.3.1.18, the applicant provided the UFSAR supplement for the Masonry Wall Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

The applicant has committed to implement the enhancement prior to entering the period of extended operation (Commitment 12).

Conclusion. On the basis of its audit and review of the applicant’s Masonry Wall Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report, are consistent. Also, the staff reviewed the enhancement regarding the scope of program element and confirmed that its implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Metal-Enclosed Bus Inspection Program

Summary of Technical Information in the Application. LRA Section B.1.20 describes the existing Metal-Enclosed Bus (MEB) Inspection Program as consistent with the GALL Report AMP XI.E4, “Metal Enclosed Bus,” with exceptions and enhancements.

The existing Metal-Enclosed Bus Inspection Program inspects the following non-segregated phase buses:

- IP2/IP3 - 6.9kV bus between station aux transformers and switchgear buses 1/2/3/4/5/6
- IP3 - 6.9kV bus for the gas turbine substation
- IP2 - 480V bus for substation A
- IP2/IP3 - 480V bus between EDGs and switchgear buses 2A/3A/5A/6A

The applicant stated that inspections are for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. Inspection of bus insulation is for signs of embrittlement, cracking, melting, swelling, or discoloration which may indicate overheating or aging degradation. The applicant further stated that inspection of internal bus supports is for structural integrity and signs of cracks. Bolted connections are covered with heat-shrink tape or insulating boots per manufacturer recommendations, so a sample of accessible bolted connections is inspected visually for insulation material surface anomalies. Enclosure assemblies are inspected visually for evidence of loss of material.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Metal Enclosed Bus Inspection Program and basis documents for consistency with GALL AMP XI.E4. Details of the staff's audit of this AMP are documented in the Audit Report. As documented in the report, the staff found that the Metal Enclosed Bus Program elements "preventive actions," and "monitoring and trending" are consistent with respective elements in GALL AMP XI.E4. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the exceptions and their justifications to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff also reviewed the enhancements to determine whether the program will be consistent with the GALL Report AMP XI.E4.

Exception 1. In the LRA, the applicant took the following exception to the GALL Report element "parameters monitored or inspected": "NUREG-1801 specifies this program provides for the inspection of the internal portion of the MEBs. The IPEC program specifies visual inspection of the external surfaces of the MEB enclosure assemblies in addition to internal portions."

Exception 2. In the LRA, the applicant took the following exception to the GALL Report element, "detection of aging effects": "NUREG-1801 specifies this program provides for the inspection of the internal portion of the MEBs. IPEC inspects the MEB enclosure assemblies externally in addition to internal surfaces."

For both exceptions, the applicant stated under Note 1, that "Inspection of the external portion of MEB enclosure assemblies under the Metal-Enclosed Bus Inspection Program assures that effects of aging will be identified prior to loss of intended function. Visual inspections have been proven effective in detecting indications of loss of material."

The GALL Report, Items VI.A-12 and VI-13, refer to the Structure Monitoring Program for inspecting the external of MEB for loss of material due to general corrosion and inspecting the enclosure seals for hardening and loss of strength due to elastomer degradation. In LRA Section B.1.20, the applicant stated that the program attribute of MEB inspection program would be consistent with the program attribute in the GALL Report, Section XI.E4 with an exception. The exception is to inspect MEB enclosure assemblies in addition to internal surfaces using the MEB inspection program. The staff found the exception acceptable because the external of MEBs will be inspected in the MEB Inspection program instead of a separate GALL Structure Monitoring Program. These inspections are the same as those in GALL Structure Monitoring Program.

Enhancement 1. In the LRA, the applicant committed to implement the following enhancement to program element, "scope of program": "[r]evise appropriate procedures to add IP2 480 V bus associated with substation A to the scope of bus inspected."

Enhancement 2. In the LRA, the applicant committed to implement the following enhancement to program elements "parameters monitored or inspected," "detection of aging effects," and “acceptance criteria”: “[r]evise appropriate procedures to visually inspect the external surface of MEB external enclosure assemblies for loss of material at least once per every 10 years. The acceptance criterion will be no significant loss of material.”

Enhancement 3. In the LRA, the applicant committed to implement the following enhancement to program element, “detection of aging effects”: “[r]evise appropriate procedures to inspect bolted connections visually at least once every five years or at least once every ten years using thermography.”

During the audit and review, the staff noted that the Metal Enclosed Bus Inspection Program, under “program description,” only discusses visual inspection, but the enhancements to the existing plant program discussed visual inspection as well as thermography. The staff also noted that the site document for the AMP evaluation, Item 3(b), 4(b), and 6(b) discusses visual inspections. However, the existing plant implementing procedures (etc., 480 V metal enclosed buses) discuss micro-ohm checks. The staff requested the applicant to address the inconsistency among site documents and the LRA. The staff also requested the applicant to provide inspection methods as described in GALL Report AMP XI.E4, or provide a basis for not including these methods in the Metal Enclosed Bus Inspection Program (Audit Item 124). In a letter dated March 24, 2008, the applicant stated that as indicated in LRA Section B.1.20, the “Metal Enclosed Bus Inspection Program” is consistent with the inspection methods described in the GALL Report. The program description in LRA Section B.1.20 will be clarified to describe the alternate tests and inspections discussed in the GALL Report, Section XI.E4. Visual inspections will continue to be used for bolted connections as appropriate. The applicant also stated that the site AMP evaluation report will also be clarified as discussed for LRA B.1.20. The program description, and Items 4(b), and 6(b) will be modified to address the inspection methods besides visual that are discussed in the GALL Report AMP XI.E4. Item 3(b) does not require a change, since this item is consistent with the GALL Report. The inspection methods used in the existing site procedure will be reflected in the site AMP evaluation report.

In LRA Amendment 1, dated December 18, 2007, the applicant revised LRA Section B.1.20, “Metal Enclosed Bus Inspection,” Program Description, second paragraph, and the enhancements as follows:

> Program Description
> Inspections of the metal enclosed bus (MEB) include the bus and bus connections, the bus enclosure assemblies, and the bus insulation and insulators. A sample of the accessible bolted connections will be inspected for loose connections. The bus enclosure assemblies will be inspected for loss of material and elastomer degradation. This program will be used instead of the Structures Monitoring Program for external surfaces of the bus enclosure assemblies. The internal portions of the MEB will be inspected for foreign debris, excessive dust buildup, and evidence of moisture intrusion. The bus insulation or insulators are inspected for degradation leading to reduced insulation resistance (IR). The bus insulation will be inspected for signs of embrittlement, cracking, melting, swelling, or discoloration, which may indicate overheating or aging degradation. The internal bus supports or insulators will be inspected for structural integrity and signs of cracks and corrosion. These inspections include visual inspections, as well as quantitative measurements, such as thermography or connection resistance measurements, as required.

Enhancements
Attributes Affected: 3. Parameters Monitored or Inspected; 4. Detection of Aging Effects; 6. Acceptance Criteria
Revise appropriate procedures to visually inspect the external surface of MEB enclosure assemblies for loss of material at least once every 10 years. The first inspection will occur prior to the period of extended operation and the acceptance criterion will be no significant loss of material.

Attributes Affected: 4. Detection of Aging Effects
Revise appropriate procedures to inspect bolted connections at least once every five years if only performed visually or at least once every ten years using quantitative measurements such as thermography or contact resistance measurements. The first inspection will occur prior to the period of extended operation.

The applicant also revised LRA Sections A.2.1.19 and A.3.1.19, Metal Enclosed Bus Inspection Program, second paragraph, as follows:

> Inspections of the metal enclosed bus (MEB) include the bus and bus connections, the bus enclosure assemblies, and the bus insulation and insulators. A sample of the accessible bolted connections will be inspected for loose connections. The bus enclosure assemblies will be inspected for loss of material and elastomer degradation. This program will be used instead of the Structures Monitoring Program for external surfaces of the bus enclosure assemblies. The internal portions of the MEB will be inspected for foreign debris, excessive dust buildup, and evidence of moisture intrusion. The bus insulation or insulators are inspected for degradation leading to reduced insulation resistance (IR). These inspections include visual inspections, as well as quantitative measurements, such as thermography or connection resistance measurements, as required.

In addition, LRA Sections A.2.1.19 and A.3.1.19, Metal Enclosed Bus Inspection Program, third paragraph, second bullet was revised as follows.

> Revise appropriate procedures to inspect bolted connections at least once every five years if only performed visually or at least once every ten years using quantitative measurements such as thermography or contact resistance measurements.

During the license renewal regional inspection, the staff questioned the completeness of acceptance criteria for the internal inspection portion of the program procedures. The applicant agreed to revise the inspection procedures to include more complete acceptance criteria and amended the LRA.

In LRA Amendment 3, dated March 24, 2008, the applicant revised LRA Section A.2.1.19, Metal-Enclosed Bus Inspection Program, third paragraph to add the following enhancement:

> Revise acceptance criteria of appropriate procedures for MEB internal visual inspection inspections to include the absence of indication of dust accumulation on the bus bar, on the insulators, and in the duct, in addition to the absence of

indications of moisture intrusion into the duct.

The applicant also revised LRA Section A.3.1.19, Metal-Enclosed Bus Inspection Program, third paragraph to the following enhancement.

> Revise acceptance criteria of appropriate procedures for MEB internal visual inspection inspections to include the absence of indication of dust accumulation on the bus bar, on the insulators, and in the duct, in addition to the absence of indications of moisture intrusion into the duct.

In addition, the applicant revised LRA Section B.1.20, Metal Enclosed Bus Inspection Program, Enhancements, as follows.

> 6. Acceptance Criteria
>
> Revise the acceptance criteria for MEB internal visual inspections to include the absence of indication of dust accumulation on the bus bar, on the insulators, and in the duct, in addition to the absence of indication of moisture intrusion into the duct.

The staff finds the applicant's response acceptable. With the revisions described above, the applicant's LRA Section B.1.20, FSAR supplements, program basis documents, and plant implementation procedures are consistent with each other. The staff also finds the enhancement acceptable because after enhancements the applicant's MEB program are consistent with the GALL Report XI.E4. The inspection methods as described are consistent with those in the GALL Report AMP XI.E4. The acceptance criteria have been revised to be more complete as agreed to during the regional inspection. The staff verified in letters dated December 18, 2007, and March 24, 2008, that the applicant revised LRA and UFSAR supplement as described above.

Operating Experience. LRA Section B.1.20 states that a comparison of techniques for the cleaning and inspection of metal-enclosed buses at IP2 and IP3 was performed to develop a site-wide program procedure with input from NRC Information Notice 2000-014. The applicant also stated that comparison of program techniques and use of industry findings in the development of site-wide procedures assure continued program effectiveness in managing aging effects for passive components.

The staff noted that the applicant developed a site-wide program based on lessons learned from industry findings and the staff generic communications. The staff finds this information provide evidence to support the conclusion that aging will be managed adequately so that structure and component intended functions will be maintained during the period of extended operation.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.19 and A.3.1.19, the applicant provided the UFSAR supplement for the Metal-Enclosed Bus Inspection Program. The staff reviewed these sections and the amendments as described above, and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by

10 CFR 54.21(d).

As documented in LRA Sections A.2.1.19 and A.3.1.19, the applicant has committed to enhance the program prior to entering the period of extended operation (Commitment 19).

Conclusion. On the basis of its audit and review of the applicant's Metal-Enclosed Bus Inspection Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report, are consistent. In addition, the staff reviewed the exceptions and their justifications and determines that the program is adequate to manage the aging effects for which it is credited. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Oil Analysis Program

Summary of Technical Information in the Application. LRA Section B.1.26 describes the existing Oil Analysis Program as consistent with GALL AMP XI.M39, "Lubricating Oil Analysis," with exception and enhancements.

The Oil Analysis Program maintains oil systems free of contaminants (primarily water and particulates) to preserve an environment that is not conducive to loss of material, cracking, or fouling. Activities include sampling and analysis of lubricating oil in accordance with industry standards such as ISO 4406, ASTM D445, ASTM D4951, and ASTM D96. Water, particle concentration and viscosity acceptance criteria are based on industry standards supplemented by manufacturers' recommendations.

Oil analysis frequencies for IP2 and IP3 equipment are based on Entergy templates with technical basis justifications. These templates are based on EPRI preventive maintenance (PM) bases documents TR-106857 Volumes 1 through 39 and TR-103147. Each template contains sections describing failure location and cause, progression of degradation to failure, fault discovery and intervention, task content and task objective. From information in these sections, frequencies are selected for the components managed by the Oil Analysis Program to mitigate failure. The One-Time Inspection Program includes inspections planned to verify the effectiveness of the Oil Analysis Program.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Oil Analysis Program and basis documents for consistency with GALL AMP XI.M39. Details of the staff's audit of this AMP are documented in the Audit Report. As documented in the report, the staff found that the Oil Analysis Program element "scope of program," is consistent with the respective element in GALL AMP XI.E4. Because this element is consistent with the GALL Report element, the staff finds that it is acceptable.

The staff reviewed the exception and enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited.

In the LRA the applicant states that the Oil Analysis Program includes sampling and analysis of lubricating oil for components within the scope of license renewal and subject to aging management review, that are exposed to lubricating oil, for which pressure boundary integrity or heat transfer is required for the component to perform its intended function. The staff confirmed that the specific components for which the oil analysis program manages aging are identified and the lubricating oil to which these components are exposed is included in the oil analysis program.

In the program basis document, the applicant states that oil systems within the scope of the program are monitored to detect and control abnormal levels of contaminants (primarily water and particulates), thereby preserving an environment that is not conducive to loss of material, cracking, or fouling. In response to staff's inquiries regarding detection of out-of-specification conditions, the applicant stated that the results of lube oil analyses are reviewed by the predictive maintenance group to determine if oil is suitable for continued use until the next scheduled sampling or scheduled oil change. Oil analysis data sheets are provided by an offsite vendor with current and historical analysis results. The data are reviewed to evaluate unusual trends. When degraded conditions are indicated, the predictive maintenance group will take appropriate actions to check the validity of the data and issue a condition report with recommended corrective actions.

The staff confirmed that preventive sampling and analysis activities were included in the implementing procedures.

In Amendment 1 to the LRA, dated December 18, 2007, the applicant revised LRA Sections B.1.26, A.2.1.25 and A.3.1.23 regarding determination of oil sampling frequencies. The applicant stated that oil analysis frequencies for IP2 and IP3 equipment are based on Entergy templates with technical basis justifications. The templates are based on EPRI PM bases documents TR-106857 Volumes 1 through 39 and TR-103147. Each template contains sections describing failure location and cause, progression of degradation to failure, fault discovery and intervention, task content and task objective. From information in these sections, frequencies are selected for the components managed by the Oil Analysis Program to mitigate failure. The staff determined that the sampling frequencies are consistent with current industry standards, and are consistent with the plant technical specifications, where applicable. The sampling frequencies will provide for timely detection of lubricating oil contamination, and will allow corrective actions to be taken, as needed, prior to the loss of intended function. On this basis, the staff finds these sampling frequencies acceptable.

Exception. In the LRA, the applicant took the following exception to the GALL Report program element "parameters monitored or inspected": "NUREG-1801 requires determination of flash point for components that do not have regular oil changes to verify the oil is suitable for continued use. IP does not determine flash point for systems that are not potentially exposed to hydrocarbons. For lubricating oil systems potentially exposed to hydrocarbons, fuel dilution testing is performed in lieu of flash point testing."

The staff noted that the discussion of this exception in LRA Section B.1.26 includes a footnote, which states the following:

> While it is important from an industrial safety perspective to monitor flash point, it has little significance with respect to the effects of aging. Analyses of filter

> residue or particle count, viscosity, total acid/base (neutralization number), water content, fuel dilution, and metals content provide sufficient information to verify the oil is suitable for continued use. IPEC performs a fuel dilution test in lieu of flash point testing on emergency diesel generators and IP3 Appendix R diesel generator lubricating oils. This test accomplishes the same goal as the flash point test but is more prescriptive. The fuel dilution test determines the percent by volume of fuel and water. The analysis can determine the cause of the change in flash point without having to conduct additional tests. Corrective actions, if required, could be implemented on a timelier basis. For oil systems not associated with internal combustion engines, lubricating oil flash point change is unlikely.

The staff noted that the GALL Report AMP XI.M39, states that for components with periodic oil changes in accordance with manufacturer's recommendations, a particle count and check for water are performed to detect evidence of abnormal wear rates, contamination by moisture, or excessive corrosion. Section XI.M39, further states that for components that do not have regular oil changes, viscosity, neutralization number, and flash point are also determined to verify the oil is suitable for continued use.

During an audit, the staff asked the applicant to provide a technical justification for this exception (Audit Item 69). By letter dated March 24, 2008, the applicant referred to the technical basis provided in LRA section B.1.26, exception footnote 1, which states that fuel dilution testing is performed in lieu of flash point testing for lubricating oil systems potentially exposed to hydrocarbons. IP2 and IP3 perform a fuel dilution test in lieu of flash point testing on emergency diesel generators and IP3 Appendix R diesel generator lubricating oils.

The applicant further stated that there are two factors that affect the flash point of the oil: the addition of fuel that would lower the flash point or the addition of water that would raise the flash point. The fuel dilution test determines the percent by volume of fuel and the water content test determines the percent by volume of water. By determining the percent by volume of both fuel and water, the analysis can determine the expected change in flashpoint. While it is important from an industrial safety perspective to monitor flash point, it has little significance with respect to the effects of aging. Analyses of filter residue or particle count, viscosity, total acid/base (neutralization number), water content, fuel dilution, and metals content provide sufficient information to verify the oil is suitable for continued use. For oil systems not associated with internal combustion engines, lubricating oil flash point change is unlikely.

The staff noted that the GALL Report AMP XI.M39 recommends determination of flash point for components that do not have regular oil changes to verify that the oil is suitable for continued use. The applicant performs fuel dilution testing in lieu of flash point determination on lubricating oil systems, such as the emergency diesel generators and the Appendix R diesel, that are potentially exposed to hydrocarbons. The staff reviewed the applicants responses and determined that the performance of fuel dilution testing on lubricating oil systems that are potentially exposed to hydrocarbons will provide for timely detection of lubricating oil degradation or contamination, and will allow corrective actions to be taken, as needed, prior to the loss of intended function. Therefore, the staff concluded that this exception is consistent with the recommendations in the GALL Report and is acceptable.

Enhancement 1. In the LRA, and in Amendment 1 to the LRA, dated December 18, 2007, the applicant committed to implement the following enhancement to program elements "preventive actions," "parameters monitored or inspected," "detection of aging effects," "acceptance criteria," and "corrective actions": "[f]ormalize preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria for all components included in the scope of the program. The program will specify corrective actions in the event acceptance criteria are not met."

The enhancement is necessary to ensure that administrative controls for preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria are in place for all components included in the scope of the oil analysis program.

The staff determined that the applicant's enhancement will add routine preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria for all components included in the scope of the oil analysis program. The screening process is supplemented with detailed analysis in accordance with industry standards such as ISO 4406, ASTM D445, ASTM D4951, and ASTM D96. Water, particle concentration, and viscosity acceptance criteria are based on industry standards supplemented by manufacturers' recommendations. The preliminary oil screening process is, therefore, consistent with the recommendations in the GALL Report. On this basis, the staff finds this enhancement acceptable.

Enhancement 2. In the LRA, the applicant committed to implement the following enhancement to program element "parameters monitored or inspected": "IP2: Revise appropriate procedures to sample and analyze lubricating oil used in the SBO/Appendix R diesel generator consistent with oil analysis for other site diesel generators."

The enhancement is necessary to ensure that administrative controls for sampling and analysis of lubricating oil are in place for all components included in the scope of the oil analysis program. Program activities for sampling and analysis of lubricating oil will be consistent for all diesel generators on the site. The enhancement will ensure that lubricating oil sampling and analysis is included for all components included in the scope of the oil analysis program.

The staff determined that the applicant's enhancement will add routine sampling and analysis of lubricating oil for all diesel generators on the site which is consistent with the recommendations in the GALL Report. On this basis, the staff finds this enhancement acceptable.

Enhancement 3. In the LRA, the applicant committed to implement the following enhancement to program element "parameters monitored or inspected": "[r]evise appropriate procedures to sample and analyze generator seal oil and turbine hydraulic control oil (electrohydraulic fluid)."

The enhancement is necessary to ensure that administrative controls for sampling and analysis of generator seal oil and turbine hydraulic control oil (electrohydraulic fluid). The enhancement will ensure that lubricating oil sampling and analysis is included for all components included in the scope of the oil analysis program.

The staff determined that the applicant's enhancement will add routine sampling and analysis of generator seal oil and turbine hydraulic control oil (electrohydraulic fluid). The enhancement will ensure that lubricating oil is sampled and analyzed for all components on the site within the scope of the oil analysis program which is consistent with the recommendations in the GALL Report. On this basis, the staff finds this enhancement acceptable.

Enhancement 4. In the LRA and in Amendment 1 to the LRA, dated December 18, 2007, the applicant committed to implement the following enhancement to program element "monitoring and trending": "[f]ormalize trending of preliminary oil screening results as well as data provided from independent laboratories."

The enhancement is necessary to ensure that administrative controls for monitoring and trending of preliminary oil screening results and data from independent laboratory analyses are in place for all components included in the scope of the oil analysis program.

The staff determined that the applicant's enhancement will add formalized routine monitoring and screening of preliminary oil screening results and data from independent laboratory analyses for all components included in the scope of the oil analysis program. The screening process is supplemented with detailed analysis in accordance with industry standards such as ISO 4406, ASTM D445, ASTM D4951, and ASTM D96. Water, particle concentration, and viscosity acceptance criteria are based on industry standards supplemented by manufacturers' recommendations. The formalized monitoring and trending of the results of the preliminary oil screening process is, therefore, consistent with the recommendations in the GALL Report. On this basis, the staff finds this enhancement acceptable.

Operating Experience. LRA Section B.1.26 states that analysis of oil samples taken in 1999 through 2006 from the containment spray pump motors showed lube oil in these motors within normal tolerances and satisfactory for continued use. Absence of particulates in a routine sampling program indicates a lack of corrosion, thus proving that the program effectively manages aging effects. Absence of contaminants indicates that the program effectively preserves an environment not conducive to loss of material, cracking, or fouling.

Analysis of an oil sample from a safety injection pump in April 2001 revealed moderate amounts of particulate and contaminates. Analysis of an oil sample from a reactor coolant pump lower bearing in November 2002 indicated a high particulate level. In each case, the lube oil for these pumps was replaced as a priority. Use of warning level indicators to direct corrective actions prior to equipment degradation proves that the program effectively manages aging effects.

Oil analysis results for EDG samples in April and May 2002 indicated increasing metal wear concentrations. IP3 diesel fire pump engine crankcase oil analysis results in June 2003 indicated a trend of elevated metal wear. In each case, the lube oil was replaced and appropriate corrective actions taken. Total acid numbers and viscosity levels from oil samples from service water pump motors in 2006 met warning levels. A 2006 sample of lube oil from a safety injection pump motor also indicated a high total acid number. Because of these data, the motor lube oil was replaced prior to component degradation. Use of warning level indicators to initiate corrective actions prior to equipment degradation assures program effectiveness in managing aging effects.

In June 2006, the applicant compared practices for oil analysis among all Entergy Nuclear Northeast sites and developed an action plan to establish common oil sampling frequencies and analysis techniques based on best practices among the sites. Comparison of program techniques and development of fleet-standard practices assures continued program effectiveness in managing aging effects for passive components.

The staff's review of operating experience documented in the program basis document indicates that this program has been effective in managing aging effects.

The staff confirmed that the “operating experience” program element satisfies the criterion in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.25 and A.3.1.25, the applicant provided the UFSAR supplement for the Oil Analysis Program.

In Amendment 1 to the LRA, Attachment 1, Audit Item 166, dated 18 December 2007, the applicant revised the first paragraph of Section A.2.1.25 and the first paragraph of Section A.3.1.25 as follows:

> The Oil Analysis Program is an existing program that maintains oil systems free of contaminants (primarily water and particulates) thereby preserving an environment that is not conducive to loss of material, cracking, or fouling. Activities include sampling and analysis of lubricating oil in accordance with industry standards such as ISO 4406, ASTM D445, ASTM D4951 and ASTM D96. Water, particle concentration and viscosity acceptance criteria are based on industry standards supplemented by manufacturer's recommendations.

In Amendment 1 to the LRA, dated December 18, 2007, the applicant revised the second paragraph of Sections A.2.1.25 and A.3.1.25 as follows:

> Oil analysis frequencies for IP2 and IP3 equipment are based on Entergy templates with technical basis justifications. Procedure EN-DC-335, "PM Bases Template", is based on EPRI PM bases documents TR-106857 volumes 1 thru 39 and TR-103147. Each template contains sections describing failure location and cause, progression of degradation to failure, fault discovery and intervention, task content and task objective. From information in these sections, frequencies are selected for the components managed by the Oil Analysis Program to mitigate failure.

In Amendment 1 to the LRA, dated December 18, 2007, the applicant revised the fourth paragraph of Section A.2.1.25 as follows:

> The Oil Analysis Program will be enhanced to include the following.
>
> - Revise appropriate procedures to sample and analyze lubricating oil used in the SBO/Appendix R diesel generator consistent with oil analysis for other site diesel generators.
>
> - Revise appropriate procedures to sample and analyze generator seal oil and turbine hydraulic control oil (electrohydraulic fluid).
>
> - Formalize preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria for all components included in the scope of the program. The program will specify corrective actions in the event acceptance criteria are not met.
>
> - Formalize trending of preliminary oil screening results as well as data provided from independent laboratories.

In Amendment 1 to the LRA, dated December 18, 2007, the applicant revised the fourth paragraph of Section A.3.1.25 as follows:

> The Oil Analysis Program will be enhanced to include the following.
>
> - Revise appropriate procedures to sample and analyze generator seal oil and turbine hydraulic control oil (electrohydraulic fluid).
>
> - Formalize preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria for all components included in the scope of the program. The program will specify corrective actions in the event acceptance criteria are not met.
>
> - Formalize trending of preliminary oil screening results as well as data provided from independent laboratories.

The staff reviewed these sections and determines that the information in the UFSAR supplement, as amended, is an adequate summary description of the program, as required by 10 CFR 54.21(d).

As documented in LRA Sections A.2.1.25 and A.3.1.25, the applicant has committed to enhance the program prior to entering the period of extended operation (Commitment 18).

Conclusion. On the basis of its audit and review of the applicant's Oil Analysis Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report, are consistent. In addition, the staff reviewed the exception and its technical justification and determines that the program is adequate to manage the aging effects for which it is credited. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Reactor Vessel Surveillance Program

Summary of Technical Information in the Application. LRA Section B.1.32 describes the existing Reactor Vessel Surveillance Program as consistent with GALL AMP XI.M31, "Reactor Vessel Surveillance," with enhancement.

The Reactor Vessel Surveillance Program manages reduction in fracture toughness of reactor vessel beltline materials to maintain the pressure boundary function of the reactor pressure vessel through the period of extended operation. The program, based on ASTM E-185, "Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels," as required by 10 CFR Part 50, Appendix H, evaluates radiation damage shown by pre- and post-irradiation testing of Charpy V-notch and tensile specimens. The rate at which these specimens accumulate radiation damage will be higher than that of the vessel because the specimens are closer to the core than the vessel itself.

Under the Reactor Vessel Integrity Program, reports submitted as required by 10 CFR Part 50, Appendix H include a capsule withdrawal schedule, a summary report of capsule withdrawal and test results, and, if needed, a technical specification change for pressure-temperature limit curves. The program, which meets ASTM E-185 recommendations and complies with 10 CFR Part 50, Appendix H, evaluates radiation damage shown by pre- and post-irradiation testing of Charpy V-notch and tensile specimens from the most limiting plate in the core region of the reactor vessel (RV).

Staff Evaluation. During its review, the staff confirmed the applicant's claim of consistency with the GALL Report. The staff reviewed the enhancements to determine whether the AMP, with the enhancements, remained adequate to manage the aging effects for which it is credited.

The Reactor Vessel Surveillance Program is identified as consistent with the program described in GALL Report, Section XI.M31, "Reactor Vessel Surveillance," with enhancements. The enhancements are: (1) to withdraw and test a standby capsule to cover the peak reactor vessel fluence that is expected through the end of the period of extended operation; and (2) to revise procedures to require that tested and untested specimens from all capsules pulled from the reactor vessel be maintained in storage.

The staff reviewed the enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited.

Enhancement. In the LRA, the applicant committed to implement the following enhancement:

> The specimen capsule withdrawal schedules will be revised to draw and test a standby capsule to cover the peak reactor vessel fluence expected through the end of the period of extended operation.
>
> Appropriate procedures will be revised to require that tested and untested specimens from all capsules pulled from the reactor vessel are maintained in storage.

In Commitment 22, the applicant stated that it will revise the specimen capsule withdrawal schedules for IP2 and IP3 to withdraw and test a standby capsule to cover the peak RV neutron fluence expected through the end of the period of extended operation.

The withdrawal schedules will be submitted as required by 10 CFR Part 50, Appendix H, Section III.B.3.

In response to the staff's RAI B.1.1.32-1, the applicant provided the lead factors for each standby capsule, the materials available to be tested in each capsule, and the date for capsule withdrawal to ensure that the neutron fluence of the surveillance capsule will be equal or greater than the peak RV neutron fluence through the end of the period of extended operation. The response by the applicant is contained in their letter dated November 28, 2007.

Indian Point Nuclear Generating Unit No. 2 has three remaining capsules with lead factors of 1.2. The capsules contain surveillance test specimens from plates B2002-1, B2002-2 and B2002-3 and correlation monitor material. The lead factor is the ratio of the neutron fluence of the capsule to the neutron fluence of the reactor vessel. Therefore, the IP2 capsules will receive 20 percent more neutron fluence than the IP2 RV.

To ensure that the neutron fluence of the surveillance capsule will be equal to or greater than the peak RV neutron fluence through the end of the period of extended operation, at least one capsule will remain in the RV until approximately 40 effective full power years (EFPY). This burnup should be attained approximately 8 years prior to the end of the period of extended operation or around 2025.

Indian Point Nuclear Generating Unit No. 3 has three remaining capsules with lead factors of 1.52. Capsules W and U have surveillance test specimens from plates B2803-3 and B2802-1 and weld metal. Capsule V has surveillance test specimens from plate B2803-3 material, weld metal, ASTM reference material and weld heat affected zone material. Since the lead factor is 1.52, the IP3 capsules will receive 52 percent more neutron fluence than the IP3 RV.

To ensure that the neutron fluence of the surveillance capsule will be equal to or greater than the peak RV neutron fluence through the end of the period of extended operation, a capsule must remain in the RV until approximately 32 EFPY. This burnup should be attained approximately 16 years prior to the end of the period of extended operation or around 2019.

The staff finds that the testing of the surveillance capsules in accordance with the proposed schedule provides reasonable assurance that the neutron-induced embrittlement in low alloy steel RV base metals and their associated welds will be adequately monitored during the extended period of operation. Additionally, the staff finds that the applicant's Reactor Vessel Surveillance Program complies with the requirements of the 10 CFR Part 50, Appendix H.

Operating Experience. LRA Section B.1.32 states that an updated RV surveillance capsule withdrawal schedule for IP2 was submitted to the staff in November 2004. Information from the surveillance program throughout the IP2 operating history was included in this request to change the previous schedule. The staff determined that the new withdrawal schedule met the 1982 Edition of ASTM E-185 criteria and complied with 10 CFR Part 50, Appendix H. Review of the surveillance requirements against industry standards, confirmed through staff oversight, assures continued program effectiveness in managing reduction in fracture toughness for RV beltline materials.

A summary of IP3 surveillance capsule exposure was prepared in a November 2003 neutron fluence evaluation for the unit's power uprate. This evaluation will be used to project the neutron exposure of the reactor vessel for future operating periods at the uprated power level. The surveillance capsule lead factors in this calculation will be the basis for development of future capsule withdrawal schedules. Review of the surveillance program due to changes from the power uprate assures continued program effectiveness in managing reduction in fracture toughness for reactor vessel beltline materials.

The staff confirmed that the "operating experience" program element satisfies the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.31 and A.3.1.31, the applicant provided the UFSAR supplement for the Reactor Vessel Surveillance Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

As documented in LRA Sections A.2.1.31 and A.3.1.31, the applicant has committed to enhance the program prior to entering the period of extended operation (Commitment 22).

Conclusion. On the basis of its review of the applicant's Reactor Vessel Surveillance Program, the staff determined that those program elements, for which the applicant claimed consistency with the GALL Report, are consistent. Also, the staff reviewed the enhancement and confirmed that its implementation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Steam Generator Integrity Program

Summary of Technical Information in the Application. LRA Section B.1.35 describes the existing Steam Generator Integrity Program as consistent with GALL AMP XI.M19, "Steam Generator Tube Integrity," with enhancement.

In the industry, steam generator (SG) tubes have experienced degradation from corrosion phenomena (e.g., PWSCC, outside diameter SCC, intergranular attack, pitting, and wastage) with other mechanically-induced phenomena (e.g., denting, wear, impingement damage, and fatigue). NDE techniques detect defective tubes that must be removed from service or repaired in accordance with plant technical specifications. The Steam Generator Integrity Program monitors and maintains secondary side component integrity. The program defines inspection and maintenance schedules, scope of work, and methods. The Steam Generator Integrity Program is consistent with NEI 97-06, "Steam Generator Program Guidelines."

Staff Evaluation. During its review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff reviewed the program elements of the Steam Generator Integrity Program to verify consistency with GALL AMP XI.M19. Based on the staff's review, the staff determined that Steam Generator Integrity elements "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria," are consistent with the corresponding elements in GALL AMP XI.M19. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited.

Enhancement. In the LRA, the applicant committed to implement the following enhancement program element "monitoring and trending": "[r]evise appropriate procedures to require that the results of the condition monitoring assessment are compared to the operational assessment performed for the prior operating cycle with differences evaluated."

The applicant has committed to enhancing the program by requiring that the results of the condition monitoring assessment be compared to the operational assessment performed for the prior cycle with the differences evaluated. The operational assessment is performed at the completion of an inspection to demonstrate that SG tube integrity will be maintained during the up-coming operating cycle. It predicts what tube degradation will occur during operation, until the next planned inspection, and evaluates SG tube structural integrity and leakage integrity for that predicted level of degradation. The condition monitoring assessment is performed with as-found tube degradation data on a defect-specific basis, to demonstrate compliance with integrity criteria by the comparing the NDE measurements with calculated burst and leakage integrity limits. Calculated integrity limits, including consideration for appropriate uncertainties, burst and leak analytical correlations, material properties, NDE technique, and analyst uncertainties are provided in the degradation assessment report.

The staff agrees that this comparison and evaluation is an important attribute of an acceptable Steam Generator Integrity Program that should be performed and will result, long term, in a more robust program. The enhancement will be consistent with the guidance in NEI 97-06, “Steam Generator Program Guidelines,” which endorses the EPRI “Steam Generator Integrity Assessment Guideline,” (EPRI TR 107621). The EPRI guidelines state that condition monitoring results are to be evaluated with respect to the previous operational assessment and if the operational assessment did not bound the condition monitoring, then an analysis, in accordance with the plant corrective action program, shall be performed. Since these guidelines are consistent with the GALL Report, the staff finds that this enhancement is acceptable.

In RAI 3.1.2.2.14-1, dated December 7, 2007, the staff requested that the applicant provide additional details on the SG secondary side inspections performed on the feedwater inlet rings for each unit, to monitor for wear and loss of material due to flow accelerated corrosion.

In its response, by letter dated January 4, 2008, the applicant provided the following information. The IP2 SGs were replaced in 2000. The feedwater rings in the replacement SGs are not scheduled to be inspected until 2010. This planned inspection will be for two of the four SGs. The acceptance criteria for the inspection are the absence of any unusual conditions. Any conditions that do not meet this criterion will require further evaluation. This inspection frequency and criteria are acceptable based on the relatively short operating time of the new SGs and that the Steam Generator Integrity Program is implemented in accordance with NEI 97-06, “Steam Generator Program Guidelines,” which includes inspections to assure secondary side component integrity.

The IP3 SGs were replaced in 1989. Since that time there have been 5 different inspections of all or some of the feedwater rings: in 1992 all 4 SGs were inspected, in 1997 SG 34, in 1999 SG 33, in 2001 SG 32, and in 2007 SGs 31 & 32. The scope of the inspections performed in 1997 through 2007 consisted of a visual exam of the outer diameter of the ring and a fiberscope inspection of the inner diameter of 5 selected J-nozzles (out of 36 total) and the feedwater ring tee. The next feedwater ring inspection for IP3 is planned for 2 SGs in 2013. No anomalies were noted in the prior inspections other than the appearance of minor washed out areas on the exterior of the feedwater ring beneath the outlets of the J-nozzles. The feedwater entering the steam generators exits the J-nozzles welded to the feedwater ring such that the discharge is directed downward towards the exterior of the feedwater ring. The feedwater ring is a carbon steel pipe that has a thin oxide film on the exterior surface. The flow from the J-nozzles prevents this oxide buildup giving the appearance of washed out areas where this feedwater impact occurs. Visual inspections of these washed out areas did not identify any loss of material on the feedwater ring.

Based on the applicant's response to the RAI describing the secondary side inspections performed to detect feedwater ring degradation, the staff finds the applicant's response to the RAI 3.1.2.2.14-1 acceptable. The staff's concern in RAI 3.1.2.2.14-1 is resolved.

Operating Experience. LRA Section B.1.35 states that IP2 SGs replaced in December 2000 began operating at uprated power levels in November 2004. IP3 SGs replaced in 1989 began operating at uprated power levels in April 2005.

A March 2003 IP3 SG degradation assessment per NEI 97-06 Revision 1 and the EPRI PWR Steam Generator Examination Guidelines Revision 5 (EPRI TR-107569) summarized the inspection results of IP3 replacement SGs since their installation in refueling outage 3R7 (1989), compared them to industry operating experience, and described a refueling outage 3R12 (2003) inspection plan based on this input. Use of plant-specific and industry operating experience and industry guidance in the development of an inspection plan assures program effectiveness in managing aging effects for passive components.

All indications from inspections of the IP3 SGs in March 2003 (refueling outage 3R12) were below calculated integrity limits in the pre-outage degradation assessment. During these refueling outage inspections, the staff evaluated the SG integrity assessment program and compared it to the staff-accepted guidance of EPRI "PWR Steam Generator Examination Guidelines," Revision 5 (EPRI TR-107569). To evaluate implementation of the SG assessment program, the staff witnessed SG tube testing and secondary side inspection processes and made no significant findings. Confirmation of program compliance with established standards and regulations assures effective program management of passive component aging.

The applicant revised the IP2 program procedure in June 2005 to incorporate the results of the September 2004 INPO Steam Generator Review Visit and the IP3 program procedure in July 2005 to incorporate the latest EPRI guidelines. Review of existing practices by industry groups, implementation of process improvements, and incorporation of industry guidelines assure continued program effectiveness in managing aging effects for passive components.

An INPO-assisted self-assessment of the IP2 and IP3 SG programs in September 2004 generated actions that led to program improvement in several key areas. Detection of program weaknesses and subsequent corrective actions assure continued program effectiveness in managing loss of component material.

An IP2 SG degradation assessment in April 2006 per NEI 97-06 Revision 1 and the EPRI TR-107569 summarized the inspection results of IP2 replacement SGs since their installation in December 2000, compared the results to industry operating experience, and listed a refueling outage 2R17 (2006) inspection plan based on this input. Use of plant-specific operating experience, industry operating experience, and industry guidance in the development of an inspection plan assures continued program effectiveness in managing aging effects for passive components.

All indications from inspections of the IP2 SGs in April 2006 were below calculated integrity limits in the pre-outage degradations assessment.

In April 2006, the regional inspection staff reviewed portions of the SG management plan, degradation assessment, and the final operational assessment to evaluate the SG inspection and management program. The staff reviewed plant-specific SG information, tube inspection criteria, integrity assessments, degradation modes, and tube plugging criteria. Entergy conducted eddy current testing of tubes in all SGs to detect and quantify tube degradation mechanisms and to confirm tube integrity following the completion of two fuel cycles of operation. The staff observed a sample of tubes from each generator to verify Entergy's examination of the entire length and made no significant findings. Confirmation of program compliance with established standards and regulations assures effective program management of passive component aging. The staff evaluated the SG tube inspection report for the inspections performed during 2006, 2R17 refueling outage and concluded the applicant provided the information required by the technical specifications and that the applicant's inspection program appears to be consistent with the objective of detecting potential tube degradation and with industry operating experience at similarly designed units.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.34 and A.3.1.34, the applicant provided the UFSAR supplement for the Steam Generator Integrity Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

As documented in LRA Sections A.2.1.34 and A.3.1.34, the applicant has committed to enhance the program prior to entering the period of extended operation (Commitment 24).

Conclusion. On the basis of its review of the applicant's Steam Generator 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 cited enhancement and confirmed that its implementation prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Structures Monitoring Program

Summary of Technical Information in the Application. LRA Section B.1.36 describes the existing Structures Monitoring Program as consistent with GALL AMP XI.S6, "Structures Monitoring Program," with enhancements.

The applicant states that Structures Monitoring Program inspections are in accordance with 10 CFR 50.65 (Maintenance Rule) as addressed in Regulatory Guide 1.160 and NUMARC 93-01. Periodic inspections monitor the condition of structures and structural components for loss of intended function. As protective coatings are not relied upon to manage the effects of aging for structures in the Structures Monitoring Program, the program does not address protective coating monitoring and maintenance.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Structures Monitoring Program to verify consistency with GALL AMP XI.S6. Details of the staff's audit of this AMP are documented in the Audit Report. As documented in the report, the staff found that the Structures Monitoring Program elements "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria," are consistent with the corresponding elements in GALL AMP XI.S6. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited.

Enhancement 1. In the LRA, the applicant committed to implement the following enhancement to program element of "scope of program":

> Appropriate procedures will be revised to explicitly specify that the following structures are included in the program.
>
> - Appendix R emergency diesel generator foundation (IP3)
> - Appendix R emergency diesel generator fuel oil tank vault (IP3)
> - Appendix R emergency diesel generator switchgear and enclosure (IP3)
> - city water storage tank foundation
> - condensate storage tanks foundation (IP3)
> - containment access facility and annex (IP3)
> - discharge canal (IP2/3)
> - emergency lighting poles and foundations (IP2/3)
> - fire pumphouse (IP2)
> - fire protection pumphouse (IP3)
> - fire water storage tank foundation (IP2/3)
> - gas turbine 1 fuel storage tank foundation
> - maintenance and outage building–elevated passageway (IP2)
> - new station security building (IP2)
> - nuclear service building (IP1)
> - primary water storage tank foundation (IP3)
> - refueling water storage tank foundation (IP3)
> - security access and office building (IP3)
> - service water pipe chase (IP2/3)
> - service water valve pit (IP3)
> - superheater stack
> - transformer/switchyard support structures (IP2)
> - waste holdup tank pit (IP2/3)

From the applicant's description, the staff could not identify the complete scope of the program. Very significant enhancements to the "scope of program" are identified, but there is no description of the scope of the existing program, and there is no explanation why such major enhancements to the program scope are needed for license renewal. While most of the added structures serve a license renewal intended function for 10 CFR 54.4(a)(3), about half of these structures also serve license renewal intended functions for 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(2). In accordance with RG 1.160 and NUMARC 93-01 these structures would be expected to be included in the current existing program.

In an audit question, the staff asked Entergy to (1) describe the structures and structural components inspected as part of the existing structures monitoring program; and (2) explain why 11 structures listed in the “scope of program” enhancement have intended functions for 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(2) (Audit Item 85).

By letter dated December 18, 2007, the applicant responded to the audit item. In its response to (1), Entergy provided a list of the structures and structural components which are inspected as part of the existing Structures Monitoring Program. The staff reviewed this list and confirmed that it matched the list of existing structures presented in the program basis documents (PBDs).

In its response to (2), for each of the structures listed in the enhancement to the “scope of program” that have intended functions for 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(2), Entergy described its function and its specific intended function for license renewal. The staff reviewed this information and finds the response acceptable.

<u>*Enhancement 2*</u>*.* In the LRA, the applicant committed to implement the following enhancement to program element “scope of program”:

> Appropriate procedures will be revised to clarify that in addition to structural steel and concrete, the following commodities are inspected for each structure as part of the Structures Monitoring Program:
>
> - cable trays and supports
> - concrete portion of reactor vessel supports
> - conduits and supports
> - cranes, rails, and girders
> - equipment pads and foundations
> - fire proofing (pyrocrete)
> - HVAC duct supports
> - jib cranes
> - manholes and duct banks
> - manways, hatches, and hatch covers
> - monorails
> - new fuel storage racks
> - sumps, sump screens, strainers and flow barriers

The staff notes that the specific commodities listed would be expected to be included in the current existing program if they are safety-related or important to safety. In an audit question, the staff asked Entergy to (1) describe the structural commodities inspected as part of the existing structures monitoring program; and (2) explain why the 13 commodities are identified as an enhancement to the “scope of program” (Audit Item 86).

By letter dated December 18, 2007, the applicant responded to the audit item. In its response to (1), Entergy explained that the structural commodities inspected as part of the existing program include structural steel beams, columns, and end connections; support steel (e.g., instrument racks, base plates); and concrete surfaces. Individual inspection checklists are provided in the program procedures for each commodity.

In its response to (2), Entergy explained that these 13 commodities are routinely inspected under the existing Structures Monitoring Program (AMP B.1.36); however, they are not explicitly identified in the program procedures. Therefore, this enhancement will be implemented to ensure that these commodities are explicitly identified in the program.

The staff concurs that all of the commodities identified in the enhancement need to be explicitly included in the Structures Monitoring Program (SMP). Anchorages (base plates, grout, and steel anchors) and connections (welds or bolts) to building steel, associated with all applicable supports should also be clearly identified. During follow-up audit discussions with Entergy, Entergy proposed to add the phrase "(including their anchorages)" to confirm that the support anchorages are included in the Structures Monitoring Program. The staff accepted Entergy's proposal. This additional enhancement to the "scope of program" element has been added to Commitment 25, in Revision 1 of the List of Regulatory Commitments, submitted by Entergy on December 18, 2007.

The staff also reviewed the LRA Structures AMR Tables 3.5.2-1 through -4 and noted that several structural components, which credit AMP B.1.36 for aging management, are not specifically identified in the existing program scope or in the enhancement. In an audit question, the staff requested Entergy to confirm that all component type/aging effect combinations that credit the Structures Monitoring Program for aging management in Tables 3.5.2-1 through 3.5.2-4 are included in the scope of the Structures Monitoring Program, and are inspected for the designated aging effect (Audit Item 244). In its response, dated December 18, 2007, Entergy stated that all component type/aging effect combinations that credit the Structures Monitoring Program for aging management in Tables 3.5.2-1 through 3.5.2-4 are inspected for designated aging effects; however, some structural components are not specifically identified in the scope of the Structures Monitoring Program. The staff finds this acceptable, because this AMP is applicable to aging management of the vast majority of structures and structural components in the plants.

<u>Enhancement 3</u>. In the LRA, the applicant committed to implement the following enhancement to program elements of "scope of program," and "detection of aging effects":

> Guidance will be added to the Structures Monitoring Program to inspect inaccessible concrete areas that are exposed by excavation for any reason. IPEC will also inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring.

The staff finds this enhancement acceptable, because it provides additional appropriate guidance for inspection.

<u>Enhancement 4</u>. In the LRA, the applicant committed to implement the following enhancement to program element "detection of aging effects": "[r]evise applicable structures monitoring procedures for inspection of elastomers (seals, gaskets, seismic joint filler, and roof elastomers) to identify cracking and change in material properties and for inspection of aluminum vents and louvers to identify loss of material."

The staff finds this enhancement acceptable, because it provides additional guidance for inspection.

Enhancement 5. In the LRA, the applicant committed to implement the following enhancement to program element "detection of aging effects":

> Guidance to perform an engineering evaluation of groundwater samples to assess aggressiveness of groundwater to concrete on a periodic basis (at least once every five years) will be added to the Structures Monitoring Program. IPEC will obtain samples from a well that is representative of the ground water surrounding below-grade site structures. Samples will be monitored for sulfates, pH and chlorides.

The staff notes that Entergy's above enhancements to the Structures Monitoring Program are necessary for license renewal.

In an audit question, the staff requested Entergy to (Audit Item 87):

(a) describe past and present groundwater monitoring activities at the Indian Point site, including the sulfates, pH and chlorides readings obtained; and the location(s) where test samples were/are taken relative to the safety-related and important-to-safety embedded concrete foundations; and

(b) Explain the technical basis for concluding that testing a single well every five (5) years is sufficient to ensure that safety-related and important-to-safety embedded concrete foundations are not exposed to aggressive groundwater.

By letter dated December 18, 2007, the applicant responded to the audit item. In response to (a), Entergy stated:

> There is a sufficient number of analytical results to ensure that the ground water is being properly monitored. Large numbers of groundwater wells located adjacent to the structures have been sampled and were analyzed for sulfate and chloride at a contract laboratory, with pH having been determined at the time of sample collection. The data indicates that the ground water is non-aggressive (pH >5.5, Chloride <500 ppm and Sulfate <1500 ppm). Several samples taken along the facility waterfront and adjacent to the discharge canal were noted to have higher than normal levels of chloride. Given the location of samples, these higher than normal levels are believed to be due to the salinity of the brackish Hudson River water at the Indian Point location of the river. In all cases pH results are >5.5 and sulfate concentration < 1500 mg/L. Ground water samples will continue to be obtained on a quarterly basis for one calendar year in order to fully characterize these parameters (Chloride, Sulfate, and pH) for the groundwater at IPEC to account for any seasonal variation. The selected sample locations will provide representative samples of the ground water in the vicinity of the structures. A review of the several hundred ground water pH values collected in late 2005 to present reveal that the ground water had a pH of >5.5 in all cases except four. In those four cases, pH was found to be <5.5 standard unit (SU). All four of these low pH samples were obtained from the same sample point on the same day. To date all subsequent samples taken from this sample point were found to have a pH >5.5 SU.

In response to (b), Entergy stated: that at least five (5) wells will be tested. A sample frequency of five years in a limited number of wells (at least five wells) adjacent to safety structures and those falling under 10 CFR 54.4 (a)(1) and 10 CFR 54.4 (a)(2) would be sufficient to confirm the non-aggressive nature of the ground water. The large sample population for the initial characterization, the diverse locations from which the samples were obtained and the seasonality of sample collections contribute to Entergy's confidence in the understanding of the nature of the ground water. Additionally, Entergy stated it would not normally expect to see the ground water conditions change unless an extraordinary event occurred, such as major withdrawals (such as significant pumping out the ground water) or injections of water on the site or in the vicinity of the site.

The staff finds Entergy's responses to be acceptable, on the basis that (1) extensive sampling has been recently conducted, without evidence of an aggressive below-grade environment; and (2) Entergy has committed to increase the sample size from one well to at least five wells in the vicinity of in-scope buried concrete structural elements. This new commitment was added to Commitment 25, in Revision 1 of the List of Regulatory Commitments, submitted by Entergy on December 18, 2007.

In LRA Appendix B, Table B-2, the applicant stated that GALL AMP XI.S7 is not credited for aging management of water control structures. Instead, the Structures Monitoring Program manages the effects of aging on the water control structures at IP. GALL AMP XI.S7 offers this option, provided all the attributes of GALL AMP XI.S7 are incorporated in the applicant's Structures Monitoring Program.

In an audit question, the staff requested Entergy to (1) identify the specific water control structures that have an intended function for license renewal, and are included in the scope of AMP B.1.36; (2) describe the attributes of AMP B.1.36 that pertain to aging management of water control structures; and (3) explain how these attributes of AMP B.1.36 encompass the attributes of GALL AMP XI.S7, without exception (Audit Item 88).

By letter dated December 18, 2007, the applicant responded to the audit item. In its response to (1), Entergy indicated that the water control structures that have an intended function for license renewal and are included (or will be included) in the scope of the AMP B.1.36 are the intake structure (including intake structure enclosure) and the discharge canal. Since the discharge canal is not specifically stated in the structures monitoring procedures, Entergy indicated that an enhancement for AMP B.1.36 will be to explicitly specify the discharge canal.

The staff concludes that the Structures Monitoring Program B.1.36 can be used to manage aging of the IP water-control structures, in lieu of GALL AMP XI.S7 (RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants).

In its response to (2), Entergy described the attributes of AMP B.1.36 that pertain to aging management of water-control structures. More detailed information was provided in Entergy's response to part (3) of the audit question.

In it response to (3), Entergy provided a description of how the ten attributes of AMP B.1.36 encompass the attributes of GALL AMP XI.S7. Compared to the five year intervals recommended for inspection in GALL AMP XI.S7, Entergy indicated the Structures Monitoring Program (AMP B.1.36) similarly uses intervals of five years for accessible areas and opportunistic inspections for buried components. The staff did not find this consistent with GALL

AMP XI.S7 for submerged structures. During follow-up audit discussions with Entergy, Entergy proposed to revise LRA Commitment 25, to add the following: "Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspection of normally submerged concrete portions of the intake structures at lease once every 5 years, or earlier if determined to be necessary." The staff accepted Entergy's proposal, on the basis that it is consistent with GALL AMP XI.S7. This enhancement was added to Commitment 25, in Revision 1 of the List of Regulatory Commitments, submitted by Entergy on December 18, 2007.

Based on the staff's review of the LRA, the basis documents, Entergy's responses to the audit items discussed above, and Entergy's additions to Commitment 25, submitted on December 18, 2007, the staff concludes that the "scope of program," "parameters monitored or inspected," and the "detection of aging effects" program elements are consistent with the GALL Report. Also, consistent with the GALL report, the preventive actions program element is not applicable.

Operating Experience. LRA Section B.1.36 states that inspections of structural steel, concrete exposed to fluid, and structural elastomers from 2001 through 2005 revealed signs of degradation: cracks, gaps, and corrosion (rust). Monitoring of concrete structures and components from 2001 through 2006 identified only minor cracks that did not affect the structural integrity of the components. Monitoring of structural steel members revealed only minor corrosion. The applicant states that inspection intervals, adjusted as necessary, ensure that future inspections detect degradation prior to loss of intended function. The applicant also states that detection of degradation and corrective action prior to loss of intended function assure program effectiveness in managing aging effects for structural components.

The staff reviewed the discussion of operating experience for the existing plant-specific Structures Monitoring Program. In addition, the staff reviewed a number of condition Reports (CRs) that briefly describe occurrences of structural degradation at IP2 and IP3. Based on review of the CR summaries, the staff identified a number of apparently significant conditions of aging degradation of structures that are not identified in the LRA, the basis documents for the Structures AMPs, or the Structures AERM.

In a series of audit questions related to plant-specific operating experience for structures, the staff asked Entergy to provide additional information for the following types of degraded conditions:

Water Control Structures Degradation (Audit Item 358)
IP2 Reactor Cavity Leakage (Audit Item 359)
IP2 Spent Fuel Pool Crack/Leak Paths (Audit Item 360)
IP2 Containment Dome Concrete Spalling (Audit Item 361)

The staff referenced specific CRs that described each type of degradation, and asked Entergy to discuss:

(a) history of the degradation
(b) evaluation of the extent of degradation
(c) operability assessments performed
(d) corrective actions taken (describe in detail)
(e) the current status of the degraded condition
(f) corrective actions planned prior to the LR period

(g) special or augmented aging management requirements during the period of extended operation
(h) license renewal commitments

By letter dated, March 24, 2008, the applicant provided responses to the above questions. The staff evaluated Entergy's response for IP2 Containment Dome Concrete Spalling (Audit Item 361) in its assessment of Entergy's Containment ISI Program, LRA AMP B.1.8. See Section 3.0.3.3.2 of this SER.

Water Control Structures Degradation (Audit Item 358)

In its response for Water Control Structures Degradation, dated March 24, 2008, Entergy described the noted degraded conditions in greater detail, summarized corrective actions taken, and identified the current status of the degradation. For degraded areas that have not been repaired, Entergy will continue to monitor the degradation under the Structures Monitoring Program during the extended period of operation. However, Entergy initially made no commitment for augmented inspection during the extended period of operation for the degraded areas that have not been repaired. The staff informed Entergy that its responses to Items (g) and (h) needed additional clarification and also requested Entergy to provide the technical basis as to why augmented inspection during the extended period of operation is not necessary for the degraded areas.

The applicant provided its supplemental response in a letter dated August 14, 2008. In its response, the applicant stated that evaluations conducted under its corrective action program indicated the degraded conditions did not compromise intended functions at this time. The applicant committed to perform more frequent inspection of these locations (every three years instead of five years) under its Structures Monitoring AMP (Commitment 25).

The applicant has committed to more frequent inspection of the degraded water control structures, which is consistent with the GALL Report recommendation. The GALL Report references RG 1.160 for Maintenance Rule monitoring of structures. RG 1.160 recommends more frequent monitoring for areas of known degradation. The staff concludes that a 3 year monitoring frequency is sufficient to identify further degradation before there is loss of intended function. Therefore, the staff finds the applicant's response and supplemental clarification for Audit Question 358 to be acceptable.

IP2 Reactor Cavity Leakage (Audit Item 359)

In its response dated March 24, 2008, for IP2 Reactor Cavity Leakage, Entergy described the degraded conditions in greater detail, summarized corrective actions taken, and identified the current status of the degradation. The reactor cavity at IP2 has a history of leakage at the upper elevations of the stainless steel cavity liner when flooded during refueling outages. There is a relatively free flow of water behind the liner, down to the 46-foot elevation inside containment. Attempts have been made over the last several outages to mitigate this condition, with limited success. An action plan is being developed for a permanent fix to this issue. Two technologies are being investigated for the permanent solution.

For the extended period of operation, Entergy will rely on the Structures Monitoring Program for aging management of the reactor cavity concrete and containment internal structures. For aging management of the cavity steel liner, Entergy will rely on the Water Chemistry Control – Primary and Secondary Program. However, Entergy made no commitment for augmented inspection during the extended period of operation. The staff informed Entergy that its responses to Items (g) and (h) needed additional clarification. In a follow-up discussion relating to Audit Question 359, the staff expressed its concern with regard to the potential for degradation of the underlying concrete and reinforcement due to the leakage of borated water through the cavity liner and potential impact of the leakage on other adjacent structures. The staff requested Entergy to provide the technical basis as to why augmented inspection during the extended period of operation is not necessary, if the recurring leak condition is not permanently fixed.

The applicant provided its supplemental response in a letter dated August 14, 2008. In its response, the applicant stated that the leakage is entirely contained within and is collected in the lower elevation of the containment building. The cavity water leakage is easily replaced from the refueling water storage tank. The collected leakage is pumped to the radioactive liquid waste processing system and the leakage does not affect structures other than the refueling cavity. The applicant stated that the leakage does not pose a threat to the structural integrity of the refueling cavity reinforced concrete walls, which are 4 feet thick, and cited several documented tests that concluded borated water does not significantly degrade concrete properties. In addition, a core sample was removed from the IP2 refueling cavity wall in 1993. Examination showed that the depth of penetration of borated water was ½ inch into the concrete at that time. The applicant stated that substantial design margins are available in the concrete and reinforcement. The applicant emphasized that the flooded condition, and therefore the leakage exists for about 2 weeks out of a refueling cycle of about 1.5 years. A number of attempts have been made to rectify this condition, but to date have not been completely successful. The applicant indicated that it will continue to work toward a permanent fix, but will prioritize this effort based on its safety significance and availability of site resources. The applicant has committed to perform a one-time inspection and evaluation of a sample of potentially affected refueling cavity concrete, including embedded reinforcing steel, prior to the period of extended operation, in order to provide additional assurance that the concrete walls have not degraded (Commitment 36).

As noted at the beginning of this program section, the applicant claims that it is consistent with the GALL Report AMP XI.S6 with enhancements. The GALL Report AMP recommends that for each structure/aging effect combination, the specific parameters monitored or inspected should be selected to ensure that aging degradation leading to loss of intended functions will be detected and the extent of degradation can be determined. For the program element “detection of aging effects,” the AMP recommends that for each structure/aging effect combination, the inspection methods, inspection schedule, and inspector qualifications should be selected to ensure that aging degradation will be detected and quantified before there is loss of intended functions. The staff notes that the applicant plans to enhance the “detection of aging effects” element of its Structures Monitoring Program to inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring. However, the leakage is occurring in inaccessible areas, and a similar environment may not exist for accessible areas of concrete.

The staff concluded that Entergy’s commitment to perform a one-time inspection and evaluation of a sample of potentially affected refueling cavity concrete, including embedded reinforcing steel, prior to the period of extended operation, is appropriate in order to assess the current state of the concrete and rebar. However, because the applicant does not plan to perform periodic inspections of the refueling cavity and affected area, the staff determined that for this structure/environment/aging effect combination, the applicant is not consistent with the GALL Report AMP. Additionally, the applicant’s program did not address concrete exposed to borated water.

In a telephone call with Entergy on August 27, 2008 (Audit Item 359), the applicant described its plan for permanent remediation of the IP2 refueling cavity leakage problem. By letter dated November 6, 2008, the applicant submitted a supplemental response to Audit Question 359, describing its plan for implementing a permanent fix over the next three (3) scheduled IP2 refueling outages (2010, 2012, 2014).. At the time of issuance of the SER with Open Items, the staff was in the process of reviewing the applicant’s response. Therefore, this issue was identified as Open Item 3.0.3.2.15-1.

Entergy’s proposed plan to mitigate the refueling cavity leak includes:

- 2008 / 2009 - Research available technologies to repair leaks in the refueling cavity.
- Spring 2010 refueling outage - Repair area of north wall weld seams in the vicinity of the Ceramoloy patch and south wall along area of disbonded Ceramoloy patch.
- Spring 2012 refueling outage - Repair east wall where large Ceramoloy patch has disbonded and area around access ladder on northwest corner.
- Spring 2014 refueling outage - Repair areas of lower cavity where Ceramoloy patches have disbonded, and miscellaneous areas observed as suspect from past inspections.
- During each of the preceding outages, areas not permanently repaired will be temporarily repaired by the application of Instacote. Beginning in the refueling outage in Spring 2016, no Instacote will be applied, to allow Entergy to determine if repairs have successfully stopped the leakage. If not, additional areas will be repaired in subsequent outages until the leakage is corrected.

The staff reviewed the applicant's response dated November 6, 2008, and noted that the applicant did not make a license renewal commitment to permanently remediate the refueling cavity leakage. Therefore, the staff determined that the applicant should define an appropriate aging management program to be implemented if the remediation plan is not completely successful in stopping the leakage.

In an effort to resolve this open item, the staff issued follow-up RAI 1: Open Item 3.0.3.2.15-1 (Audit Question 359), dated April 3, 2009, in which the staff requested the following information:

> (a) . . . provide additional information on the leakage path from the refueling cavity to the collection point lower in containment, as well as the leak flow-rate. In this regard, describe the leakage path and chemical composition of the leaking fluid, provide historical flow-rate values, and confirm whether or not any leakage enters the reactor cavity inside the primary shield wall. Provide the technical basis as to how the leakage path was determined, with a focus on water entering the reactor cavity. Provide a sketch of containment and the refueling cavity which highlights the leakage path.

(b) . . . In absence of a formal commitment to remedy the source of leakage, the applicant's aging management program (AMP) should include a method to monitor for a degrading condition in the refueling cavity, and other structures and components that would be affected by the leakage, during the period of extended operation, or the applicant should explain how the structures monitoring program will adequately manage potential aging of this region during the period of extended operation.

In letter dated May 1, 2009, Entergy responded to follow-up RAI 1: Open Item 3.0.3.2.15-1 (Audit Question 359), stating as follows:

(a) During the first refueling outage in 1976, leakage from the refueling cavity was observed coming from the reactor cavity. The original designed temporary seal between the reactor vessel flange and the reactor cavity was not leak tight. The leakage collected in the reactor cavity pit sump and was pumped out. A plant modification was initiated to use a new design seal, which resolved the problem. Leakage also occurred in the reactor vessel inlet and outlet blow out plugs and instrumentation wireways. Leakage through these paths has been minimized by improving sealing methods. The leakages from the above sources were not from behind the reactor cavity liner and through concrete construction joints.

In 1993, it was determined that leakage from the refueling cavity was coming through the liner plates. This event initiated detailed investigations and corrective actions to stop the leakage. Unfortunately, the sealing methods have not fully resolved the leakage. The suspect leakage path was determined by visual observation during and after filling the refueling cavity with water. Leakage is observed as the cavity is filled for refueling operations. Leakage starts as the cavity level reaches the 80 ft. elevation which is approximately 50% cavity level. Leakage was observed initially from three significant areas associated with refueling cavity construction. [Applicant referenced Figure 1, included with the response.] Leakage from the refueling cavity collects in a drainage trench on the 46 ft elevation of containment inside the crane wall from where it flows to the containment sump.

A small portion of the leakage from the refueling cavity enters the reactor cavity flowing down the interior primary shield walls to a sump located in the reactor cavity from where it is pumped to the containment sump. Leakage inside the reactor cavity has been primarily attributed to non-liner leakage associated with reactor cavity seal and nozzle inspection box cover isolation issues.

The leaking fluid from the refueling cavity is mixed reactor coolant and refueling water storage tank water with total estimated flow rates on the order of 3 to 7 gpm. No samples of the fluid flowing from the leaking areas have been analyzed for chemical composition. There has been no degradation of containment structural surfaces from this wetting as observed in the Structures Monitoring Program. [Applicant referenced

Figures 1 through 4, included with the response, for sketches of the containment area and the refueling cavity which show the locations of the observed leakage.]

(b) As previously described in IPEC Letter NL-08-127 dated August 14, 2008, Audit Question 359, the refueling cavity is a robust structure, with thick walls and low stress levels when compared to the total structural capacity. Exposure to borated water has not resulted in identified degradation or reduction of structural integrity. Industry and IPEC operating experience for the past years has shown that concrete is not significantly affected by exposure to borated water. The refueling cavity is wet during the limited duration (approximately 14 days) when it is filled and is dry during the subsequent period (approximately 24 months) of normal power operations. Moisture remaining following draining of the cavity would be dried up by the ambient temperatures resulting from reactor operation, thus long-term exposure to borated water that could cause significant degradation of the concrete and embedded reinforcement is not expected.

The method to monitor for a degrading condition in the refueling cavity is routine visual inspection of accessible concrete surfaces under the Structures Monitoring Program accompanied by an inspection of concrete that has been exposed to the intermittent borated water leakage for an extended period. The inspection is required by the formal commitment to do core bore samples in the upcoming outage in 2010 for concrete that has been exposed to the leaking borated water on an intermittent basis for much of the life of the plant. If leakage occurs during the upcoming outage, IPEC will obtain a sample of leaking water at an exit point below the cavity and evaluate it for fluid composition.

The results of the sample analysis will be evaluated to establish whether additional aging management activity is necessary during the period of extended operation. Additionally core bore samples will be taken, if leakage is not stopped prior to the end of the first ten years of the period of extended operation (Reference Commitment #36). Other structures and components that could be affected by the leakage that are not addressed under the Structures Monitoring Program would be evaluated under the Boric Acid Corrosion Program. As previously committed to in IPEC Letter NL-08-127, dated August 14, 2008, inspections and activities related to the identification of leakage in the refueling cavity and its impact on the surrounding concrete will provide reasonable assurance that the associated structures will remain capable of fulfilling their license renewal intended functions. The established site operating experience review program ensures that any subsequent new industry or IPEC operating-experience will be incorporated to ensure adequate management of potential aging effects of this region during the period of extended operation.

The staff reviewed the applicant's May 1, 2009 response and concluded that additional clarifications were needed before the staff could make a determination whether the applicant's revised commitments are sufficient to ensure there will be no loss of intended function during the 20 year extended period of operation.

In an effort to resolve this issue, the staff issued follow-up RAI 2: Open Item 3.0.3.2.15-1, dated May 20, 2009, which requested the following:

(a) In part (a) of the applicant's response, Figures 1 through 4 do not clearly identify the flow path from the refueling cavity liner to the A, B, and C water exit locations. . . . In an elevation view (similar to Figure 2), cut through each of the exit locations A, B, and C, showing the horizontal and vertical dimension between the entry point through the liner and the exit location. To the extent possible, describe the possible circumferential traverse of the leakage, from the entry point through the liner to the exit location.

(b) The staff requests the applicant to provide the following additional information/clarification regarding the revised license renewal commitments in part (b) of the applicant's response:

(1) The current remediation plan has targeted the 2014 outage for completion. Please identify actions that will be taken if the remediation plan is unsuccessful.

(2) Identify the specific location and number of the concrete core samples (e.g., the three water exit locations) that will be removed and tested (i) during the upcoming 2010 refueling outage, and (ii) at 10 years into the extended period of operation (if a permanent solution for the leakage has not been achieved, in accordance with Entergy's current remediation plan). Define the tests that will be performed, and the objective of each test.

(3) Please advise if the revised commitments in the applicant's May 1, 2009 response include chemical analysis of the leaking water (i) during the upcoming 2010 refueling outage, and (ii) at 10 years into the extended period of operation. Please identify the analyses that will be performed, and the objective of each analysis.

In its response, dated June 12, 2009, Entergy responded to follow-up RAI 2: Open Item 3.0.3.2.15-1 as follows:

a. Based on leakage investigations, the reactor refueling cavity begins to leak when the water in the cavity reaches an approximate elevation between 80'- 85'. As can be seen on the attached elevation views of the cavity (Entergy provided Figures 1 thru 4 in its response), horizontal weld seams exist between these elevations, but the exact liner leakage points are unknown. We can, however, make the following observations regarding the relationship between the leakage areas in the concrete structure denoted as points A, B and C, and conditions of the cavity liner:

1. Above point A, defects in the CeramAlloy patch along a horizontal weld seam located on the south wall at an elevation between 80'– 85' has been observed. The CeramAlloy patch material that covers several weld seams was a previous attempt to mitigate the cavity leakage. This is a potential cavity liner leak point for the observed leakage on the concrete structure at point A.

2. Above the exit point denoted as B, defects in a CeramAlloy patch along a horizontal weld seam located at an elevation between 80'– 85' on the south wall has been observed. This patch area is an extension from the area discussed in Item 1 above. In addition, the upper internals stand support base is attached to the cavity floor above the vicinity of the observed leakage in the concrete structure at point B. Both these areas in the cavity liner are potential leak point sources for the observed leakage at point B.

3. Above the observed leakage area in the concrete structure denoted as point C, defects in both the CeramAlloy patches along weld seams and potential defects in the weld seams themselves at the north cavity wall have been observed. These defects are located approximately 10-15' above the cavity floor and are potential leak points for the leakage observed at point C.

b. The following provides Entergy's response to part (b) of the staff's request.

1. Should the remediation plan for the cavity liner targeted for completion during the 2014 outage be unsuccessful, Entergy will perform additional monitoring to assess the condition of potentially affected structures. To assure continued structural integrity of the reactor refueling cavity reinforced concrete walls, Entergy will perform further core sampling and inspect reinforcing steel at suspect locations as described in Item 3.

2. (i) During the upcoming 2010 outage, a total of 3 core bore samples will be taken from the reinforced concrete walls that form the outer shell of the reactor refueling cavity steel liner. The locations of these core bores will be chosen based on the following:

    - Locations in the vicinity of observed liner/liner patch degradation in relative proximity to the observed leak points A, B and C on the concrete structure.

    - Accessibility of suspect areas based on the principle of As Low As Reasonably Achievable (ALARA) and physical interferences.

    The core samples will be tested and chemically analyzed to determine the effect, if any, past leakage has had on the concrete properties. The objectives of the physical and chemical tests of the concrete core samples are as follows:

- Determine the compressive strength of concrete.
- Determine boron and chloride concentration in concrete.
- Determine pH of concrete.

In addition, a petrographic examination will be performed on the core samples to evaluate the cementitious matrix, and, to the extent possible, determine the durability of the concrete.

In addition, reinforcing steel in the core sample areas will be exposed and inspected. Visual inspections of the reinforcing steel will be performed to determine the extent of material loss, if any, from the steel as a result of the borated water leakage.

(ii) If a solution to the leakage has not been achieved, Entergy will perform core samples and reinforcing steel inspections prior to 10 years into the period of extended operation. Locations of the core samples will be chosen based on the extent and location of the leakage remaining following previous repair efforts. Core samples will be tested and chemically analyzed as discussed under part 2 above. Visual inspections of the reinforcing steel will be performed to determine the extent of material loss, if any, from the steel as a result of the borated water leakage.

3. (i and ii) Revised Commitment 36 includes chemical analysis of water leakage from the refueling cavity. During the upcoming 2010 outage, Entergy will collect water samples from the cavity leak and perform chemical analysis. If the leakage has not been stopped, Entergy will collect additional water samples of the leak during the same outage as the core samples are taken, no later than 10 years into the period of extended operation. The water that is collected will be analyzed for the following:

   - Boron concentration
   - pH
   - Iron
   - Calcium

   Results of the analysis will be evaluated to assess the aggressiveness of the leaking fluid to reinforced concrete structures.

The staff reviewed the applicant's responses to the staff's RAIs and clarification concerning the IP2 refueling cavity leakage (Audit Item 359) provided in letters dated March 24, 2008, August 27, 2008, November 6, 2008, May 1, 2009, May 20, 2009, and June 12, 2009. The staff noted the following:

- The borated water leakage during the reactor refueling operations has not adversely affected the structural integrity of the refueling cavity concrete structure. The leakage occurs for a short duration (approximately 14 days) during refueling outages (normally every 24 months). Visual examination of the leakage areas has not identified any degradation of concrete. In addition, previous studies and testing by the nuclear industry and the applicant have not identified any degradation of the concrete or reinforcement when exposed to low concentrations of borated water.

- The applicant has committed to take three core bore samples of the concrete, at the observed leakage locations, during the upcoming 2010 outage. The samples will determine the compressive strength and the pH value of concrete, as well as the boron and chloride concentration in the concrete. This information will be used to determine the effect of borated water on the concrete. Petrographic examination of the core samples will also help identify the effect of borated water on the durability of the IP2 refueling cavity area concrete prior to the period of extended operation.

- Visual examination of reinforcement exposed during core boring of concrete during the 2010 outage will identify any material loss due to corrosion resulting from interaction with borated water.

- The applicant has committed to analyze the water leaking from the refueling cavity for boron concentration, pH, iron, and calcium during the 2010 outage. This analysis will provide additional information on the effect of the leakage on the reinforced concrete structures.

- The applicant's goal is to permanently remediate the refueling cavity leakage by the end of the 2014 refueling outage. Since the leakage is the source of possible degradation, eliminating the leakage will also eliminate the possible degradation mechanism. However, if the remediation is unsuccessful, the applicant has committed to re-inspect the concrete, rebar, and leaking water prior to the tenth year of extended operation. The staff finds the timing of this inspection acceptable based on site-specific operating experience. IP2 has experienced refueling cavity leakage since 1993, which means the concrete has been exposed to the leakage during refueling outages for at least 16 years with no visible signs of degradation. If the 2010 inspections also show no degradation after 16 plus years of intermittent leakage, there is reasonable assurance that a follow-up inspection within 10 years will detect any future degradation prior to a loss of intended function of the refueling cavity structures.

Based on the inspections conducted to date and the actions the applicant is planning to take prior to and during the period of extended operation, the staff finds that the aging effects on the IP2 refueling cavity concrete will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3). Therefore, Open Item 3.0.3.2.15-1 is closed.

IP2 Spent Fuel Pool Crack/Leak Paths (Audit Item 360)

In its response for IP2 spent fuel pool (SFP) crack/leak paths, Entergy described the noted degraded conditions in greater detail, summarized corrective actions taken, and identified the current status of the degradation. The leakage was first discovered during excavation for the IP2 Fuel Storage Building in 2005. Entergy believes the conditions leading to leakage have been corrected.

For the extended period of operation, Entergy will rely on the Structures Monitoring Program for aging management of the spent fuel pool concrete, and rely on the Water Chemistry Control – Primary and Secondary Program and monitoring of the pool level per technical specifications for aging management of the spent fuel pool stainless steel liner. However, Entergy made no commitment for augmented inspection during the extended period of operation. The staff informed Entergy that its responses to Items (g) and (h) needed additional clarification. Due to the lack of a leak-chase channel system at IP2 to monitor, detect and quantify potential leakage through the SFP liner, the staff is concerned that there has been insufficient time following the corrective actions to be certain that the leakage problems have been permanently corrected. In a follow-up discussion with regard to Audit Question 360, the staff requested Entergy to provide the technical basis as to why augmented inspection during the extended period of operation is not necessary.

The applicant provided its detailed response in a letter dated August 14, 2008. In its response, the applicant stated that all known sources of leakage from the IP2 spent fuel pool have been eliminated based on the inspections and repairs already implemented. The licensee stated that it completed, in 2007, a one-time inspection of the accessible 40 percent of the SFP liner above the fuel racks and 100 percent of the SFP transfer canal liner using general visual, robotic cameras and vacuum box testing techniques. To provide additional indication of potential spent fuel pool leakage, the applicant has committed to test the groundwater outside the IP2 spent fuel pool for the presence of tritium from samples taken from adjacent monitoring wells, every 3 months. The presence of tritium in the groundwater could be indicative of a continuing leak from the spent fuel pool (Commitment 25). The applicant has also revised the LRA description of its Structures Monitoring AMP to include this special testing as an enhancement.

Although Entergy has taken corrective action and has committed to quarterly monitoring for tritium in the groundwater, the staff was concerned that hidden degradation of concrete and rebar may have resulted from prior leakage, and may be continuing if there is still an active leakage mechanism. In a telephone call with Entergy on September 3, 2008, the staff requested the applicant to submit additional relevant information on the condition of concrete and rebar in areas where leakage was detected, and the existing design margins in these areas.

By letter dated November 6, 2008, the applicant submitted a supplemental response to Audit Item 360, which provided a detailed description of (1) the design margins for the spent fuel pool concrete walls; and (2) the results of prior concrete core sample testing and rebar corrosion testing. At the time of issuance of the SER with Open Items, the staff was in the process of reviewing the applicant’s response. Therefore, this issue was identified as Open Item 3.0.3.2.15-2. The applicant’s letter of November 6, 2008, provided the following information:

> IPEC analyzed the capability of the east spent fuel pool pit wall and the south spent fuel pool pit wall to resist the design basis loads considering potential concrete and reinforcement steel degradation due to observed leakage of fluids through these walls. Finite Element models for both the east and south walls were developed to determine the actual forces in the walls due to loading resulting from the design basis earthquake, hydrostatic forces and dead weight. Due to the symmetry of the spent fuel pit structure, results from the evaluation of these two walls are applicable to the remaining north and west walls. The following summarizes the results and conclusions from these two analyses.

East Wall Evaluation

The capacity of the east wall was evaluated in response to possible degradation due to an observed leak in 1992. It was determined that work in the spent fuel pool in 1990 initiated the leak by inadvertently creating a small hole in the stainless steel liner. This condition was repaired in 1992. A total of 20 core bores were taken from 5 locations on the east wall in the vicinity of the observed leakage to determine the condition of the concrete following exposure to borated water leakage. At each of the 5 locations, 4 individual cores 4" in diameter and 15" in length were taken, resulting in a total depth of penetration into the wall of 60". In addition, several windows in the outer surface of the wall were created to allow inspection of the outer layer of reinforcing steel. Of the 20 cores taken, all but one had compressive strengths that exceeded the design strength of 3000 psi. This one core outlier had a measured compressive strength of 2400 psi.

The lower value was attributed to its close proximity to a known concrete sub-surface delamination in the wall and was not considered to be representative of the general condition of the wall. Analysis of the concrete matrix showed that the borated water had little or no effect on the concrete itself. Little or no corrosion was observed in the rebar except at a location in the wall where spalling had occurred exposing rebar to the elements. Analysis of the rust particles showed high chloride content and low boron concentration indicating that rainwater was the primary cause of the observed corrosion. To determine the available margin in the east wall, moments were calculated using a finite element plate model. The results of the analysis showed the east wall was capable of resisting the applicable forces without any reinforcing steel and would incur little or no cracking as a result of the design loading. Conservatively assuming that the concrete would crack and the bending moments would be carried by the reinforcing steel, the following minimum margins exist with respect to the ultimate moment capacity of the wall. In other words, the load bearing capability of the wall is at least 31% greater than the required load bearing capability.

Northeast Corner 1/ 4to 1/2 wall depth: 31%
Mid Span 1/ 4to 1/2 wall depth: 43%

South Wall Evaluation

An evaluation determined the margins in the south wall due to possible rebar degradation as a result of observed fluid emanating from a crack discovered in the west corner during excavation for the dry cask storage project. The reinforcing steel in the area of the observed leak was exposed for inspection. The condition of the reinforcing steel was good with little or no corrosion. To determine the actual forces in the south wall due to the design basis loads, a finite element model of the wall was developed. Based on the resulting moments from the analysis, the margins in the south wall with respect to the ultimate moment capacity of the concrete section are as noted below:

Section with Horizontal Steel at Wall Center: 45%
Section with Horizontal Steel at Crack Location: 51%
Section with Vertical Steel at Crack Location: 57%

Section with Vertical Steel at Base: 25%

The available margins in the east and south walls of the spent fuel pool pit with respect to the as-designed condition range from a low of 25% at the base of the wall for the vertical steel to a high of 57% for the vertical steel at the crack location in the west corner of the wall. The margins for the horizontal rebar at wall mid span range from 43%-45% and up to 51% in the vicinity of the observed crack.

The staff reviewed the applicant's November 6, 2008 response, and determined that additional clarifications were necessary before it could conclude that the applicant's proposed aging management program for the extended period of operation is sufficient.

In an effort to resolve this open item, the staff issued follow-up RAI 2: Open Item 3.0.3.2.15-2 (Audit Question 360), dated April 3, 2009, which requested the following:

(a) In Commitment 25, the applicant commits to sample for tritium in groundwater wells in close proximity to the IP2 spent fuel pool at least every three months to assess for potential indications of spent fuel pool leakage. This commitment does not describe what actions will be taken if leakage continues. If sampling indicates continued leakage, the applicant's AMP should include a method to determine if a degraded condition exists during the period of extended operation, or the applicant should explain how the Structures Monitoring Program will adequately manage potential aging of the inaccessible concrete of the IP2 spent fuel pool due to borated water leakage during the period of extended operation.

(b) The second paragraph on page 2 of Attachment 1 of the clarification letter dated November 6, 2008, states in part: "[l]ittle or no corrosion was observed in the rebar except at a location in the wall where spalling had occurred exposing rebar to the elements. Analysis of the rust particles showed high chloride content and low boron concentration indicating that rainwater was the primary cause of the observed corrosion." The staff requests the applicant to identify any Unit 2 and Unit 3 operating experience related to rebar corrosion, in light of the chloride content in rainwater, and identify the likely source for the high chloride content in the rainwater. Additionally, the applicant is requested to explain whether and how the AMP is adequate to address this environment and the related potential aging effects to ensure there is no loss of intended function during the period of extended operation.

By letter dated May 1, 2009, Entergy provided the following response to follow-up RAI 2: Open Item 3.0.3.2.15-2 (Audit Question 360):

(a) As indicated in Entergy letter NL-08-127, dated August 14, 2008, Audit Question 360, degradation has not been attributed to the effects of aging, but to poor construction and workmanship practices during initial construction activities. Consequently, future degraded conditions are not expected.

The method to determine if a degraded condition exists during the period of extended operation is continued monitoring for leakage by monitoring SFP level and monitoring ground water in the vicinity of the pool exterior walls for indications of pool leakage. The absence of leakage will indicate no degraded condition exists. Leakage, if any, indicates potential degradation. If leakage is found, it will be evaluated under the corrective action program (i.e., Element 7 of the SMP). If sampling indicates that ground water contains constituents indicating pool leakage then evaluation is required under the corrective action program to assess the potential for degradation and determine appropriate corrective actions. An example of the aggressive corrective actions expected in response to identified leakage is found in the condition report described in response to Audit Question 360, Entergy Letter NL-08-127, dated August 14, 2008. Corrective actions for that condition included inspections of all accessible surfaces of the SFP liner, installation of monitoring wells in the vicinity, performance of UT examinations, bore samples, rebar inspections and inspections using remote camera technology.

As stated in the Statement of Consideration (SOC) for the license renewal rule, 'Given the Commission's ongoing obligation to oversee the safety and security of operating reactors, issues that are relevant to current plant operation will be addressed by the existing regulatory process within the present license term rather than deferred until the time of license renewal.' Since the issue of SFP leakage is currently being addressed by the existing licensing and regulatory process that process provides reasonable assurance that appropriate corrective actions will be taken during the current license term. Those actions will continue as appropriate through the period of extended operation.

(b) The original 1993 consultant analysis associated with the degraded concrete area speculated that the likely source for the high chloride content was condensation of chloride laden air (chlorides from the brackish Hudson River water) on the outer surface of the pool wall. It has since been concluded that the chloride source was likely associated with the use of rock salt or storage of chemicals or materials in the area.

Studies of the chloride content in rain water and ground water do not support the levels that were found in 1993. Studies typically show the national average of chlorides in rain water to be a maximum of 1.0 to 1.5 parts per million (PPM) with values inland approaching 0.2 PPM. The National Atmospheric Deposition Program (NAPD), Hudson Valley location West Point station, located upriver from the plant, chloride data from 1983 to 2007 shows values from 0.18 to 0.66 PPM. This is significantly lower than the values initially reported and does not support the supposition that chlorides originated from rainwater. No IP operating experience has linked high chlorides in rainwater to corrosion of embedded rebar. The pool wall was repaired eliminating the spent fuel pool rebar exposure to rainwater.

> The aging management programs for concrete exposed to the elements, the Structures Monitoring Program and the Containment ISI Program, are adequate to address this environment and the related potential aging effects to ensure there is no loss of intended function during the period of extended operation. Visual inspections performed under these programs have confirmed no loss of intended function due to aging effects. These programs will continue to monitor potential future degradation of the concrete cover that could result in exposure of the underlying rebar to the outdoor environment.
>
> Minor degradation that has been observed during these inspections has shown little change between inspections confirming the adequacy of the inspection frequency of the Structures Monitoring and Containment ISI Programs. If rebar degradation is identified during future inspections (e.g., observation of concrete staining during visual inspection), the condition will be evaluated in accordance with the program requirements to ensure necessary corrective actions are taken to prevent loss- of intended function.

The staff reviewed the applicant's response dated May 1, 2009 and the applicant's previous responses concerning spent fuel pool leakage. The staff noted the following:

- A leak in the East wall of the spent pool liner was originally observed and repaired in 1992. This leak was traced to work performed in the spent fuel pool during 1990. The applicant took 20 core bore samples of the concrete from the affected wall and tested them. In addition, the condition of the reinforcement in the core bored areas was visually examined. Detailed structural analysis of the spent fuel pool structure was performed that concluded that the condition of the spent fuel pool walls was adequate to resist the postulated design loads.

- Spent fuel pool leakage was again observed in 2005. The applicant performed extensive testing of the spent pool liner using visual, robotic camera, and vacuum box testing techniques in 2007 and eliminated all known sources of spent fuel pool leakage.

- Currently there is no evidence of continued leakage from the IP2 spent fuel pool.

- The applicant has committed to sample for tritium in the groundwater wells in close proximity to the IP2 spent fuel pool every three months (Commitment 25). Tritium in the groundwater would indicate leakage from the spent fuel pool, which may lead to degradation. Any identified leakage will be reviewed and the corrective action program will be used to determine the appropriate actions.

Based on inspections conducted under the applicant's Structures Monitoring Program, and the applicant's additional commitment to monitor the groundwater samples from monitoring wells adjacent to the spent fuel pool, there is reasonable assurance that any degradation of the IP2 spent fuel pool would be identified, and evaluated within the corrective action program prior to loss of intended function. Therefore, the staff concludes that the effects of aging will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3). On this basis, Open Item 3.0.3.2.15-2 is closed.

UFSAR Supplement. In LRA Sections A.2.1.35 and A.3.1.35, the applicant provided the UFSAR supplement for the Structures Monitoring Program. By letter dated March 24, 2008, the applicant revised LRA Sections A.2.1.35 and A.3.1.35 and Commitment 25 to: (1) include inspection of anchorages of certain commodities; (2) inspect inaccessible concrete areas that are exposed by excavation for any reason, and inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant degradation is occurring; (3) perform inspections of elastomers to identify cracking and change in material properties, and inspections of aluminum vents and louvers to identify loss of material; (4) obtain samples from at least five monitoring wells that are representative of the ground water surrounding below-grade site structures and perform an engineering evaluation of the results; (5) inspect normally submerged concrete portions of the intake structures at least once every 5 years, and inspect the baffling/grating partition and support platform of the IP3 intake structure at least once every 5 years; and (6) inspect the degraded areas of the water control structure once per 3 years rather than the normal frequency of once per 5 years during the period of extended operation. By letter dated June 12, 2009, the applicant revised Commitment 36, which complements the Structures Monitoring Program, as discussed above. The staff reviewed these sections, as revised, and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

As documented in LRA Sections A.2.1.35 and A.3.1.35, the applicant has committed to enhance the program prior to entering the period of extended operation (Commitment 25).

Conclusion. On the basis of its audit and review of the applicant's Structures Monitoring Program, and review of the applicant's responses to the staff's RAIs, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report, are consistent therewith. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.16 Water Chemistry Control - Closed Cooling Water Program

Summary of Technical Information in the Application. LRA Section B.1.40 describes the existing Water Chemistry Control - Closed Cooling Water Program as consistent with GALL AMP XI.M21, "Closed-Cycle Cooling Water System," with exceptions and enhancements.

The Water Chemistry Control - Closed Cooling Water Program includes preventive measures that manage loss of material, cracking, or fouling for components in closed cooling water systems: CCW, instrument air closed cooling, EDG cooling, SBO/Appendix R diesel generator cooling (IP2), Appendix R diesel generator cooling (IP3), security generator cooling, conventional closed cooling (IP2 only), and turbine hall closed cooling (IP3 only). These chemistry activities monitor and control closed cooling water chemistry using IP procedures and processes based on EPRI guidelines for closed cooling water issued as EPRI TR-1007820, "Closed Cycle Cooling Water Chemistry," Revision 1, dated April 2004, superseding EPRI TR-107396, "Closed Cycle Cooling Water Chemistry Guideline," Revision 0, issued November

1997, and a reference in the GALL Report. A description of differences between Revision 0 and Revision 1 follows.

The purpose of Revision 0 was to assist plants in developing water treatment strategies to protect carbon-steel and copper-containing systems from corrosion. This revision provides not precise, but broad direction for plants to develop closed cooling water chemistry control programs by utilizing the report to tailor specific station programs. Revision 0 does not provide tables for “control parameters” and “diagnostic parameters” with respective sampling frequency and expected values. However, it shows parameters that should be monitored as “control parameters” or “diagnostic parameters.” In general, Revision 0 allows plants a great deal of flexibility in developing their closed cooling water chemistry programs.

Revision 1 is significantly more directive and incorporates action levels with established thresholds for specific actions required. This revision specifically establishes recommended monitoring frequencies and clearly specifies expected parameter values. Revision 0 treats total organic carbon, dissolved oxygen, total alkalinity, calcium/magnesium, and refrigerants as diagnostic but these are not described in Revision 1 which considers none of these parameters (or monitoring of them) as having any effect on the long-term condition of closed cycle cooling water systems.

Both EPRI closed cycle cooling water guidelines distinguish clearly between “control parameters” and “diagnostic parameters.” Adherence to control parameters is expected whereas diagnostic parameters are suggested but can be plant-specific. Deviations from EPRI recommended diagnostic parameters are not exceptions to the GALL Report.

Future revisions of the EPRI closed cycle cooling water guidelines will be adopted as required commensurate with industry standards. The One-Time Inspection Program for Water Chemistry utilizes inspections or NDEs of representative samples to verify whether the Water Chemistry Control - Closed Cooling Water Program has been effective in managing aging effects.

Staff Evaluation. During its audit and review, the staff confirmed the applicant’s claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Water Chemistry Control - Closed Cooling Water Program to verify consistency with GALL AMP XI.M21. Details of the staff’s audit of this AMP are documented in the Audit Report. As documented in the report, the staff found that the Water Chemistry Control - Closed Cooling Water Program element “scope of program” is consistent with the corresponding element in GALL AMP XI.M21. Because this element is consistent with the GALL Report element, the staff finds that it is acceptable.

The staff reviewed the exceptions and enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited.

Exception 1. In the LRA, the applicant took the following exception to the GALL Report program element “parameters monitored or inspected”: “NUREG-1801 states the program monitors the effects of corrosion and SCC by testing and inspection in accordance with guidance in EPRI TR-107396. The IPEC Water Chemistry Control - Closed Cooling Water Program does not perform performance and functional testing.”

The staff noted that the discussion of this exception in Section B.1.40 of the LRA includes a footnote, which states the following:

While NUREG-1801, Section XI.M21, Closed Cycle Cooling Water System endorses EPRI report TR-107396 for performance and functional testing guidance, EPRI report TR-107396 does not recommend that equipment performance and functional testing be part of a water chemistry control program. This is appropriate since monitoring pump performance parameters is of little value in managing effects of aging on long-lived, passive CCW system components. Rather, EPRI report TR-107396 states in Section 5.7 (Section 8.4 in EPRI report 1007820) that performance monitoring is typically part of an engineering program, which would not be part of water chemistry. In most cases, functional and performance testing verifies that component active functions can be accomplished and as such would be included as part of maintenance rule (10 CFR 50.65) programs. Passive intended functions of pumps, heat exchangers and other components will be adequately managed by the Water Chemistry Control – Closed Cooling Water Program and One-time Inspection Program through monitoring and control of water chemistry parameters and verification of the absence of aging effects.

Exception 2. In the LRA, the applicant took the following exception to the GALL Report program element "detection of aging effects": "NUREG-1801 recommends the use of performance and functional testing to ensure acceptable function of the CCCW systems. The IPEC Water Chemistry Control - Closed Cooling Water Program does not perform performance and functional testing."

The staff noted that the discussion of this exception in Section B.1.40 of the LRA includes a footnote, which states the following:

While NUREG-1801, Section XI.M21, Closed Cycle Cooling Water System endorses EPRI report TR-107396 for performance and functional testing guidance, EPRI report TR-107396 does not recommend that equipment performance and functional testing be part of a water chemistry control program. This is appropriate since monitoring pump performance parameters is of little value in managing effects of aging on long-lived, passive CCW system components. Rather, EPRI report TR-107396 states in Section 5.7 (Section 8.4 in EPRI report 1007820) that performance monitoring is typically part of an engineering program, which would not be part of water chemistry. In most cases, functional and performance testing verifies that component active functions can be accomplished and as such would be included as part of maintenance rule (10 CFR 50.65) programs. Passive intended functions of pumps, heat exchangers and other components will be adequately managed by the Water Chemistry Control – Closed Cooling Water Program and One-time Inspection Program through monitoring and control of water chemistry parameters and verification of the absence of aging effects.

Exception 3. In the LRA, and in Amendment 1 to the LRA, Attachment 1, Audit Item 95, dated December 18, 2007, the applicant took the following exception to the GALL Report program element "monitoring and trending": "NUREG-1801 recommends internal visual inspections and performance and functional tests periodically to demonstrate system operability. The IPEC Water Chemistry Control - Closed Cooling Water Program does not perform component performance and functional testing."

The staff noted that the discussion of this exception in Section B.1.40 of the LRA includes a footnote, which states the following:

> While NUREG-1801, Section XI.M21, Closed Cycle Cooling Water System endorses EPRI report TR-107396 for performance and functional testing guidance, EPRI report TR-107396 does not recommend that equipment performance and functional testing be part of a water chemistry control program. This is appropriate since monitoring pump performance parameters is of little value in managing effects of aging on long-lived, passive CCW system components. Rather, EPRI report TR-107396 states in Section 5.7 (Section 8.4 in EPRI report 1007820) that performance monitoring is typically part of an engineering program, which would not be part of water chemistry. In most cases, functional and performance testing verifies that component active functions can be accomplished and as such would be included as part of maintenance rule (10 CFR 50.65) programs. Passive intended functions of pumps, heat exchangers and other components will be adequately managed by the Water Chemistry Control – Closed Cooling Water Program and One-time Inspection Program through monitoring and control of water chemistry parameters and verification of the absence of aging effects.

Exception 4. In the LRA, the applicant took the following exception to the GALL Report program element “acceptance criteria”: “NUREG-1801 recommends system and component performance test result evaluations. The IPEC Water Chemistry Control - Closed Cooling Water Program does not perform performance and functional testing.”

The staff noted that the discussion of this exception in Section B.1.40 of the LRA includes a footnote, which states the following:

> While NUREG-1801, Section XI.M21, Closed Cycle Cooling Water System endorses EPRI report TR-107396 for performance and functional testing guidance, EPRI report TR-107396 does not recommend that equipment performance and functional testing be part of a water chemistry control program. This is appropriate since monitoring pump performance parameters is of little value in managing effects of aging on long-lived, passive CCW system components. Rather, EPRI report TR-107396 states in Section 5.7 (Section 8.4 in EPRI report 1007820) that performance monitoring is typically part of an engineering program, which would not be part of water chemistry. In most cases, functional and performance testing verifies that component active functions can be accomplished and as such would be included as part of maintenance rule (10 CFR 50.65) programs. Passive intended functions of pumps, heat exchangers and other components will be adequately managed by the Water Chemistry Control – Closed Cooling Water Program and One-time Inspection Program through monitoring and control of water chemistry parameters and verification of the absence of aging effects.

The applicant stated that the LRA indicates that Water Chemistry Control - Closed Cooling Water Program attributes 3, 4, 5, and 6 have an exception to the GALL Report. In all four cases, the exception is due to the fact that the GALL Report recommends the use of performance and functional testing to ensure acceptable function of the closed cooling water systems, while the

IPEC Water Chemistry Control - Closed Cooling Water Program does not include performance and functional testing. The exception is the same regardless which revision of the EPRI guideline is used because neither revision of the EPRI guideline recommends that equipment performance and functional testing should be part of a water chemistry program. Rather, the EPRI reports state (Section 5.7 in EPRI report TR-107396 and Section 8.4 in EPRI report 1007820) that performance monitoring is typically part of an engineering program, which would not be part of water chemistry.

The staff asked the applicant for additional information to justify not performing testing and functional inspections as part of this AMP (Audit Item 97). In response, by letter dated March 24, 2008, the applicant stated that EPRI report TR-107396 does not recommend that equipment performance and functional testing be part of a water chemistry control program. This is appropriate since monitoring pump performance parameters is of little value in managing effects of aging on long-lived, passive closed cooling water system components. Rather, EPRI report TR-107396 states in Section 5.7 (Section 8.4 in EPRI report 1007820) that performance monitoring is typically part of an engineering program, which would not be part of water chemistry. In most cases, functional and performance testing verifies that component active functions can be accomplished and as such would be included as part of Maintenance Rule (10 CFR 50.65) programs. Passive intended functions of pumps, heat exchangers and other components will be adequately managed by the Water Chemistry Control – Closed Cooling Water Program and One-time Inspection Program through monitoring and control of water chemistry parameters and verification of the absence of aging effects.

In addition, the applicant referenced its response to the staff's request for technical justification for not including visual inspection in the program. The applicant stated in the response that the Water Chemistry Control - Closed Cooling Water Program is a preventive program. EPRI Report TR-1007820 refers to inspections performed in conjunction with maintenance activities, which are not specifically included as part of this program. However, components cooled by closed cooling water systems are routinely inspected as part of an eddy current inspection program. These heat exchangers receive a visual inspection in addition to eddy current testing that would detect aging effects and confirm the effectiveness of the Water Chemistry Control-Closed Cooling Water Program. Some of the heat exchangers receiving visual inspections include:

- IP2 and IP3 Closed Cooling Water 21/22CCHX and ACAHCC1/2
- IP2 and IP3 Instrument Air Closed Cooling Water 21/22CWHX and SWM-CLC 31/32-HTX
- IP2 and IP3 EDG Jacket Water Coolers 21/22/23EDJC and EDG-31/32/33-EDGJWHTX
- IP2 Conventional Closed Cooling 21/22THCCSHX
- IP3 Turbine Hall Closed Cooling SWT-CLC-31/32-HTX

In addition to these completed inspections, LRA Section B.1.27, One-Time Inspection, describes future inspections planned to verify effectiveness of the water chemistry control programs to ensure that significant degradation is not occurring and component intended function is maintained during the period of extended operation. This will include areas most susceptible to corrosion such as stagnant areas.

The staff reviewed EPRI Report TR-1007820 (Revision 1 to EPRI TR-107396) and determined that it does not recommend that performance and functional testing be part of the water chemistry control program. This engineering testing could be performed as part of another program. Usually, the Maintenance Rule (10 CFR 50.65) dictates the requirements of the performance and functional testing. The staff noted that a one-time inspection will be performed to verify the effectiveness of this program for managing aging in the closed loop cooling water systems in the scope of this program. The staff finds that the water chemistry control, monitoring, and inspection activities included in this program are adequate to manage the aging effects for which the program is credited without the need for performance and functional testing. SER Section 3.0.3.1.9 document the staff's evaluation of the One-Time Inspection Program. Based on the above, the staff finds these exceptions acceptable.

The staff reviewed the applicant's evaluation and confirmed that the applicant had incorporated EPRI TR-1007820 as the technical basis guideline for its B.1.40 aging management program. The staff determined that the use of EPRI TR-1007820 provides guidance that is consistent with the recommendations in GALL AMP XI.M21, along with more detail on the various water treatment methods used at nuclear power plants, as well as control and diagnostic parameters, monitoring frequencies, operating ranges, and action levels. Therefore, the staff finds the use of EPRI TR-1007820 as the basis for this program acceptable.

Based on the above review, the staff finds the applicant's exceptions acceptable.

Enhancement 1. In the LRA and in Amendment 1 to the LRA, Attachment 2, Commitment Item 28, dated December 18, 2007, the applicant committed to implement the following enhancement to program elements "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria": "IP2: Revise appropriate procedures to maintain water chemistry of the SBO/Appendix R diesel generator cooling system per EPRI guidelines."

The enhancement is necessary to expand the scope of the program to ensure that it bounds all the components within the scope of license renewal. The enhancement does not change program content/criteria.

The staff determined that the applicant's enhancement will add water chemistry control, monitoring, and inspection activities for the IP2 SBO/Appendix R diesel generator cooling system. The enhancement will ensure that water chemistry control program activities are provided for all components on the site within the scope of the Water Chemistry control – Closed Cooling Water Program which is consistent with the recommendations in the GALL Report. On this basis, the staff finds this enhancement acceptable.

Enhancement 2. In the LRA and in Amendment 1 to the LRA, Attachment 2, Commitment Item 28, dated December 18, 2007, the applicant committed to implement the following enhancement to program elements "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria": "IP2: Revise appropriate procedures to maintain the security generator cooling water system pH within limits specified by EPRI guidelines."

The enhancement is necessary to expand the scope of the program to ensure that it bounds all the components within the scope of license renewal. The enhancement does not change program content/criteria.

The staff determined that the applicant's enhancement will add water chemistry control, monitoring, and inspection activities for the IP2 security diesel generator cooling system cooling water pH. The enhancement will ensure that water chemistry control program activities are provided for all components on the site within the scope of the Water Chemistry control – Closed Cooling Water Program which is consistent with the recommendations in the GALL Report. On this basis, the staff finds this enhancement acceptable.

Enhancement 3. In the LRA and in Amendment 1 to the LRA, Attachment 2, Commitment Item 28, dated December 18, 2007, the applicant committed to implement the following enhancement to program elements "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria": "IP3: Revise appropriate procedures to maintain security generator cooling water pH within limits specified by EPRI guidelines."

The enhancement is necessary to expand the scope of the program to ensure that it bounds all the components within the scope of license renewal. The enhancement does not change program content/criteria.

The staff determined that the applicant's enhancement will add water chemistry control, monitoring, and inspection activities for the IP3 security diesel generator cooling system cooling water pH. The enhancement will ensure that water chemistry control program activities are provided for all components on the site within the scope of the Water Chemistry control – Closed Cooling Water Program which is consistent with the recommendations in the GALL Report. On this basis, the staff finds this enhancement acceptable.

Operating Experience. LRA Section B.1.40 states that in June 2003 the applicant noted that the CCW corrosion inhibitor (molybdate concentration) had been out of specification 50 percent of the time since the new specification was issued in March 2003 due to dilution from water added to this system to compensate for leaks and work activities. Corrective action repaired the leaks and added chemicals to restore the molybdate concentration to specification. Detection of out-of-specification conditions and corrective action prior to loss of intended function assure continued program effectiveness in managing aging effects for passive components. Subsequently, corrosion inhibitor concentration has been satisfactory.

A QA audit of the plant chemistry program in August 2003 found the control of closed cooling water chemistry at IP2 as one of the specific areas improved since the last audit. Continuous program improvement assures continued program effectiveness in managing loss of component material.

Reports of closed cooling water chemistry control indicator (corrosion inhibitor and hardness) show that IP2 and IP3 CCW chemistry was within specification throughout 2006 except for part of May when the IP2 system was in maintenance status during refueling outage 2R17. Adherence to chemistry specifications assures continued program effectiveness in managing component aging effects.

The staff's review of operating experience indicates that this program has been effective in managing aging effects.

The staff confirmed that the "operating experience" program element satisfies the criteria in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.39 and A.3.1.39, the applicant provided the UFSAR supplement for the Water Chemistry Control - Closed Cooling Water Program. By letter dated June 12, 2009, the applicant amended LRA Section A.2.1.39 to add the IP2 instrument air system to the scope of the program. The staff reviewed these sections, as amended, and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

The applicant stated in the LRA that this program will be implemented prior to the period of extended operation (Commitment 28).

Conclusion. On the basis of its audit and review of the applicant's Water Chemistry Control - Closed Cooling Water Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report, are consistent. In addition, the staff reviewed the exceptions and their justifications and determines that the program is adequate to manage the aging effects for which it is credited. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program 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 Water Chemistry Control - Primary and Secondary Program

Summary of Technical Information in the Application. LRA Section B.1.41 describes the existing Water Chemistry Control - Primary and Secondary Program as consistent with GALL AMP XI.M2, "Water Chemistry," with enhancement.

The Water Chemistry Control - Primary and Secondary Program manages aging effects caused by corrosion and cracking mechanisms. The program monitors and controls reactor water chemistry based on EPRI TR-105714, Revision 5, "Pressurized Water Reactor Primary Water Chemistry Guidelines," and TR-102134, Revision 6, "Pressurized Water Reactor Secondary Chemistry Guidelines."

Both the EPRI primary and secondary water chemistry guidelines distinguish clearly between "control parameters" and "diagnostic parameters." Strict adherence to control parameters is expected whereas diagnostic parameters are suggested but can be plant-specific. Deviations from EPRI recommended diagnostic parameters are not exceptions to the GALL Report.

The GALL Report states that the water chemistry control is based on EPRI Reports TR-105714, Revision 3, for primary water chemistry, and TR-102134, Revision 3, for secondary water chemistry. Entergy has adopted TR-105714, Revision 5, renumbered by EPRI to Report 1002884, and TR-102134, Revision 6, renumbered by EPRI to Report 1008224.

The Revision 5 changes to TR-105714 consider the most recent operating experience and laboratory data and reflect increased emphasis on plant-specific optimization of primary water chemistry to address individual plant circumstances and the impact of the NEI steam generator initiative, NEI 97-06, which requires utilities to meet the intent of the EPRI guidelines. EPRI TR-105714, Revision 5, attempts to distinguish clearly between prescriptive and non-prescriptive guidance.

Revision 4 of TR-102134 was issued in November 1996 with increased depth of detail of the corrosion mechanisms affecting steam generators and the balance of plant and additional guidance on how to integrate these and other concerns into the plant-specific optimization process. Revision 5 provides additional details of plant-specific optimization and clarifies which EPRI guidelines are mandatory under NEI 97-06. Revision 6 provides further details on how best to integrate these guidelines into a plant-specific chemistry program while complying with NEI 97-06 and NEI 03-08, "Guideline for the Management of Materials Issues."

Future revisions of the EPRI primary and secondary water chemistry guidelines will be adopted as required commensurate with industry standards. The One-Time Inspection Program for Water Chemistry utilizes inspections or NDEs of representative samples to verify whether the Water Chemistry Control - Primary and Secondary Program has been effective in managing aging effects.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Water Chemistry Control - Primary and Secondary Program to verify consistency with GALL AMP XI.M2. Details of the staff's audit of this AMP are documented in the Audit Report. As documented in the report, the staff found that the Water Chemistry Control - Primary and Secondary Program elements "scope of program, preventive actions," "detection of aging effects," and "monitoring and trending," are consistent with the corresponding elements in GALL AMP XI.M2. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited.

The staff reviewed portions of the Water Chemistry Control – Primary and Secondary Program for which the applicant claims consistency with the GALL Report and documented an audit summary evaluation of this AMP in the Audit Report. Furthermore, the staff concludes that the applicant's Water Chemistry Control – Primary and Secondary Program reasonably assures management of aging effects so components crediting this program can perform intended functions consistent with the CLB during the period of extended operation. The staff finds the applicant's Water Chemistry Control – Primary and Secondary Program acceptable as consistent with the recommended GALL AMP XI.M2, "Water Chemistry with the enhancement as described:

Enhancement. In the LRA, the applicant committed to implement the following enhancement to program elements "parameters monitored or inspected" and "acceptance criteria": "[t]he 'parameters monitored or inspected,' will be enhanced to revise appropriate procedures to test sulfates monthly in the RWST for IP2 and "acceptance criteria," with a limit of < 150 ppb."

During the audit and review, the staff asked the applicant why the enhancement is being made for IP2 but not for IP3 (Audit Item 99). By letter dated December 18, 2007, the applicant stated that consistent with EPRI TR-105714, Rev. 5 recommendations, IP3 currently monitors RWST sulfates monthly with a limit of < 150 ppb. IP2 has not incorporated this recommendation and an enhancement is required. Thus, the enhancement does not apply to IP3. The staff finds that this enhancement is acceptable because it will follow the EPRI guidance that is recommended in the

GALL Report. It is also acceptable that it does not apply to IP3 because it was previously instituted for IP3 consistent with the EPRI guidance.

Operating Experience. LRA Section B.1.41 states that a QA audit of the primary and secondary plant chemistry program in August 2003 noted that monitoring and processing requirements for primary and secondary water chemistry complied with both IP2 and IP3 technical specifications, implementing procedures, and the IP3 technical requirements manual. In addition, the chemistry processes effectively implemented industry (e.g., EPRI and INPO) guidelines designed to extend the operating lives of primary and secondary systems and components. Continuous program improvement through adoption of evolving industry guidelines assures continued program effectiveness in managing the effects of aging on plant components.

During the audit and review, the staff asked the applicant about the frequency of the QA audits of the primary and secondary plant chemistry program. The applicant replied that the QA audits are conducted every two years. An extra audit was conducted in 2006 in addition to the regular audit in 2005 in order to adjust the audits to even years for scheduling purposes. These audits were reviewed by the staff during the onsite audit.

The staff confirmed that the “operating experience” program element satisfies the criterion defined in the GALL Report and in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.40 and A.3.1.40, the applicant provided the UFSAR supplement for the Water Chemistry Control - Primary and Secondary Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

The applicant stated that the program enhancements will be implemented prior to entering the period of extended operation (Commitment 29).

Conclusion. On the basis of its audit and review of the applicant’s Water Chemistry Control - Primary and Secondary 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 prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3 Programs Not Consistent with or Not Addressed in the GALL Report

3.0.3.3.1 Boral Surveillance Program

Summary of Technical Information in the Application. LRA Section B.1.4 describes the existing Boral Surveillance Program as a plant-specific program.

The Boral Surveillance Program verifies whether the Boral neutron absorbers in the spent fuel racks maintain the validity of the criticality analysis in support of the rack design. The program relies on representative coupon samples mounted in surveillance assemblies in the spent fuel pool to monitor performance of the absorber material without disrupting the integrity of the storage system. Surveillance assemblies are removed from the spent fuel pool on a prescribed schedule for measurement of physical and chemical properties to assess the stability and integrity of the Boral in the storage cells. This program applies to IP3 only because Boral is not used for criticality control of IP2 spent fuel.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in LRA Section B.1.4 on the applicant's demonstration of the Boral Surveillance Program to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

The staff reviewed the Boral Surveillance Program against the AMP elements found in the SRP-LR Section A.1.2.3, and in SRP-LR Table A.1-1, focusing on how the program manages aging effects through the effective incorporation of 10 elements. Specifically, the staff reviewed the following seven program elements of the applicant's program: (1)"scope of the program," (2) "preventive actions," (3) "parameters monitored or inspected," (4) "detection of aging effects," (5) "monitoring and trending," (6) "acceptance criteria," and (10) "operating experience."

The applicant indicated that program elements (7) "corrective actions," (8) "confirmation process," and (9) "administrative controls" are parts of the site-controlled QA program. The staff's evaluation of the QA program is in SER Section 3.0.4. Evaluation of the remaining seven elements follows:

(1) Scope of the Program - LRA Section B.1.4 states that, "the Boral Surveillance Program includes all Boral in the IP3 spent fuel pool. The IP2 spent fuel pool design does not rely on Boral for criticality control."

The staff confirmed that the "scope of the program" program element satisfies the guidance in SRP-LR Section A.1.2.3.1, since the staff confirmed that Boral was only used in IP3 spent fuel pool and IP2 uses Boraflex. Therefore, the staff finds this program element acceptable.

(2) Preventive Actions - LRA Section B.1.4 states that, "this is an inspection program and no actions are taken as part of this program to prevent or mitigate aging degradation."

The staff confirmed that the "preventive actions" program element satisfies the guidance in SRP-LR Section A.1.2.3.2 since IP3 has a condition monitoring program. Therefore, the staff finds this program element acceptable.

(3) Parameters Monitored or Inspected - LRA Section B.1.4 states that, the program monitors changes in the following physical properties of the Boral material.

- neutron attenuation
- blister size, thickness, and location
- dimensional measurements (length, width, shape, and thickness)
- specific gravity and density

The staff confirmed that the "parameters monitored or inspected" program element satisfies the guidance in SRP-LR Section A.1.2.3.3. The staff considers this program element acceptable because experience has shown that Boral degradation in the SFP environment occurs slowly and can be detected in the early stages by the methods proposed. The measurements of neutron attenuation, physical distortion, and weight change would detect coupon degradation that would precede a loss of functionality in the Boral panels (neutron absorption and fuel assembly spacing). Moreover, unacceptable coupon results would initiate an engineering evaluation and, if considered necessary, direct testing of the storage racks (i.e. blackness testing).

(4) Detection of Aging Effects - LRA Section B.1.4 states that "the program monitors representative coupon samples located in the spent fuel pool to determine the condition of the absorber material without disrupting the integrity of the storage system. At specified intervals, the program measures certain physical and chemical properties of removed sample coupons. From this data, the stability and integrity of the Boral in the storage cells are assessed."

The staff confirmed that the "detection of aging effects" program element satisfies the guidance in SRP-LR Section A.1.2.3.4 since the staff considers the program to collect data from representative coupon samples to assess for stability and integrity of Boral to be acceptable for detection of aging effects. Therefore, the staff finds this program element acceptable.

(5) Monitoring and Trending - LRA Section B.1.4 states that "neutron attenuation tests are trended to ensure that slow degradation has not occurred. Observable loss in neutron attenuation ability, if any, is projected to determine when neutron attenuation may fall below acceptance criteria. Size and weight measurements determine the extent of shrinkage or loss of material. This data is trended for indications of degradation. Blister shape and size are recorded and trended to determine whether new blisters are forming, the rate of growth of existing blisters, and the rate of increase in blister thickness. As blister thickness increases, it may become necessary to evaluate whether potential fuel cell deformation is a risk due to blister growth."

The staff confirmed that the "monitoring and trending" program element satisfies the guidance in SRP-LR Section A.1.2.3.5. The staff finds this program element acceptable because the applicant monitors and trends parameters that would indicate degradation.

(6) Acceptance Criteria - LRA Section B.1.4 states that "of the measurements to be performed on the Boral, the most important are neutron attenuation measurements and dimensional measurements. Acceptance criteria for these measurements are as follows.

- Neutron attenuation testing and B-10 areal density is equal to or greater than the B-10 gm/cm^2 nominal density assumed in the criticality analysis (0.02 g/cm^2)
- Blisters are unacceptable if blister size and shape projected to the next inspection may subsume the available space between the fuel assembly and the cell wall."

In RAI B.1.4, dated December 7, 2007, the staff requested that the applicant provide additional details on the Boral Surveillance Program in regards to the neutron attenuation testing and the acceptance criteria.

In its response, by letter dated January 4, 2008, the applicant provided the following information:

- K_{eff} <0.95 is the margin to criticality used in the criticality analyses. Use of Keff <0.95 as the margin to criticality acceptance criteria is consistent with NUREG 0800.
- IP3 Boral coupon surveillance results to date have not identified any loss of neutron absorption capability between surveillance periods such that the current criterion remains acceptable for use. This is consistent with industry experience.
- IP3 has sufficient Boral coupon samples to maintain the sampling frequency through the period of extended operation.

Based on the applicant's response to the RAI describing the Boral Surveillance Program, the staff finds the applicant's response to the RAI B.1.4 acceptable. The staff's concern in RAI B.1.4 is resolved.

The staff confirmed that the "acceptance criteria" program element satisfies the guidance in SRP-LR Section A.1.2.3.6 since IP3 provided specific values for the acceptance criteria which would provide reasonable assurance that corrective actions could be taken before loss of functionality would occur. The staff finds this program element acceptable.

(10) Operating Experience - LRA Section B.1.4 states that results of an inspection of coupon samples in 2002 showed no significant degradation of Boral material. A review of this program in 2004 addressed the Seabrook Part 21 issue on Boral coupon blistering (NRC21-031006 Part 21) and led to revision of the procedure for IP3 Boral examinations to test in the next inspection (2007) the same full-length Boral sample tested in the last inspection (2002) to allow direct measurement of blister growth and to determine whether the Boral blisters have reached equilibrium.

The applicant stated that its program is based on the NUREG-1801 program description, which in turn is based on industry operating experience. Such operating experience assures continued effectiveness of the Boral Surveillance Program in managing loss of Boral neutron absorber material.

The staff confirmed that the "operating experience" program element satisfies the guidance in SRP-LR Section A.1.2.3.10, since the operating experience supports the conclusion that the Boral Surveillance Program is effective in managing the loss of Boral neutron absorber material. The staff finds this program element acceptable.

<u>UFSAR Supplement</u>. In LRA Section A.3.1.3, the applicant provided the UFSAR supplement for the Boral Surveillance Program. The staff reviewed this section and finds the UFSAR supplement information an adequate summary description of the program, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its technical review of the applicant's Boral Surveillance Program, the staff concludes that the applicant has demonstrated that effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and concludes that it provides an adequate summary

description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.2 Containment Inservice Inspection Program

Summary of Technical Information in the Application. LRA Section B.1.8, as amended by letter dated June 11, 2008, describes the existing Containment Inservice Inspection Program as a plant-specific program.

The applicant states that the Containment Inservice Inspection Program encompasses ASME Section XI Subsection IWE and IWL requirements as modified by 10 CFR 50.55a. The IP2 program uses the ASME Boiler and Pressure Vessel Code, Section XI, 2001 Edition, through 2003 Addenda. The IP3 program uses the ASME Boiler and Pressure Vessel Code, Section XI, 1998 Edition, no addenda. Every 10 years, each unit's program is updated to the latest ASME Section XI code edition and addenda approved in 10 CFR 50.55a. Visual inspections for IWE of surfaces for evidence of flaking, blistering, peeling, discoloration, and other signs of distress monitor loss of material of the steel containment liners and their attachments, containment hatches and airlocks, moisture barriers, and pressure-retaining bolting. Visual inspections for IWL monitor structural concrete surfaces for evidence of leaching, erosion, voids, scaling, spalls, corrosion, cracking, exposed reinforcing steel, and detached embedment. The applicant also states that the IP2 and IP3 containments are reinforced concrete structures that do not utilize a post-tensioning system; therefore, IWL post-tensioning requirements do not apply.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in LRA Section B.1.8 on the applicant's demonstration of the Containment Inservice Inspection Program to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

The staff noted that the intent in writing GALL Report, Volume 2 Chapter XI was to enable an applicant to take credit for an existing mandated inspection program with minimal effort (i.e., simply identify and explain exceptions and enhancements). Entergy has identified AMP B.1.8 - Containment Inservice Inspection as being plant-specific. The staff reviewed LRA Section B.1.8 and concluded that the 10-element evaluation does not identify any differences from GALL AMPs XI.S1 (IWE) and XI.S2 (IWL). In an audit question, Entergy was requested to document an element-by-element comparison of LRA AMP B.1.8 to GALL AMPs XI.S1 and XI.S2, identifying and explaining all exceptions and enhancements to the GALL AMPs (Audit Item 26).

By letter dated December 18, 2007, Entergy indicated that the attributes of the program are compared to the ten elements of an aging management program for license renewal as described in SRP-LR, Table A.1-1. Entergy decided to describe the Containment ISI Program as a plant-specific program rather than comparing it to the GALL Report AMPs XI.S1 and XI.S2. Entergy indicated that this was done because the GALL Report programs contain many ASME Section XI table and section numbers which change with different versions of the code. Because of this, comparison with the GALL Report programs would generate many exceptions and explanations. Also, the applicable edition of the Code during the period of extended operation will be different than the edition referenced in the GALL Report.

Currently, the GALL AMPs for concrete containment, XI.S1 (for steel elements) and XI.S2 (for concrete elements) provide acceptable programs for the aging management of the containments. Using these AMPs avoids performing extensive reviews with many questions to properly evaluate the plant-specific programs. Thus, if a proposed plant-specific AMP for containments is credited, then a detailed review would be required where many items beyond those identified in the XI.S1 and XI.S2 AMPs will need to be identified. GALL AMPs XI.S1 and XI.S2 were developed based on the known provisions contained in the editions of the ASME Code, Section XI, Subsections IWE and IWL that are referenced. If a different edition of the Code is relied on and/or exceptions are taken with respect to the guidance in the GALL AMPs XI.S1 and XI.S2, then justification is needed to demonstrate adequacy. The need for additional justification is explained in the footnote to the XI.S1 and XI.S2 AMPs in GALL. This footnote states that "An applicant may rely on a different version of the ASME Code, but should justify such use." This applies to differences between the plant-specific program and the GALL XI.S1 and XI.S2 AMPs.

In the case of GALL AMPs XI.S1 and XI.S2, the acceptable code editions of Subsections IWE and IWL are those from the 1992 edition of the ASME Code, Section XI, including the 1992 Addenda, through the 2001 Code, and the 2002 and 2003 Addenda. The IP2 program uses the ASME Boiler and Pressure Vessel Code, Section XI, 2001 Edition, 2003 Addenda. The IP3 program uses the ASME Boiler and Pressure Vessel Code, Section XI, 1998 Edition, no Addenda. Every 10 years, each unit's program is updated to the latest ASME Section XI code edition and addenda approved by the Nuclear Regulatory Commission in 10 CFR 50.55a." Therefore, the editions of the Code that Entergy is using, for both IP2 and IP3, are consistent with those accepted by GALL AMPs XI.S1 and XI.S2. If, as stated in the Entergy response, there are numerous exceptions that would need to be explained, then the staff needs to be informed, in order to evaluate the adequacy of the Containment Inservice Inspection Program.

The concern noted in the Entergy response to the audit question, that the applicable edition of ASME Code, Section XI during the period of extended operation will be different than the edition referenced in the current GALL Report, is addressed in the footnote to GALL AMPs XI.S1 and XI.S2. The footnote states that "An applicant may wish to refer to the [statement of considerations] SOC for an update of 10 CFR 50.55a, to justify use of a more recent edition of the Code."

Entergy formally submitted Amendment 1 to the LRA on December 18, 2007. Under Audit Item 26, Entergy presented an element-by-element comparison to GALL AMPs XI.S1 and XI.S2. On the basis of this comparison, as discussed below, the staff finds the applicant's plant-specific Containment Inservice Inspection Program to be consistent with the GALL report.

In accordance with Entergy's decision to identify the Containment Inservice Inspection Program as a plant-specific AMP, the staff reviewed the Containment Inservice Inspection Program against the AMP elements found in the GALL Report, in SRP-LR Section A.1.2.3, and in SRP-LR Table A.1-1, focusing on how the program manages aging effects through the effective incorporation of 10 elements [(1) "scope of the program," (2) "preventive actions," (3) "parameters monitored or inspected," (4) "detection of aging effects," (5) "monitoring and trending," (6) "acceptance criteria," (7) "corrective actions," (8) "confirmation process," (9) "administrative controls," and (10) "operating experience"].

The applicant indicated that program elements (7) "corrective actions," (8) "confirmation process," and (9) "administrative controls" are parts of the site-controlled QA program. The staff's evaluation of the QA program is in SER Section 3.0.4. Evaluation of the remaining seven elements follows:

(1) Scope of the Program - LRA Section B.1.8 states that the Containment Inservice Inspection Program, under ASME Section XI Subsection IWE, manages aging effects for the containment liners and integral attachments including connecting penetrations and parts forming the leak tight boundary. The applicant further states that Containment Inservice Inspection Program, under ASME Section XI Subsection IWL provides confirmation that the effects of aging on the reinforced concrete containment walls, domes, and basemats will not prevent the performance of intended functions consistent with the CLB through the period of extended operation.

The staff confirmed that the "scope of the program" program element satisfies the guidance in SRP-LR Section A.1.2.3.1. The staff finds this program element acceptable.

(2) Preventive Actions - LRA Section B.1.8 states that the Containment Inservice Inspection Program is a monitoring program that does not include preventive actions. The staff concurs that this is a monitoring program, and no preventive actions are required.

The staff confirmed that the "preventive actions" program element satisfies the guidance in SRP-LR Section A.1.2.3.2. The staff finds this program element acceptable.

(3) Parameters Monitored or Inspected - LRA Section B.1.8 states that visual inspections for IWE monitor loss of material of the steel containment liner and its attachments by inspecting the surface for evidence of flaking, blistering, peeling, discoloration, and other signs of distress. The applicant also states that visual inspections for IWL monitor concrete surfaces for evidence of leaching, erosion, voids, scaling, spalls, corrosion, cracking, exposed reinforcing steel, and detached embedment.

In RAI B.1.8-1 dated December 7, 2007, the staff requested that the applicant provide additional details on the condition monitoring of protective coatings in containment. In particular, the staff requested a description of the coating inspections performed on surfaces that are not included in the IWE program.

By letter dated January 4, 2008, which was further clarified during telephone conference calls held on February 7, 2008, and March 7, 2008, the applicant stated that the condition of the protective coatings on metal surfaces at IP, other than the containment liner, is monitored by Structures Monitoring Program. The Structures Monitoring Program governs monitoring the condition of structures or components of structures, including the condition of their protective coatings, as required by 10 CFR 50.65, the Maintenance Rule.

The applicant further explained that the structures are inspected every 5 years and normally inaccessible areas are inspected every 10 years. An inaccessible area is an area that requires destructive removal of a barrier for access. The containment liner insulation is also considered a barrier such that the liner plate behind it is classified as inaccessible. The scope of the inspections includes visual inspection of the coated surfaces for signs of degradation (blistering, peeling, flaking, pinholes, rusting, splitting, and discoloration). The degradation observed during the inspections is evaluated to determine if the current condition is acceptable or further monitoring or corrective actions are necessary. Industry codes and standards including the Maintenance Rule, ASME Section XI, and building codes are used to perform these evaluations and make determinations as to whether or not the structures are capable of performing their intended functions. A structure is classified as acceptable if it is capable of performing its structural functions, including protection or support of safety-related equipment.

The inspections are performed by inspection engineers under the direction of the responsible engineer. The responsible engineer is a degreed civil/structural engineer with at least 10 years of related experience and a registered professional engineer. The responsible engineer and inspection engineers must be knowledgeable in the design, evaluation, and performance requirements of structures. The inspection engineers must be qualified to perform visual examination either directly or remotely to detect evidence of degradation.

The applicant clarified that protective coatings are not relied upon to manage the effects of aging for structures in License Renewal. The existing 10 CFR 50.65 Maintenance Rule Program includes monitoring the condition of coatings and they will continue to be monitored under that program during the period of extended operation.

Additionally the applicant stated that, in response to Generic Safety Issue (GSI)-191, "Assessment of Debris Accumulation on PWR Sump Performance," the Civil/Structural group visually inspects coatings in the vapor containment building during refueling outages. The frequency of the inspection will be at least once every two years or every cycle during the refueling outage. Adverse conditions will be resolved or evaluated as acceptable prior to exiting the refueling outage.

Based on the applicant's response to the RAI describing the division in responsibilities between the Structures Monitoring Program and the Maintenance Rule Program, the staff finds the applicant's response to the RAI B.1.8-1 acceptable. The staff's concern in RAI B.1.8-1 is resolved.

The staff confirmed that the "parameters monitored or inspected" program element satisfies the guidance in SRP-LR Section A.1.2.3.3. The staff finds this program element acceptable.

(4) Detection of Aging Effects - LRA Section B.1.8 states that the primary inspection method for the steel containment liner and its integral attachments is general visual examination. Components in examination category E-A receive general visual examination or VT-3. Painted or coated areas are examined for evidence of flaking, blistering, peeling, and discoloration. Non-coated areas are examined for evidence of cracking, discoloration, wear, pitting, corrosion, gouges, and surface irregularities. Components in examination category E-C receive an augmented visual or volumetric examination in accordance with IWE Table 2500-1. The applicant also states that the primary inspection method for the concrete containment shell is a general visual examination in accordance with IWL-2500. Detailed visual examinations are performed to provide sufficient data to conduct an acceptance review when conditions exceeding the screening criteria are noted.

The staff noted that the IP2 and IP3 containments have a somewhat unique design feature: thermal insulation on the steel liner plate, at the lower elevations of the cylindrical containment wall. In both UFSARs, this insulation is credited with limiting the liner temperature increase to 80 °F during a design basis accident. Both UFSARs state that the insulation is removable, to permit periodic inspection of the containment liner plate. In Audit Item 27, the staff asked Entergy to:

(1) Identify the AMP and describe the specific inspections performed, to ensure that this insulation will continue to perform its intended function.

(2) Describe the plant-specific operating experience related to removal of this insulation and inspection of the containment liner plate normally covered by the insulation. How does the condition of the normally insulated liner plate surface compare to the condition of the normally uncovered liner plate surface? Has augmented inspection, per Category E-C, been necessary?

In its response, dated December 18, 2007, Entergy stated:

> (1) As noted in LRA Table 3.5.2-1, the liner plate insulation jacket has no aging effect, and therefore does not require aging management.
>
> (2) IP2 and IP3 have approximately 20% of the liner inaccessible due to the insulation at the lower elevations of the containment. At the 46' Elevation, a caulking sealant, used as a moisture barrier, is installed at the junction of the bottom edges of the insulation panels and the floor to prevent moisture from reaching the steel liner. When performing a visual examination of the liner, the insulation covering portions of the containment liner is not removed. The IWE examination includes inspection of the moisture barrier to ensure that it has not degraded. IP2 and IP3 will remove insulation during the required IWE examinations if insulation removal is required to meet the requirements in Table IWE-2500-1.
>
> During the IWE first interval for IP2, corrosion was discovered on the liner during the first period (April 2000) containment inservice inspection. The corrosion existed in the portion of the liner where it is abutted by the fill slab that covers the base mat liner. A number of inspections, investigations, and evaluations were performed to determine the acceptability of the liner to perform its design function. The inspection found several areas where the moisture barrier was missing or not properly bonded between the floor slab and insulation. The degradation of the moisture barrier raised a concern relative to the condition of the liner. In order to address these concerns, IP2 selected nine (9) panels of the liner insulation for removal to facilitate augmented inspection, per Category E-C. During the removal and re-installation of these insulation panels, the opening covers are re-sealed with the caulking sealant in order to re-establish the moisture barrier.

Entergy further stated that when the insulation was removed, minor corrosion (light rust) was noted. Thickness readings were taken with no significant wall loss detected. As a result of three consecutive inspections of the nine (9) panel areas, the containment liner plate in these areas was found dry and the corrosion inactive, and the liner plate was well within the required containment liner thickness. This augmented exam was completed during the last IP2 Containment ISI interval. Entergy concluded that the IP2 liner will perform its intended function and is within acceptance limits for continued operation.

For part (a) of Entergy's response, the staff's evaluation concludes that there is no aging effect requiring an aging management program for insulation encapsulated in a stainless steel jacket and subject to an "air – indoor uncontrolled" environment. The staff accepts Entergy's AMR results.

For part (b) of Entergy's response, the staff concluded that additional information was needed before the evaluation could be completed. The staff subsequently determined, from review of Entergy documents during the audit, that insulation had been placed over the IP2 liner area that had been damaged (localized permanent deformation due to thermal expansion) by a feedwater line break in 1973. The damaged area is approximately 5' high and 50' around the circumference. Entergy has also treated this damaged area as inaccessible for inspection. While Entergy performed an evaluation at that time, which concluded that the permanent liner degradation would not compromise the integrity of the liner, the staff notes that the condition of the liner in the damaged area has not been examined for over 30 years.

In addition, as discussed previously, Entergy has detected some minor corrosion of the IP2 liner behind the insulation, at the juncture with the concrete floor slab. In discussions with Entergy, the staff expressed concern that similar corrosion may exist in IP3; however, Entergy has not examined the corresponding IP3 location.

Therefore, the staff requested that Entergy conduct a one-time inspection of the steel liner behind the insulation at 2 specific locations: (1) the damaged area of the IP2 steel liner; and (2) the IP3 steel liner at the juncture with the concrete floor slab, in order to confirm the absence of liner plate degradation behind thermal insulation.

The applicant provided a supplemental response to Audit Item 27 in Attachment 1 "Operating Experience – Structures" to Entergy letter dated August 14, 2008. In its response, the applicant stated that, in order to provide assurance that liner degradation is not occurring in the affected area, Entergy commits to remove insulation and perform a one-time inspection of a representative sample area of the IP2 containment liner affected by the 1973 event prior to entering the period of extended operation. Also, in order to provide further assurance that liner degradation is not occurring in the area at the juncture with the concrete floor slab on IP3, Entergy committed to perform a one-time inspection of sample locations of the IP3 containment liner at the juncture with the concrete floor slab, prior to entering the period of extended operation. These one-time inspections are documented as Commitment 35 in Regulatory Commitment List, Revision 5; Attachment 4 to Entergy letter dated August 14, 2008.

At the staff's request, the applicant has committed to perform the one-time inspections of representative samples of liner areas prior to entering the period of extended operation, to confirm the absence of any liner plate degradation behind thermal insulation. Any degradation that is detected would be dispositioned in accordance with the Containment Inservice Inspection Program, including reanalysis, repair or replacement, and fatigue analysis for IP2, if necessary. Based on this commitment, the staff considers the issue related to liner plate degradation behind thermal insulation to be resolved.

(5) Monitoring and Trending - LRA Section B.1.8 states that results are compared, as appropriate, to baseline data and other previous test results.

The staff confirmed that the “monitoring and trending” program element satisfies the guidance in SRP-LR Section A.1.2.3.5. The staff finds this program element acceptable.

(6) Acceptance Criteria - LRA Section B.1.8 states that results are compared, as appropriate, to baseline data, other previous test results, and acceptance criteria of ASME Section XI, Subsection IWE for evaluation of any evidence of degradation. Results are compared, as appropriate, to baseline data, other previous test results, and acceptance criteria of ASME Section XI, Subsection IWL for evaluation of any evidence of degradation.

The staff confirmed that the “acceptance criteria” program element satisfies the guidance in SRP-LR Section A.1.2.3.6. The staff finds this program element acceptable.

(10) Operating Experience - LRA Section B.1.8 states that results of the IWE containment inspection at IP2 in 2004 were satisfactory.

The applicant states that an IWE containment inspection at IP3 in 2005 detected minor surface corrosion classified as “acceptable” under the program definitions.

The applicant also states that an IWL inspection at IP2 in 2005 revealed 91 recordable indications reviewed by engineering. None of these indications, which were compared to the results of the 2000 inspection, represented a structural concern. An IWL inspection at IP3 in 2005 found minor spalling and other indications noted in the 2001 inspection with no signs of further degradation. Absence of degradation that could lead to failure, demonstrated through regular program inspections, assures effective program management of aging effects for passive components.

The applicant further states that a self-assessment of the Containment ISI program in October 2004 found all findings and recommendations from earlier EPRI assessments of the program evaluated and corrected. Detection of program weaknesses and subsequent corrective actions assure continued program effectiveness in managing component aging effects.

The staff noted that in 1973 a significant permanent deformation of the IP Unit 2 liner plate occurred at the penetration for feedwater line #22, as described in LRA Section 4.6. However, the operating experience element of AMP B.1.8 does not discuss this existing condition, nor the results of periodic inspections conducted under the Containment ISI Program. In Audit Item 30, the staff asked Entergy to:

(a) Describe in greater detail the event that resulted in the permanent liner plate deformation. When specifically did it occur? What was identified as the root cause? How was this corrected?

(b) Discuss the history of ISI of the permanently deformed liner plate, from 1973 to the present.

In its response, dated December 18, 2007, Entergy stated:

(a) The permanent IP2 liner plate deformation occurred on November 13, 1973 as a result of a break in the feedwater line to Steam Generator No. 22 inside the containment near the feedwater line penetration. The pipe break resulted in a slight bulge, which apparently was caused by the steam and water jet impingement. This was corrected by pressurizing the containment which caused the liner to move 5/8 of an inch at 15 psig and no further during pressurization to 47 psig. Also, a number of modifications were made to prevent water hammers in these lines and to improve the piping and liner ability to withstand such forces. These included rerouting the pipe layout, installing additional pipe supports, installing "J Tubes" to delay the draining of the feedwater rings, and installing additional insulation above the pipe break area around the inside of the containment. In addition, analyses were performed of the liner plate and pipe material, and some experimental verification was conducted.

(b) In 2004, general visual examinations were performed for all accessible areas of the containment liner, including penetrations and airlocks as part of the Containment Inservice Inspection Program. Some minor surface corrosion and/or coating deterioration were observed on the penetrations. Entergy concluded that this is general surface corrosion that did not result in any significant loss of material. A containment leak rate test at IP2 was completed satisfactorily in 2006.

Further staff evaluation of this condition is contained in the "Detection of Aging Effects" discussion above. Entergy has committed to inspect the damaged liner area, which was covered by insulation after the accident, to confirm the absence of liner degradation, prior to entering the period of extended operation.

The staff reviewed the discussion of operating experience for the existing, plant-specific Containment Inservice Inspection Program as given in the PBD. In a condition report, the staff noted that it stated, "The south side of the Containment dome in the alley between the Fan building and VC about 25 feet up is spalling in about 6-7 places. The rebar is exposed to the elements and is showing signs of rust. The openings into the concrete are about 12-14 inches."

IP2 Containment Spalling (Audit Item 361)

In Audit Item 361, the staff asked Entergy to provide additional details, including any commitments for augmented inspection during the period of extended operation. In its response, dated March 24, 2008, Entergy stated that this condition was first noted during the 2000 IWL inspection. The 2005 IWL inspection found little or no change from 2000. The spalls occur at locations where Cadweld™ sleeves have insufficient concrete cover, attributed to an original installation deficiency. Rusting is not active and spalls are in an area where the rebar stresses are low. Entergy indicated that Raytheon has evaluated the structural margins for the IP containments, and at the locations of the exposed rebar, there is sufficient margin to accommodate additional loss of material due to corrosion. The condition is being monitored under the IWL program. Remedial action will be taken if the spalls further degrade and affect structural integrity.

Entergy identified several inspection enhancements, beyond general visual inspection, that are being implemented to more accurately measure the extent and progress of degradation. However, there is no commitment to continue this augmented inspection during the period of extended operation. In follow-up discussions regarding Audit Item 361, the staff requested Entergy to (1) provide the technical basis why augmented inspection during the extended period of operation is not necessary; and (2) provide its rationale for not proactively precluding progression of the concrete spalls and rebar rust/corrosion during the period of extended operation, by taking reasonable action to remedy this condition.

The applicant provided its supplementary response in a letter dated August 14, 2008. In its response, the applicant stated:

> Concrete spalls on the containment were noted during the 2000 containment inservice inspection. In these areas, the exposed reinforcing steel is oxidized, forming a protective coating. These areas have been evaluated under the corrective action program. The evaluations have determined that the spalls occur at locations where cadweld sleeves have insufficient concrete cover. Cadweld splices have diameters larger than the bar and thus have the least amount of concrete cover. The spalled concrete locations are on the vertical cylinder wall of the containment precluding the possibility of standing water that could percolate through the concrete. The location on the vertical wall of containment precludes ready access to allow for repair of a condition determined to have no impact on the ability of the structure to perform its required function.
>
> The 2005 CII-IWL inspection found little or no change of the condition observed in 2000. The identified areas show no signs of corrosion staining or deterioration and no indication that the degradation is progressing.
>
> During the LRA review, Entergy committed to enhance the CII-IWL inspections during the period of extended operation through enhanced characterizing of the degradation (i.e., quantifying the dimensions of noted indications through the use of optical aids) (Ref. audit question 533). This better quantification will allow for more effective trending of degradation following future inspections. The enhancement includes obtaining critical dimensional data of degradation where possible through direct measurement or the use of scaling technologies for photographs, and the use of consistent vantage points for visual inspections. Implementation of this enhancement requires the continued use of optical aids to allow effective characterization of indications on the containment wall that are not accessible from the ground or from existing structures.
>
> While Entergy has observed no progression of the containment concrete spall and rebar corrosion conditions during the most recent periodic inspections, the enhanced measures for characterizing degradation during the period of extended operation provide an effective means to detect potential future progression of the degradation such that corrective action to remedy the condition can be taken prior to loss of the license renewal intended function. [Commitment 37]

The staff's evaluation of Entergy's supplemental response concluded that the applicant's commitment to use enhanced inspection techniques to better characterize and monitor the degradation is a positive step; however, the applicant had not committed to take remedial action to fix the degraded areas. Therefore, the staff determined that it needed additional clarification of how Entergy plans to implement aging management during the license renewal period.

In a telephone call with the applicant on September 3, 2008, the staff requested additional relevant information for the IP2 and IP3 containments on the existing design margins at the locations of observed degradation, identifying the specific locations and dimensions of the damage. By letter dated November 6, 2008, the applicant submitted a supplemental response to Audit Item 361, describing the design margins for the IP containment structures at the locations of existing concrete degradation. At the time of issuance of the SER with Open Items, the staff was in the process of reviewing the applicant's response. Thus, this issue was identified as Open Item 3.0.3.3.2-1.

In its response dated November 6, 2008, the applicant stated:

> Spalling of concrete has been observed on IP2 containment exterior surface. The affected areas are the vertical wall.
>
> The containment structure is designed to withstand seismic, wind, deadweight, pressure, and temperature forces caused by natural phenomena and accident conditions. In addition, the integrated leak rate test is periodically performed on the containment which imposes an internal nominal pressure of 47 psi.
>
> Margin is defined as the difference between the Code allowable forces/stresses and the actual forces/stresses in the structure caused by the most severe loading condition. Meeting the Code provides margin in the form of a safety factor that requires the design strength of the structure to be a multiple of the strength necessary to prevent failure under maximum load conditions. Over and above the safety factor established by meeting Code requirements is margin between actual strength and the strength required to just meet the Code.
>
> All areas of the spalled concrete on the containment structure exceed the strength required to meet Code requirements. The margin available over and above the Code requirements is shown in the following table. As the surface concrete is not credited for tensile strength of the structure, the spalling has no impact on the available margins.

Elevation (ft above ground)	Margin above Code allowable (%)	
	Vertical rebar	Horizontal rebar
191.0	51	32
117	58	38
64	52	51
45.7	37	100

Since the design of the IP3 containment is similar to the IP2 containment design, the margins developed for IP2 are applicable to IP3."

The applicant also tabulated the approximate location (elevation and azimuth), dimensions of spall and the design margin for each spalled area for IP2 and IP3 in its above response.

The staff reviewed the applicant's response dated November 6, 2008, and concluded that the staff required additional clarification before it could determine that the applicant's proposed aging management program for the period of extended operation is sufficient. This issue was identified as Open Item 3.0.3.3.2-1.

In an effort to resolve this open item, the staff issued follow-up RAI 3: Open Item 3.0.3.3.2-1 (Audit Question 361), dated April 3, 2009, which requested the following:

(a) The clarification for the IP containment spalling states: 'As the surface concrete is not credited for tensile strength of the structure, the spalling has no impact on the available margins.' The strength margins identified appear to be based on the nominal rebar dimensions, without any consideration for rebar degradation due to exposure and potential loss of bond between the concrete and the rebar. Explain how the existing degradation and design margin will be considered in performing periodic inspections to monitor degradation that would ensure that there is no loss of containment intended function during the period of extended operation.

(b) In the spent fuel pool discussion, in the letter dated November 6, 2008, the applicant stated: '[l]ittle or no corrosion was observed in the rebar except at a location in the wall where spalling had occurred exposing rebar to the elements. Analysis of the rust particles showed high chloride content and, low boron concentration indicating that rainwater was the primary cause of the observed corrosion.' The applicant is requested to provide the technical basis for the adequacy of the 5-year IWL frequency of inspection of the degraded areas of the IP containments during the period of extended operation, considering the possibility of an increased site-specific corrosion rate of the exposed rebar on the containments. This should include results of prior inspections, including any available comparative photos showing the progression of degradation.

By letter dated May 1, 2009, Entergy responded to follow-up RAI 3: Open Item 3.0.3.3.2-1 (Audit Question 361), stating as follows:

(a) As stated in Letter NL-08- 169, dated November 6, 2008, the existing surface concrete degradation and potential loss of bond between the concrete and the rebar has no impact on the ability of containment to perform its intended function during the period of extended operation. The design margins in containment are such that loss of one bar in every 4.5 feet in the vertical direction would not impact the ability of containment to perform its intended function.

The ISI-IWL inspections have confirmed that there has been no identified degradation that could result in loss of function of the containment structure (rebar and concrete) due to aging effects. Localized surface rust has been observed at containment areas where rebar has been exposed, but these visual inspection results show no discernable deviation of rebar dimensions from nominal. No degradation has been observed that indicates loss of bond for rebar that is not monitored directly.

As part of the IPEC corrective action program (i.e., program Element 7), if degradation is identified during inspections, the impact of the degradation on design margin will be evaluated to ensure that there has been no loss of containment intended function.

Evaluations performed on containment associated with potentially degraded rebar (i.e., localized surface degradation) have shown that loss of a number of reinforcing bars would have an insignificant effect on containment stress margins and would not impact containment intended function. Degradation of the rebar will be readily discernable as obvious changes in bar dimensions well before such degradation could progress to the point of challenging the available design margins.

(b) The technical adequacy of the 5-year IWL frequency of inspection of the degraded areas of the IPEC containments has-been demonstrated by past inspection results. No detectable changes have occurred over the 5-year period between past inspections. The rate of degradation of the exposed rebar of the containments has been imperceptible.

Documented inspection history for the first period IWL inspection began in 1999. Photographs taken of exposed rebar in the most recent inspection in 2009 were compared to photographs taken during the first IWL interval inspection in 2000 and a subsequent inspection in 2005. As can be seen from the photos in Figures 5 through 7 corrosion of the exposed rebar is almost nonexistent with no noticeable change in appearance over the years. Spalling is confined to a small area around the rebar with no noticeable cracking being present, which would indicate that the degradation is localized or has not progressed along the length of the rebar creating the potential for more spalling. Therefore, based upon past and recent inspection, increased corrosion rates have not been identified and additional degradation, which could prevent the containment from performing its intended function, would be readily detected by the established IWL inspections.

The staff reviewed the applicant's May 1, 2009 response to follow-up RAI 3: Open Item 3.0.3.3.2-1 (Audit Question 361), and the applicant's previous responses concerning the spalling of the IP2 containment exterior surface. The staff noted the following:

- Spalling on the external surface of the IP2 concrete containment was first documented during the 2000 ASME Subsection IWL inservice inspection. The spalls occurred in the vertical reinforcing steel at locations where the reinforcing bars are spliced using Cadweld sleeves. The diameter of the Cadweld sleeves is about two times that of the reinforcing bars.

- The 2005 IWL inspection of the IP2 containment found little or no change in the conditions observed previously during 2000.

- The most recent inspection of the IP2 containment, during 2009, using enhanced remote visual optical aids indicated little, if any, additional degradation of the concrete and reinforcing steel since 2000. This is based on a comparison of photographs taken during 2000 and 2009 of the same areas.

- According to the applicant's analysis and evaluation, the design margin provided at IP2 is at least 37 percent more than what is required by the design code. Currently, the surface corrosion on the exposed Cadweld sleeves is the only observed degradation. This degradation is insignificant when compared to the available margin.

Based on the regular IWL inspections conducted every 5 years, and the use of enhanced remote visual aids to monitor and trend the currently degraded locations, there is reasonable assurance that any additional degradation of the IP2 concrete containment would be identified prior to a loss of intended function. If additional degradation of the IP2 containment is detected during the period of extended operation, the degradation will be evaluated and resolved in accordance with the Containment Inservice Inspection Program. Therefore, the staff concludes that the effects of aging on the IP containment concrete will be adequately managed in accordance with 10 CFR 54.21(a)(3). On this basis, Open Item 3.0.3.3.2-1 is closed.

UFSAR Supplement. In LRA Sections A.2.1.7 and A.3.1.7, the applicant provided the UFSAR supplement for the Containment Inservice Inspection Program. The staff reviewed these sections and finds the UFSAR supplement information provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

By letter August 14, 2008, the applicant added Commitment 37 to enhance the Containment Inservice Inspection Program to include inspections of the containment using enhanced characterization of degradation during the period of extended operation.

Conclusion. On the basis of its technical review of the applicant's Containment Inservice Inspection Program, and review of the applicant's responses to the staff's RAIs, the staff concludes that the applicant has demonstrated that effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.3 Heat Exchanger Monitoring Program

Summary of Technical Information in the Application. LRA Section B.1.17 describes the existing Heat Exchanger Monitoring Program as a plant-specific program.

The Heat Exchanger Monitoring Program inspects by visual or other NDE techniques heat exchangers for loss of material. Inspection of heat exchanger (HX) tubes is at frequencies based on plant- and application-specific history, heat exchanger operating conditions, and heat exchanger availability. Inspection frequencies may be changed based on engineering evaluation of inspection results.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in LRA Section B.1.17 on the applicant's demonstration of the Heat Exchanger Monitoring Program to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

The staff reviewed the Heat Exchanger Monitoring Program against the AMP elements found in the GALL Report, in SRP-LR Section A.1.2.3, and in SRP-LR Table A.1-1, focusing on how the program manages aging effects through the effective incorporation of 10 elements ((1) "scope of the program," (2) "preventive actions," (3) "parameters monitored or inspected," (4) "detection of aging effects," (5) "monitoring and trending," (6) "acceptance criteria," (7) "corrective actions," (8) "confirmation process," (9) "administrative controls," and (10) "operating experience").

The applicant indicated that program elements (7) "corrective actions," (8) "confirmation process," and (9) "administrative controls" are parts of the site-controlled QA program. The staff's evaluation of the QA program is in SER Section 3.0.4. Evaluation of the remaining seven elements follows:

(1) Scope of the Program - LRA Section B.1.17 states that the Heat Exchanger Monitoring Program manages loss of material on selected heat exchangers required for efficient and reliable power generation. Steam generators are not included in this program.

    The applicant indicated it will enhance the applicable procedures of the existing program, to include the following heat exchangers in the scope of the program:

    - safety injection pump lube oil heat exchangers
    - RHR heat exchangers
    - RHR pump seal coolers
    - non-regenerative heat exchangers
    - charging pump seal water heat exchangers
    - charging pump fluid drive coolers
    - instrument air heat exchangers (IP3 only)
    - spent fuel pit heat exchangers
    - secondary system steam generator sample coolers
    - waste gas compressor heat exchangers

- SBO/Appendix R diesel cooling water heat exchangers (IP2 only)

By letter dated December 18, 2007, in response to Audit Item 52, Entergy described the heat exchangers currently included in the existing program, which is called the Eddy Current Program. Appendices 1 and 2 of the program document provide the detailed list of the heat exchangers for units 2 and 3, respectively.

Additionally, Entergy provided a description identifying the correlation between the HX tubes listed in AMR Tables 3.3.2-1 through 3.3.2-16 and those listed in the scope section of the AMP. In response to this question, Entergy also indicated that it needs to revise the LRA to address two items as follows: (1) the line item in AMR Table 3.3.2-2 IP3 Service Water refers to the instrument air copper alloy heat exchangers IP3 SWN CLC 31/32 HTX. Including this heat exchanger as part of the enhancement is not appropriate since these are already in the existing eddy current inspection program; (2) the LRA needs to be revised to include the charging pump crankcase oil cooler (IP3-CHRG PP31/32/33 CRANK HTX).

The staff reviewed the response and determined that, with the two corrections noted above, there is a match between the applicable heat exchangers listed in AMR Tables 3.3.2-1 through 3.3.2-16 and those listed in the scope section of the AMP. The staff confirmed that Entergy formally amended the LRA, by letter dated December 18, 2007, to incorporate these corrections.

By letter dated December 18, 2007, in response to Audit Item 56, Entergy indicated that this AMP manages the aging effect of loss of material due to wear for the HX tubes included in the scope. Some of the heat exchangers are classified as ISI Class 1, 2, & 3 and do fall under the jurisdiction of ASME, Code Section XI inservice inspection and repair/replacement requirements associated with the pressure boundary. The heat exchanger monitoring program does not implement any of the repair/replacement or inspection activities of these codes.

During the review of the Eddy Current Program, the staff noted that Section 2.2 of the program indicates that the IP Eddy Current Program is not part of the ASME Section XI ISI/inservice testing programs. Section 2.2 also states that the ASME Code does not mandate BOP heat exchanger eddy current inspections. Therefore, inspections are not performed for specific compliance with any ASME Code, Section V or XI requirements. ASME Code, Section V, Article 8, Appendix I is utilized for the development of OD flaw calibration standards.

Based on the description of the heat exchangers included in the existing Eddy Current Program and the additional heat exchangers listed as enhancements, the staff determines that the scope of this AMP includes all components which credit this AMP in the AMR.

The staff confirmed that the "scope of the program" program element satisfies the guidance in SRP-LR Section A.1.2.3.1. The staff finds this program element acceptable.

(2) Preventive Actions - LRA Section B.1.17 states that this is an inspection program and no actions are taken as part of this program to prevent degradation.

The staff confirmed that the “preventive actions” program element satisfies the guidance in SRP-LR Section A.1.2.3.2. The staff finds this program element acceptable.

(3) Parameters Monitored or Inspected - LRA Section B.1.17 states that visual or other non-destructive examinations of shell-and-tube HX tubes are performed to determine tube wall thickness, thereby managing the aging effect of loss of material. The applicant indicated it will enhance appropriate procedures, to perform visual inspection on heat exchangers where non-destructive examination, such as eddy current testing, is not possible due to heat exchanger design limitations.

By letter dated December 18, 2007, in response to Audit Item 53, Entergy explained that the wear that is identified by this aging effect occurs on the outside of the tubes due to contact between the tubes and the tube support plates. This wear may be caused by vibrations of the tubes because of high flows or excessive clearance between the tubes and the tube support plates. Wear due to abrasive fluid at high velocity is not expected due to the controlled water chemistry of the fluids on the shell and tube sides. The staff determined that the eddy current testing or visual inspection methods described in this AMP could be used to monitor the wall thickness of the HX tubes to detect the presence of and extent of the loss of material.

By letter dated December 18, 2007, in response to Audit Item 54, Entergy indicated that all of the heat exchangers in the existing program are large enough so that eddy current testing of the tubes can be performed. Visual inspections are not performed routinely. Some of the new heat exchangers added in the enhancement are small, and thus may preclude the possibility to perform eddy current testing. In these cases visual inspection would be needed. The staff concurs that, for those heat exchangers that are not large enough to perform eddy current testing, visual inspection of the tubes for wall loss is an acceptable method to detect loss of material.

By letter dated December 18, 2007, in response to Audit Item 55, Entergy indicated that if eddy current testing of the tubes is not practical due to the size of the heat exchanger, configuration, and tube size, then a remote visual inspection of the tubes may be required. The remote visual examination may be performed using a fiberscope placed inside the tubes or on the tube exterior from the shell side. The specific acceptance criteria of the program will be revised to require that no unacceptable signs of degradation are present. This was identified as Commitment 10. The eddy current tests have an acceptance criterion, which is determined by engineering evaluation on a heat exchanger-specific basis. The staff concludes that the use of remote visual examination methods by a fiberscope placed inside or on the outside surface of the tubes could detect loss of material of the HX tubes, and thus is acceptable. The specific acceptance criterion for the visual inspection consisting of no unacceptable signs of degradation is considered acceptable because it would identify any loss of material of the tube walls. The inclusion of the acceptance criterion for visual inspection of the tubes is a new enhancement to the existing program. Entergy has formally submitted Commitment 10, as part of an LRA amendment.

The staff confirmed that the “parameters monitored or inspected” program element satisfies the guidance in SRP-LR Section A.1.2.3.3. The staff finds this program element acceptable.

(4) Detection of Aging Effects - LRA Section B.1.17 states that loss of material is the aging effect managed by this program. Representative tubes within the sample population of heat exchangers are inspected at a frequency determined by plant-specific and industry operating experience to ensure that effects of aging are identified prior to loss of intended function. An appropriate sample population of heat exchangers is determined based on operating experience prior to inspections. The sample population of heat exchangers is determined based on the materials of construction of the HX tubes and the associated environments as well as the type of heat exchanger (for example, shell and tube type). Inspection can reveal loss of material that could result in degradation of the HXs. The applicant indicated it will enhance appropriate procedures, to include consideration of material-environment combination when determining sample population of heat exchangers.

Components whose inspection results continually indicate no new indications from previous inspections are candidates for inspection frequency lengthening. Conversely, the inspection frequencies for components with indications of an increasing trend when compared to previous inspections are evaluated for an increase in inspection frequency.

The staff reviewed Section 2.4 of the applicant's Eddy Current Program and noted that the eddy current inspection frequencies are described therein. Appendices 1 and 2 list the specific inspection frequencies for each heat exchanger. Section 2.4 states that the frequencies are based on plant-specific and application-specific knowledge, as well as past history, current HX operating conditions, and unit availability/outage schedules. The existing program also indicates that the established intervals are selected in order to uncover potential tubing problems before failure occurs.

The staff also reviewed Section 2.5 of the Eddy Current Program and noted that the program defines the sampling plan. In general, all of the tubes will be inspected for small HXs. For other HXs, the sampling size depends on the material of the HX tubes and the specific operating experience of the HX. Based on the enhancement described above, the material-environment combination will also be considered when determining sample population of HXs. Appendices 1 and 2 of the Eddy Current Program list the approximate sampling size in percentages of the total number of tubes for each HX. When less than a 100% inspection is performed, the program indicates that efforts be made to ensure that the tubes randomly selected during each inspection are different from the previously inspected tubes in order to approach a 100% inspection of the tubes over the many inspections performed.

As noted in Section 2.13 of the Eddy Current Program, the eddy current vendor provides reports which contain the results of the inspections. A record of all inspections for each component in the program is maintained on an on-going basis.

The staff finds that the eddy current inspection frequencies, sampling plan, and data collection, as summarized above, is appropriate for detecting loss of material before there is a loss of the component intended function, and thus this program element is acceptable.

The staff confirmed that the "detection of aging effects" program element satisfies the guidance in SRP-LR Section A.1.2.3.4. The staff finds this program element acceptable.

(5) Monitoring and Trending - LRA Section B.1.17 states that results are evaluated against established acceptance criteria and an assessment made regarding the applicable degradation mechanism, degradation rate and allowable degradation level. This information is used to develop future inspection scope, to modify inspection frequency, or replacement of the component if appropriate. Wall thickness is trended and projected to the next inspection. Corrective actions are taken if projections indicate that the acceptance criteria may not be met at the next inspection.

The staff confirms that the existing program contains monitoring and trending criteria for the HXs. The criteria require that an estimate of the HX remaining service life be made based on the inspection results. The inspection results are compared with previous successive data in order to estimate the growth rate of the tube damage. If the growth rate for a particular tube is estimated to result in the tube exceeding the established plugging criteria prior to the next scheduled inspection, the tube will be plugged as a precautionary measure. The description included in the existing program ensures that monitoring and trending is performed for the collected data and that the data are properly evaluated to determine whether corrective actions are needed before a loss of the HX intended function would occur.

The staff confirmed that the "monitoring and trending" program element satisfies the guidance in SRP-LR Section A.1.2.3.5. The staff finds this program element acceptable.

(6) Acceptance Criteria - LRA Section B.1.17 states that the minimum acceptable tube wall thickness for each HX inspected is based upon a component-specific engineering evaluation. Wall thickness is acceptable if greater than the minimum wall thickness for the component.

The applicant indicated it will enhance appropriate procedures, establishing the minimum tube wall thickness for the new HXs identified in the scope of the program; and revise appropriate procedures, establishing acceptance criteria for HXs that are visually inspected, to include no unacceptable signs of degradation.

The staff reviewed the acceptance criteria presented in the existing plant program, which define the maximum acceptable tube wall loss for HX tubes, in order to determine whether tube plugging is required. The existing program notes that ASME Section XI does not provide code-allowable minimum wall thickness requirements for HX tubes. Therefore, the existing program utilizes the EPRI guidance for determining the tube plugging criteria. Appendices 3 (for IP2) and 4 (for IP3) of the Eddy Current Program present a summary table for the allowable wall loss percentage for the HXs, based on the EPRI guidance documents. In addition to the tube wall loss criteria, the existing program also provides HX replacement criteria. The program states that a HX and/or tube bundle will be identified for replacement if tube plugging has reached 10 percent or more of the total number of tubes, unless a specific calculation has been previously prepared to the contrary. Inspection results of HX tubes will be compared with previous successive data in order to estimate a growth rate of the tube damage. The growth rate for a particular tube is determined to establish the plugging criterion prior to the next scheduled inspection to determine whether the tube will be plugged as a precautionary measure. A formula is provided in the existing program, which is used as a trending tool to estimate the tube remaining life in terms of the number of refueling cycles.

The existing program will be enhanced to include the minimum wall thickness for the new HXs added to the scope of the program, and to specify that if visual examination is performed, the acceptance criterion is “no unacceptable signs of degradation.” The acceptance criteria for the eddy current tests based on minimum wall thicknesses are acceptable. However, the staff determined that the acceptance criteria for visual examination are not clear and appear to be subjective; Entergy needs to clarify, preferably in quantitative terms, what acceptance criteria are used for the visual examination of the HX tubes. In RAI 3.0.3.3.3–1, the staff requested that Entergy define the visual inspection acceptance criteria in greater detail. Pending receipt and review of the applicant’s response, this was identified as Open Item 3.0.3.3.3–1.

By letter dated December 30, 2008, the staff requested that Entergy clarify, in quantitative terms, which acceptance criteria are used for the visual examination of the HX tubes.

By letter dated January 27, 2009, the applicant stated that the visual examinations of the HX tubes will be performed by a qualified engineer and will focus on the detection of loss of material that might be induced by erosion, wear, corrosion, pitting, fouling or scaling. The applicant also stated that the term “no acceptable signs of degradation” means no detection of these mechanisms such that the intended function of the HXs would be impaired. The applicant also clarified that if evidence of any of these mechanisms were to be noted by the qualified HX engineer, the engineer would base his evaluation of the degraded condition on design requirements and thickness of the HX tubes when taking into account the surface conditions caused by corrosion, erosion, pitting or wear, and or any scale or other foreign materials noted on the tubes.

The staff noted that ASME Code, Section XI cites VT-3 and VT-1 visual examination methods as acceptable visual examination methods for detecting surface discontinuities or imperfections in plant components, including those that might be indication of wear, erosion, corrosion (including pitting corrosion). The staff finds this to be acceptable because the applicant will be performing visual examinations of these HX tubes using methods that are capable of detecting surface discontinues or imperfections in the HX tubes and because the applicant will base acceptance of any relevant condition on the design requirements and thickness of the tubes. The staff concludes that RAI 3.0.3.3.3-1 is resolved and Open Item 3.0.3.3.3-1 is closed.

The staff confirmed that the “acceptance criteria” program element satisfies guidance in SRP-LR Section A.1.2.3.6. The staff finds this program element acceptable.

(10) Operating Experience - LRA Section B.1.17 states that results of eddy current testing of the tubes for several different IP2 HXs during 2000 through 2006 have indicated which tubes should be plugged, thus preventing the loss of the pressure boundary intended function. Detection of degradation, followed by corrective action prior to loss of intended function, proves that the program effectively manages aging effects for passive components.

A review of the IP2 HX inspection plan in September 2003 compared the scope of the IP2 inspections planned for refueling outage 2R16 (2004) against the typical scope of inspections planned for an IP3 refueling outage, and implemented recommended changes in the IP2 inspection scope. Use of shared best practices in the development of inspection plans assures continued program effectiveness in managing aging effects for passive components.

Results of eddy current testing of the tubes for several different IP3 HXs from 1997 through 2004 have indicated which tubes should be plugged, thus preventing the loss of the pressure boundary intended function. Detection of degradation and corrective action prior to loss of intended function prove that the program effectively manages aging effects for passive components.

An ongoing plan from a review of inspection intervals for IP3 components in April 2003 includes programmatic and technical activities for a wide range of HXs at IP3 to track improvements and corrective actions for the program. Detection of program weaknesses and subsequent corrective actions assure that the program will continue to manage loss of component material effectively.

The staff reviewed the program basis document discussion of operating experience for more information on applicable operating experience. The program basis document discussed the results of past eddy current testing of the tubes for several different IP2 and IP3 HXs, which resulted in the plugging of certain tubes.

The staff also reviewed a results report that was referenced in a program basis document. This document contains an IP3 Eddy Current Program Heat Exchanger Listing, which presents results from past operating experience of the tubes for different IP3 HXs during the period 1997 through 2004. The review of this table confirmed that the program is able to identify aging effects of loss of tube thickness before the loss of the pressure boundary intended function, and that corrective action was taken by plugging the appropriate tubes. This reference also has examples where the eddy current test frequency was increased (e.g., changed from once per eight years to once per two years in July 2000 for a particular HX), which demonstrates that the frequency of inspection is revised based on the operating experience.

The staff confirmed that the “operating experience” program element satisfies the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.16 and A.3.1.16, the applicant provided the UFSAR supplement for the Heat Exchanger Monitoring Program. The staff reviewed these sections and finds the UFSAR supplement information an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant’s Heat Exchanger Monitoring Program, the staff concludes that the applicant has demonstrated that effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.4 Inservice Inspection Program

Summary of Technical Information in the Application. LRA Section B.1.18, as amended by letter dated June 11, 2008, describes the existing Inservice Inspection Program as a plant-specific program.

LRA Section B.1.18 states that the Inservice Inspection Program encompasses ASME Section XI, Subsections IWA, IWB, IWC, IWD, and IWF requirements and 10 CFR 50.55a imposes ISI requirements of ASME Code, Section XI, for Classes 1, 2, and 3 pressure-retaining components, their attachments, and supports in light-water cooled power plants. Inspection, repair, and replacement of these components are addressed in Subsections IWA, IWB, IWC, IWD, and IWF. The program includes periodic visual, surface, and volumetric examination and leakage tests of Classes 1, 2, and 3 pressure-retaining components, their attachments, and supports.

ISI of supports for ASME piping and components is addressed in ASME Code, Section XI, Subsection IWF, which constitutes a mandated program for aging management of ASME Classes 1, 2, 3, and MC supports for license renewal. The program uses NDE techniques to detect and characterize flaws. Three types of examinations used are volumetric, surface, and visual. Volumetric examinations use radiographic, ultrasonic, or eddy current methods to locate surface and subsurface flaws. Surface examinations use magnetic particle or dye penetrant testing to locate surface flaws.

Three levels of visual examinations are specified. VT-1 visual examination, which assesses the surface condition of the part examined for cracks and symptoms of wear, corrosion, erosion, or physical damage, can be by either direct or remote visual observation using various optical/video devices. The VT-2 examination specifically locates evidence of leakage from pressure-retaining components (period pressure tests). While the system is under pressure for a leakage test, visual examinations detect direct or indirect indication of leakage. The VT-3 examination determines the general mechanical and structural condition of components and supports and detects discontinuities and imperfections. The Inservice Inspection Program is based on the ASME Section XI Inspection Program B (IWA-2432), which has 10-year inspection intervals. Every ten years the program is updated to the latest ASME Code, Section XI edition and addenda in 10 CFR 50.55a.

IP2 entered the fourth ISI interval on March 1, 2007. The ASME Code edition and addenda for the fourth interval for IP2 is the 2001 Edition with 2003 addenda. IP3 is currently in the third ISI interval. The ASME Code edition and addenda for IP3 is the 1989 Edition with no addenda. The program consists of periodic volumetric, surface, and visual examination of components and their supports for assessment, signs of degradation, flaw evaluation, and corrective actions. Augmented ISIs are also included as required by 10 CFR 50.55a, the staff, responses to requests for additional information, or as necessary under the program.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in LRA Section B.1.18 on the applicant’s demonstration of the Inservice Inspection Program to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

The staff noted that the applicant has categorized its Inservice Inspection Program as a "plant-specific" program.

The staff reviewed the Inservice Inspection Program against the staff's recommended program element criteria that are provided in SRP-LR Section A.1.2.3, and in SRP-LR Table A.1-1. The staff focused its review on assessing how the plant-specific program elements for the Inservice Inspection Program would ensure adequate aging management when compared to the recommended program element criteria that are given in SRP-LR Section A.1.2.3. Specifically, the staff reviewed the following eight program elements of the applicant's program: (1)"scope of the program," (2) "preventive actions," (3) "parameters monitored or inspected," (4) "detection of aging effects," (5) "monitoring and trending," (6) "acceptance criteria," (7) "corrective actions," and (10) "operating experience."

The applicant indicated that program elements (7) "corrective actions," (8) "confirmation process," (9) "administrative controls," are part of the site-controlled QA program. The staff's evaluation of the applicant's Quality Assurance Program is documented in SER Section 3.0.4.

The staff's evaluation of the remaining program elements are given in the paragraphs that follow:

(1) Scope of the Program - LRA Section B.1.18 states that "[t]he ISI Program provides the requirements for ISI, repair, and replacement. The components within the scope of the program are specified in Subsections IWB-1100, IWC-1100, IWD-1100, and IWF-1100 for Classes 1, 2, and 3 components and supports, Quality Groups A, B, and C respectively, and include all pressure-retaining components and their integral attachments. The components described in Subsections IWB-1220, IWC-1220, and IWD-1220 are exempt from the examination requirements of Subsections IWB-2500, IWC-2500, and IWD-2500.

The ISI Program manages cracking for carbon steel, carbon steel with stainless steel cladding, and stainless steel components, including bolting. The ISI Program implements applicable requirements of ASME Code, Section XI, Subsections IWA, IWB, IWC, IWD, IWF and other requirements specified in 10 CFR 50.55a with approved NRC alternatives. The ISI Program also manages reduction of fracture toughness for valve bodies and pump casing made of cast austenitic stainless steel. Both IP2 and IP3 use ASME Code Case N-481 as approved in Regulatory Guide 1.147 for managing the effects of loss of fracture toughness due to thermal aging embrittlement of CASS pump casing pressure retaining welds. ASME Code Case N-481 has been incorporated in later editions of the code and IP2 will not reference Code Case N-481 in the 4th interval."

SRP-LR Section A.1.2.3.1 states, "[t]he specific program necessary for license renewal should be identified. The scope of the program should include the specific structures and components of which the program manages the aging."

The staff noted that the requirements for inservice inspection program are mandated by the provisions in 10 CFR 50.55a. The staff verified that the rule requires U.S. licensees to establish inservice inspection (ISI) programs for their ASME Code Class components, structures, and component supports and requires U.S. licensees to apply the ISI requirements that are provided in the provisions of the ASME Boiler and Pressure Vessel Code, Section XI, Division 1 (henceforth ASME Code, Section XI), Subsections

IWA, IWB, IWC, and IWD for the AMSE Code Class 1, 2, and 3 components, in Subsection IWF for ASME Code Class component supports, and in Subsection IWA for generic ISI requirements. The current edition of the rule permits use of ASME Code, Section XI editions through 2001 Edition of the ASME Code, Section XI, inclusive of the 2003 Addenda.

In LRA Amendment 5, dated June 11, 2008, the applicant amended AMP B.1.18 to clarify that the applicable edition credited for aging management of ASME Code Class components at IP2 within the scope of the AMP is the 2001 Edition of the ASME Code, Section XI, inclusive of the 2003 Addenda. Although the Inservice Inspection Program is a plant-specific AMP for the LRA and does not need to conform to the staff's program element guidance in GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," the staff noted that GALL AMP XI.M1 identifies that the 2001 Edition of the ASME Code, Section XI, inclusive of the 2003 Addenda, is an acceptable ASME Code, Section XI edition for Inservice Inspection Programs that are credited for aging management of ASME Code Class components. Thus, the staff finds this update of the Inservice Inspection Program to be acceptable because it is in conformance with the "scope of program" program element in GALL AMP XI.M1.

In LRA Amendment 5, dated June 11, 2008, the applicant amended AMP B.1.18 to clarify that the applicable edition credited for aging management of ASME Code Class components at IP3 within the scope of the AMP is the 1989 Edition of the ASME Code, Section XI, with no addenda. Although the Inservice Inspection Program is a plant-specific AMP for the LRA and does not need to conform to the staff's program element guidance in GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," the staff noted that the staff's 1995 SOC on 10 CFR Part 54 identifies that ASME Code, Section XI editions up through the 2001 Edition of the ASME Code, Section XI, inclusive of the 2003 Addenda, are acceptable ASME Code, Section XI editions for Inservice Inspection Programs that are credited for aging management of ASME Code Class components. Thus, the staff finds the ASME Code, Section XI edition (i.e., the 1998 edition of the code) credited for IP3 is acceptable for aging management because it is in conformance with the staff's SOC position on 10 CFR Part 54 regarding the ASME Code, Section XI editions that are acceptable for aging management.

The staff verified that components within the scope of the program include the ASME Code Class 1, 2, and 3 components that are specified in Subsections IWB-1100, IWC-1100, IWD-1100, and the ASME Code Class 1, 2, and 3 component supports that are specified in AMSE Code Section XI Subsection IWF-1100. The staff verified that the components include all pressure-retaining components and their integral attachments. Based on this review the staff finds that the applicant's identification of components that are within the scope of the applicant's Inservice Inspection Program is acceptable because is in compliance with the applicable components that are mandated for inspection in the ASME Code, Section XI, Subsections IWB, IWC, IWD, and IWF, as endorsed for use through reference in 10 CFR 50.55a.

Entergy also stated that the ISI programs manage loss of material for piping and component supports, anchorages, and base plates by visual examination of components using NDE techniques, frequencies, and sample sizes specified in Subsection IWF examination categories. Twenty-five percent of Class 1 piping supports, 15 percent of Class 2 piping supports, 10 percent of Class 3 piping supports, and 100 percent of other supports are subject to VT-3 visual examination, as required by the Code. Entergy stated that the examination categories are in accordance with Table IWF-2500-1 and that for piping supports, the total percentage sample is comprised of supports from each system where the individual sample sizes are proportional to the total number of nonexempt supports of each type and function within each system. Thus, the staff concludes that the scope of the Entergy's ISI program for the component supports is acceptable because it includes the items identified in GALL AMP XI.S3, and because this provides an acceptable basis for meeting SRP-LR Section A.1.2.3.1 with respect to the scoping of components supports for the program.

Based on this review, the staff confirmed that the "scope of the program" program element satisfies the guidance in SRP-LR Section A.1.2.3.1 because: (1) the scope of the program includes the applicable ASME Code 1, 2, and 3 components that are mandated for inservice inspection in the 1989 Edition of the ASME Code, Section XI, Subsection IWB, IWC, IWD and IWF, and because this in compliance with the requirements of 10 CFR 50.55a and in conformance with the staff's SOC on 10 CFR Part 54, and (2) consistent with the recommendation in SRP-LR Section A.1.2.3.1, the applicant identified the components that are with the scope of the AMP. The staff finds this program element acceptable.

(2) Preventive Actions - LRA Section B.1.18 states that the ISI Program is a condition monitoring program that does not include preventive actions.

For condition monitoring programs, SRP-LR Section A.1.2.3.2 states, "For condition or performance monitoring programs, they do not rely on preventive actions and thus, this information need not be provided."

The staff observed that the applicant's Inservice Inspection Program is characterized as a "condition monitoring" program that uses a combination of non-destructive and visual inspection methods to monitor for the effects of aging that are applicable to ASME Code Class 1, 2, and 3 components and their components supports. Based on its review, the staff concludes that the recommended guidance in SRP-LR Section A.1.2.3.2 is not applicable to the applicant's Inservice Inspection Program. Therefore, the applicant's "preventive actions" program element discussion for the Inservice Inspection Program is acceptable.

(3) Parameters Monitored or Inspected - LRA Section B.1.18 states that "the program uses nondestructive examination (NDE) techniques to detect and characterize flaws. Volumetric examinations such as radiographic, ultrasonic or eddy current examinations are used to locate surface and subsurface flaws. Surface examinations, such as magnetic particle or dye penetrant testing, are used to locate surface flaws. Visual examinations detect cracks and symptoms of wear, corrosion, physical damage, evidence of leakage, and general mechanical and structural condition."

For condition monitoring programs, SRP-LR Section A.1.2.3.3 states, "[t]he parameters to be monitored or inspected should be identified and linked to the degradation of the particular structure and component intended function(s)," and "[f]or a condition monitoring program, the parameter monitored or inspected should detect the presence and extent of aging effects. Some examples are measurements of wall thickness and detection and sizing of cracks."

The staff noted that Subsection IWA-2200 defines the ASME inspection methods that may be applied to ASME Code Class components and the parameters that these inspection methods are credited for. The staff also noted that IWA-2000 identifies that the various ASME inspection methods as a whole detect for aging effect parameters such as discontinuities or flaws (including cracking, pitting surface wastage, etc.), wear, corrosion, erosion, loss of integrity at bolted connections, and general mechanical and structural condition of the components. The staff also noted that the aging parameters discussed in IWA-2000 relate to the aging effects of loss of material, cracking, loss of preload, and reduction of fracture toughness in ASME Code Class components, The staff also noted that the aging effects identified in the applicant's "parameters monitored or inspected" program element were the same parameters as those identified and credited for in the ASME Code, Section XI, Subsection IWA-2200 paragraphs. Based on this review, the staff confirmed that the "parameters monitored or inspected" program element satisfies the guidance in SRP-LR Section A.1.2.3.3 because: (1) the parameters identified as being within the scope of the applicant's program are in compliance with those identified in ASME Code, Section XI, Subsection IWA-2200, and (2) the aging parameters within the scope of the program relate back to either to the aging effects of loss of material, cracking, loss of preload, or reduction of fracture toughness in ASME Code Class components. Based on this review, the staff finds this program element acceptable.

(4) Detection of Aging Effects - LRA Section B.1.18 states that the ISI Program manages cracking on subcomponents of the reactor vessel, as applicable, for carbon steel, nickel alloy, carbon steel with stainless steel cladding, and stainless steel components, including bolting, using NDE techniques specified in ASME Section XI, Subsection IWB examination category.

The ISI Program manages loss of material due to wear on reactor vessel internal subcomponents, as applicable, for nickel alloy and stainless steel clevis inserts, radial keys, core alignment pins, and head/vessel alignment pins using NDE techniques specified in ASME Section XI, Subsections IWB examination categories.

The ISI Program manages cracking on reactor coolant system components, as applicable, for carbon steel, carbon steel with stainless steel cladding, stainless steel and cast austenitic stainless steel components, including bolting and support skirts, using NDE techniques specified in ASME Section XI, Subsections IWB examination categories. The Inservice Inspection Program also manages reduction of fracture toughness for valve bodies and pump casing made of cast austenitic stainless steel.

The ISI Program manages cracking on steam generator system components, as applicable, for carbon steel, carbon steel with stainless steel cladding, and stainless steel components, using NDE techniques specified in ASME Section XI, Subsections IWB examination categories.

The ISI Program manages loss of material for ASME Class MC and Classes 1, 2, and 3 piping and component supports and their anchorages and base plates by visual examination of components using NDE techniques specified in ASME Section XI, Subsection IWF examination categories.

No aging effects requiring management are identified for lubrite sliding supports. However, the ISI Program will confirm the absence of aging effects through the period of extended operation.

In the LRA, the applicant stated that the ISI Program will be revised to provide periodic inspections to confirm the absence of aging effects for lubrite sliding supports used in the steam generator and reactor coolant pump supports.

Both IP2 and IP3 have adopted risk-informed inservice inspection (RI-ISI) as an alternative to current ASME Section XI inspection requirements for Class 1, Category B-F and B-J welds pursuant to 10 CFR 50.55a(a)(3)(i). The RI-ISI was developed in accordance with the EPRI methodology contained in EPRI TR-112657, Revision B-A, “Revised Risk-Informed Inservice Inspection Evaluation Procedure.” The risk informed inspection locations are identified as Category R-A.

For IP2, Article IWF of ASME Section XI, 2001 Edition and 2003 Addenda, does not contain any specific exemption criteria for component supports. For IP3, components exempt from examination are in accordance with the criteria contained in Code Case N-491-2, Alternate Rules for Examination of Classes 1, 2, 3 and MC Component Supports of Light-Water Cooled Power Plants, Section XI, Division 1, IWF-1230.

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.4.

The staff noted that the specific Examination Categories and Inspection Items in Table IWB-2500-1 establish the inspection methods, inspection frequencies, and flaw acceptance standards that are to be used on ASME Code Class 1 components and that Examination Categories and Inspection Items in Tables IWF-2500-1 establish the inspection methods, inspection frequencies, and flaw acceptance standards that are to be used on ASME Code Class component supports. The staff noted that the applicant has credited the inspection requirements and inspection frequencies in applicable Table-IWB-2500-1 Examination Categories and Inspection Items for ASME Code Class 1 components and the inspection requirements, inspection frequencies, and sample sizes in applicable Table IWF-2500-1 Examination Categories and Inspection Items for ASME Code Class component supports. The staff finds this to be acceptable because it is in compliance with the requirements of 10 CFR 50.55a and the ASME Code, Section XI.

The staff noted that the LRA indicated that the applicant is crediting the inspection requirements and inspection frequencies in the applicable Table IWB-2500-1 Examination Categories and Inspection Items for the detection of aging effects in the steam generator (SG) secondary side shell, cone, and head components. The staff noted that, normally, the inspection requirements and inspection frequencies for the SG secondary side shell, cone, and head components would be performed in accordance with applicable requirements in the ASME Code, Section XI, Table IWC-2500-1 unless these components were designed to ASME Code Class 1 standards. The staff noted that the ASME Code, Section XI requirements in Subsection IWB are normally more stringent that those for ASME Code Class 2 and 3 requirements because the components are part of the reactor coolant pressure boundary. Thus, based on this review, the staff finds that using the inspection method and inspection frequency requirements for SG shell, cone, and head components is conservative because either the components were designed for ASME Code Class 1 standards and are inspecting in accordance with the applicable Examination Category and Inspection Items for these components in ASME Code, Section XI, Table IWB-2500-1 or that the components are ASME Code Class 2 or 3 components and use of the applicable Examination Category and Inspection Items for these components in ASME Code, Section XI, Table IWB-2500-1 is conservative relative to the requirements for inspection in Tables IWC-2500-1 or IWD-2500-1.

The staff noted that the AMRs in LRA Chapters 3.2, 3.3, and 3.4 did not credit the Inservice Inspection Program for aging management of the ESF components, auxiliary system (AUX) components, and steam and power conversion system (S&PC) components. Thus, the staff noted that the applicant was not crediting its implementation of the Examination Category requirements in ASME Code, Section XI, Table IWC-2500-1 for aging management of the ASME Code Class 2 components and the Examination Category requirements in ASME Code, Section XI, Table IWD-2500-1 for aging management of the ASME Code Class 3 components. The staff found this to be acceptable because the AMRs in Sections, V, VII, and VII of the GALL Report, Volume 2 do not credit GALL AMP XI.M1, “ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD,” for aging management of any of the aging effects that are attributed to ESF, AUX, and S&PC components.

The staff noted that the applicant indicated that it plans to enhance the Inservice Inspection Program to provide for periodic visual inspections of lubrite sliding supports used in the SG supports and reactor coolant pump (RCP) supports in order to confirm the absence of aging effects. The staff noted that the applicant could only treat this as an enhancement of the program if the AMP were categorized as an AMP that is consistent with the program elements in GALL AMP XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD,” and if the enhancement would make the “detection of aging effects” program element of the AMP consistent with the “detection of aging effects” program element criteria that are provided in GALL AMP XI.M1. Thus, the staff informed the applicant that the aging effects that are applicable to the lubrite SG and RCP supports would need to be identified during the staff’s review of the LRA and that the applicant would need to establish and justify its selection of the inspection methods, inspections frequencies, sample sizes, and acceptance criteria that are applicable to these lubrite components, and the corrective actions that would implemented if these acceptance criteria are exceeded. This was identified as Open Item 3.0.3.3.4-1.

The applicant responded to RAI 3.0.3.3.4-1 in a letter dated January 27, 2009. In this letter, the applicant identified the lubrite sliding supports in the SGs and RCPs as ASME code class supports that are within the scope of the requirement in the ASME Code, Section XI, Article IWF. In this letter, the applicant identified loss of material by wear and locking of the lubrite sliding supports by abnormal surface roughness as applicable aging effects for the lubrite sliding supports. The applicant clarified that there have not been any recordable indications of wear or abnormal surface roughness in the lubrite sliding supports detected to date and that as a result of this, the inspections performed on the sliding lubrite supports will be VT-3 visual examinations in order to confirm that these conditions do not exist in the supports. The applicant clarified that the inspection frequency and sample size of these VT-3 visual examinations will be done in accordance with the requirements of the ASME Code, Section XI, Article IWF, and that if any wear or abnormal surface roughness is detected, the applicant will evaluate the recordable conditions against the acceptance criteria in ASME Code, Section XI paragraph IWF-3410(a). The applicant stated that corrective actions for the component supports would be initiated in accordance with the requirements of the applicant's 10 CFR Part 50, Appendix B quality assurance program.

The staff noted that these lubrite sliding supports are supports for the RCPs, which are ASME Code Class 1 pumps in the reactor coolant pressure boundary, and for the SGs, which are classified as ASME Code class vessels/heat exchangers that have both an ASME Code Class 1 reactor coolant pressure boundary side and either an ASME Code Class 2 or Class 3 non-reactor coolant pressure boundary side. The staff also noted that the inspection methods, frequency and sample size for these supports is mandated by 10 CFR 50.55a and by Inspection Item F1.40, "Supports Other Than Piping Supports," in the ASME Code, Section XI, Table IWF-2500-1, Examination Category F-A. The staff noted that this inspection item pertains to non-piping supports in ASME Code Class 1, 2, and 3 piping systems and in MC structures, and calls for a VT-3 examination of 100% of these supports once every 10-Year ISI interval. Based on these verifications, the staff finds that the applicant has provided an acceptable basis for inspecting these lubrite sliding supports because: (1) the applicant has indicated that it will inspect the supports using the applicable ISI requirements for the supports, (2) these inspections will be done in accordance with the requirements of Inspection Item F1.40, "Supports Other Than Piping Supports," in the ASME Code, Section XI, Table IWF-2500-1, Examination Category F-A, and (3) this is consistent with the "detection of aging effects" and "monitoring and trending" program elements in GALL AMP XI.S3, "ASME Section XI, Subsection IWF." The staff concludes that RAI 3.0.3.3.4-1 is resolved and Open Item 3.0.3.3.4-1 is closed with respect to the inspection methods, frequencies, and sample sizes that are credited for these lubrite sliding supports.

The staff noted that Subparagraph IWF-3410(a) of the ASME Code, Section XI provides the appropriate acceptance criteria for relevant conditions in ASME Code Class 1, 2, or 3 components supports, including (but not limited to) those that induce deformations, structural degradations, misalignments, or improper clearances of the supports (such as might be induced if wear were occurring in the components), or abnormal surface roughness (such as might be induced if scaling or corrosion products were to form on the components). Based on this verification, the staff finds that the applicant has provided an acceptable basis for evaluating any relevant indications in the lubrite sliding supports because: (1) the applicant will use the mandated acceptance criteria in Subparagraph IWF-3410(a) of the ASME Code, Section XI as its basis for evaluating any relevant conditions that might occur in these ASME Code Class lubrite sliding supports and (2) this is consistent with the "acceptance criteria" program element in GALL AMP XI.S3. The staff concludes that RAI 3.0.3.3.4-1 is resolved and Open Item 3.0.3.3.4-1 is closed with respect to the acceptance criteria that are credited for these lubrite sliding supports.

The staff noted the GALL AMP XI.S3 identifies that the applicant's 10 CFR Part 50, Appendix B quality assurance program is an acceptable basis for establishing the corrective actions for ASME Code Class component supports because the Quality Assurance program would ensure that the corrective actions would be implemented in accordance with applicable requirements in the ASME Code, Section XI, Subparagraph IWF-3122. Based on this verification, the staff finds that the applicant has provided acceptable corrective actions for the lubrite sliding supports because: (1) the applicant has specified that the corrective actions for these supports will be implemented in accordance with the applicant's 10 CFR Part 50, Appendix B program, and (2) this is consistent with the "corrective actions" program element in GALL AMP XI.S3. The staff concludes that RAI 3.0.3.3.4-1 is resolved and Open Item 3.0.3.3.4-1 is closed with respect to the corrective actions that are credited for these lubrite sliding supports.

In Audit Item 60, the staff asked the applicant to justify its basis for using risk-informed inservice inspection (RI-ISI) for Examination Category B-J and B-F piping welds and for applying and using NRC-approved Code Case N-532 during the period of extended operation. In its response, dated December 18, 2007, Entergy amended the LRA to remove from the LRA sentences referencing these items. At the same time, Entergy stated that IP ISI programs would continue to be implemented in full compliance with the Code requirements during the period of license renewal. The staff verified the applicant updated its Code of Record for IP2 to the 2001 Edition of the ASME Code, Section XI through 2003 Addenda. For IP3, the Code of Record is the 1989 Edition of the ASME Code, Section XI with no Addenda. The staff finds this to be acceptable because the SOC on 10 CFR Part 54 clarifies that the 2001 Edition of the ASME Code through 2003 Addenda and the 1989 Edition of the ASME Code with no Addenda are acceptable editions of the ASME Code, Section XI to use for aging management.

Based on this review, the staff confirmed that the "detection of aging effects" program element satisfies the guidance in SRP-LR Section A.1.2.3.4 because the applicant is applying the inspection methods, inspection frequencies, and samples sizes in Table IWB-2500-1 for ASME Code Class 1 components and for SG secondary side shell, cone, and head components and in Table IWF-2500-1 for ASME Code Class components supports and because these methods meet the SRP-LR Section A.1.2.3.4 criteria for applicants to justify the inspection methods, inspection frequencies and sample sizes that they select for aging management. Based on this review, the staff finds this program element acceptable.

(5) Monitoring and Trending - LRA Section B.1.18 states that results are compared, as appropriate, to baseline data and other previous test results. Indications are evaluated in accordance with ASME Section XI. If the component is qualified as acceptable for continued service, the area containing the indication is reexamined during subsequent inspection periods. Examinations that reveal indications that exceed the acceptance standards are extended to include additional examinations in accordance with ASME Section XI.

Inservice Inspection results are recorded every operating cycle and provided to the NRC after each refueling outage via Owner's Activity Reports. These reports include scope of inspection and significant inspection results. They are prepared and submitted in accordance with NRC-accepted ASME Section XI Code Case N-532-1 as referenced in RG 1.147.

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.5.

The staff's bases for approving the applicant inspection frequencies and sample sizes used in the inspections of ASME Code Class components has been discussed and justified in the staff's evaluation of the "detection of aging effects" program element for this AMP.

The staff noted that the applicant indicated that indications are evaluated against stated standards in the ASME Code, Section XI, and if found acceptable for service, the areas containing the indications are re-inspected during the next scheduled outage. The staff noted that that Articles IWB-2000, IWC-2000, and IWD-2000 all include criteria for performing successive inspections on component indications that are found to be acceptable for continued service, and for expanding the sample size if the indications exceed the applicable flaw standard used for analysis in the Code. Based on this review, the staff finds the applicant's "monitoring and trending" program element description for performing successive inspections and sample expansion to be acceptable because it is in compliance with the requirements in ASME Code, Section XI.

In terms of record retention and reporting of data requirements, the staff noted that the applicant stated that records are prepared and provided to the NRC in accordance with applicable Owner's Activity Reports. The staff also noted that the ASME Code, Section XI, Article IWA-6000 provides the requirements for recording of data and reporting this data to the NRC, including requirements for defining owner activities and responsibilities, completing of NIS-1 data record forms, preparation of summary reports, submittal of summary to the NRC authorities, retaining records, reproducing records (including digitization requirements and microfiche requirements), retention of construction record requirements, maintenance of ISI records, retention of repair/replacement and supplement evaluation records. Based on this review, the staff finds that the applicant's basis for the preparation, recording, and submittal of plant ISI data and data summaries is acceptable because it is in compliance with the staff's record retention and reporting requirements in ASME Code, Section XI, Article IWA-6000.

Based on this review, the staff confirmed that the "monitoring and trending" program element satisfies the guidance in SRP-LR Section A.1.2.3.5 because: (1) the applicant has demonstrated that it will continue to comply with the requirements in Article IWA-6000 for record preparation, record retention and data and record reporting requirements and in Articles IWB-2000, IWC-2000, and IWD-2000 for performing successive inspections and for sample expansion, and (2) because the applicant has satisfied the "monitoring and trending" program element in SRP-LR Section A.1.2.3.5 for performing successive inspections of relevant flaw indications, sample expansion, and for record preparation, record retention, and data reporting. Based on this review, the staff finds this program element acceptable.

(6) Acceptance Criteria - LRA Section B.1.18 states that a pre-service, or baseline, inspection of program components was performed prior to startup to assure freedom from defects greater than code-allowable. This baseline data also provides a basis for evaluating subsequent inservice inspection results. Since plant startup, additional inspection criteria for Classes 2 and 3 components have been imposed by 10 CFR 50.55a for which baseline and inservice data has also been obtained. Results of inservice inspections are compared, as appropriate, to baseline data, other previous test results, and acceptance criteria of the ASME Section XI, for evaluation of any evidence of degradation.

The ISI Program acceptance standards for flaw indications, repair procedures, system pressure tests and replacements for ASME Classes 1, 2, and 3 components and piping are defined in ASME Section XI subsections IWA, IWB, and IWC paragraphs 3000, 4000, 5000 and 7000, respectively. Acceptance standards for examination evaluations, repair procedures, inservice test requirements, and replacements for ASME Class 1 component and piping supports are defined in ASME Section XI paragraphs IWF-3000, IWF-4000, IWF-5000 and IWF-7000, respectively."

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.6.

The staff noted that the applicant indicated that it is using the applicable "acceptance criteria" in the ASME Code, Section XI, Subsections IWB, IWC, and IWD as its bases for establishing the acceptance criteria for assessing relevant indications in ASME Code Class components and in Subsection IWF for ASME Code Class supports. The staff noted that the flaw acceptance standards in the ASME Code, Section XI are based on satisfying the design basis loading conditions that are applicable to ASME Code Class components. The staff finds this to be acceptable because: (1) it is in compliance with the "acceptance criteria" requirements in the ASME Code, Section XI for Code Class 1, 2, and 3 components and their components supports, (2) these flaw evaluation criteria are based on a standard of meeting design basis loading conditions, and (3) this is in conformance with the recommended criteria in SRP-LR Section A.1.2.3.6.

Based on this review, the staff confirmed that the "acceptance criteria" program element satisfies the guidance in SRP-LR Section A.1.2.3.6 because: (1) the applicant is using the applicable acceptance criteria in the ASME Code, Section XI for the IP2 and IP3 ASME Code Class 1, 2, and 3 components and their components supports, and (2) this satisfies the criterion in SRP-LR Section A.1.2.3.6 to provide for timely corrective action before loss of intended function under these CLB design loads. The staff finds this program element acceptable.

(7) Corrective Actions – LRA Section B.1.8 states that "[i]f a flaw is discovered during an ISI examination, an evaluation is conducted in accordance with articles IWA-3000 as appropriate. If flaws exceed acceptance standards, such flaws are removed or repaired, or the component is replaced prior to its return to service. For Class 1, 2, and 3, repair and replacement are in conformance with IWA-4000 and IWA-7000. Acceptance of flaws which exceed acceptance criteria may be accomplished through analytical evaluation without repair, removal or replacement of the flawed component if the evaluation meets the criteria specified in the applicable article of the code. Corrective actions for this program will be administered under the site QA program which meets requirements of 10 CFR Part 50, Appendix B."

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.7.

As discussed in the evaluation of the "scope of program" program element for the Inservice Inspection Program, the staff verified that the applicant's ASME Section XI Code of Record for IP2 for the 4th 10-year ISI interval is the 2001 Edition of ASME Code, Section XI through 2003 Addenda, and for IP3 for the 3rd 10-year ISI interval is the 1989 Edition of ASME Code, Section XI with no Addenda. The staff's corrective actions for

ASME Code Class 1, 2, and 3 components in these ASME Code, Section XI editions are defined and specified in General Article IWA-4000, and in the specific corrective action provisions in IWB-4000 for Class 1 components, IWC-4000 for ASME Code Class 2 components, and IWD-4000 for ASME Code Class 3 components. The staff verified that the specific corrective action in articles IWB-4000, IWC-4000, and IWD-4000, provides either specific corrective action criteria for a specific ASME Code Class component or refers back to general corrective action provisions for these components that are contained in Article IWA-4000. The staff also verified that these corrective actions are mandated for these components in accordance with inservice inspection requirements in 10 CFR 50.55a.

The staff noted that the "corrective actions" program element for AMP B.1.18, Inservice Inspection Program, credits only the corrective actions in the ASME Code, Section XI, Articles IWA-4000 and IWA-7000 as the corrective action criteria for the program. The ASME Code, Section XI editions of record for IP are the 2001 Edition of the ASME Code, Section XI inclusive of the 2003 Addenda for IP2, and the 1989 Edition of the ASME Code, Section XI, with no addenda for IP3. The staff noted that Entergy did not credit component-specific corrective action criteria in ASME Section XI, Article IWB-4000/7000 for Class 1 components, Article IWC-4000/7000 for Class 2 components, Article IWD-4000/7000 Class 3 components, or Article IWF-4000/7000 for ASME Code Class component supports as being within the scope of the "corrective action" program element for this AMP. By letter dated December 30, 2008, the staff asked the applicant to clarify whether the content of the "corrective actions" program element was intended to mean that Entergy will implement the corrective action provisions in the ASME Code, Section XI, Subsections IWA, IWB, IWC, IWD, and IWF that are applicable to the component Code Class in the applicable ASME Code, Section XI edition of record. This was identified as Open Item 3.0.3.3.4-2.

The applicant responded to the staff's RAI in a letter dated January 27, 2009. In this letter the applicant clarified that the content of the "corrective actions" program element discussion for this AMP is intended to mean that the corrective actions for this AMP will be implemented in accordance with the corrective actions provisions that are appropriate for ASME Code Class 1, 2, 3 components in the ASME Code, Section XI, Articles IWA, IWB, IWC, and IWD and for ASME Code Class component supports in the ASME Code, Section XI, Article IWF.

The staff noted that the applicant's response cited the appropriate ASME Code, Section XI corrective action articles for ASME Code Class 1, 2, and 3 components and for ASME Code Class supports. The staff also noted that the applicant's 10 CFR Part 50, Appendix B, quality assurance program includes appropriate quality assurance activities to ensure that inspections and corrective actions for ASME Code Class 1, 2, and 3 components and component supports will be done in accordance with appropriate requirements in the ASME Code, Section XI, ASME Code Cases referenced for use in 10 CFR 50.55a and the latest revision of NRC Regulatory Guide 1.147, or through applicable relief requests that are requested and approved by the staff through the alternative ISI requirements process in 10 CFR 50.55a(a)(3). The staff finds the "corrective actions" program element for this AMP, as amended in the response to RAI 3.0.3.3.4-2, to be acceptable because: (1) the applicant has indicated that the corrective actions for the ASME Code Class 1, 2, and 3 components and component supports will be done in accordance with appropriate ASME Code, Section XI requirements, (2) the applicant's

10 CFR Part 50, Appendix B quality assurance program provides an acceptable basis to ensure that corrective actions for ASME Code Class 1, 2, and 3 components and component supports will be done in accordance with appropriate AMSE Code Section XI requirements, NRC-approved ASME Code Cases, or alternative program requirements approved in accordance with 10 CFR 50.55a, and (3) this is consistent with the "corrective actions" program element criteria for ASME Code Class 1, 2, and 3 components in GALL AMP XI.M1 and for ASME Code Class component supports in GALL AMP XI.S3. The staff concludes that RAI 3.0.3.3.4-2 is resolved and Open Item 3.0.3.3.4-2 is closed with respect to the acceptability of the "corrective actions" program element for this AMP.

(10) Operating Experience - LRA Section B.1.18 states that:

> ISI examinations at IP2 and IP3 were conducted during 2004 and 2005. Results found to be outside of acceptable limits were either repaired, evaluated for acceptance as is, or replacement activities were initiated. Identification of degradation and performance of corrective action prior to loss of intended function are indications that the program is effective for managing aging effects.
>
> A self-assessment of the ISI program was completed in October 2004. Review of current scope for 2R16 (2004) and 3R13 (2005) verified that the proper inspection percentages had been planned for both outages. A follow-up assessment was held for IP2 in March 2006 to ensure that all inspection activities required to close out the third 10-year ISI interval were scheduled for 2R17 (2006). Confirmation of compliance to program requirements provides assurance that the program will remain effective for managing loss of material of components.
>
> QA surveillances in 2005 and 2006 revealed no issues or findings that could impact effectiveness of the program.

The staff reviewed the self-assessment and QA audit reports for the ISI program and confirmed that the QA audit documents indicated that the IP ISI program appropriately identified and took corrective measures on the inspection findings. The staff also noted that the QA audit documents indentified several deficiencies with the applicant's ISI Program and provided appropriate recommendations to correct them. The staff noted that the QA audit documents did not indicate any programmatic weaknesses that would impact the effectiveness of the ISI Program in accomplishing its intended objectives or functions.

In RAI RCS-2, the staff asked the applicant, in part, to clarify how it performed its condition report review for relevant operating experience related to implementation of this program. The applicant provided its response to RAI RCS-2 in a letter dated June 5, 2008. The staff's evaluation of the applicant's response is documented in SER Section 3.0.3.2.9.

The staff noted that the applicant's response to RAI RCS-2 indicated that the applicant had performed an extensive enough review to search for and locate reports or documentation that would provide evidence of age-related aging effects in the IP2 or IP3

ASME Code Class 1 components. Thus, based on the response to RAI RCS-2, as made relative to the Inservice Inspection Program, the staff concludes that the applicant has performed a sufficient review for relative operating experience (OE) that is relevant to the AMSE Code Class 1 components and to the SG secondary shell side components that are inspected and evaluated ASME Code Class 1 standards in ASME Code, Section XI Article IWB. The staff verified that the program is not credited for aging management of the ESF, Auxiliary System, and S&PC System components. RAI RCS-2 is resolved with respect to the operating experience review performed by the applicant for the ASME Code Class 1 components and the SG secondary shell-side components.

In RAI RCS-1, as issued relative to the applicant's Inservice Inspection Program, the staff asked the applicant to provide relevant operating experience information or CRs on borated water leakage, Class 1 seal housing bolt cracking, steam generator (SG) tube indications, and RV closure head weld indications that the staff had determined were applicable to the application.

The applicant responded to RAI RCS-1 by letter dated June 5, 2008. In its response, the applicant clarified that relevant condition reports existed that demonstrated applicable age-related degradation events for the following ASME Code Class 1 components:

- Boric acid leakage events for control rod drive (CRDs), CRD mechanisms, resistance temperature devices, RV lower head BMI nozzles, and RV seal tables, penetrations, fittings, and thimble tubes.
- Seal housing bolt cracking events
- SG tube indications
- Upper RV closure head weld indications

The staff has evaluated the boric acid leakage OE relative to the "operating experience" program element of AMP B.1.5, Boric Acid Corrosion Prevention Program. The staff evaluation of the "operating experience" program element of the Boric Acid Corrosion Prevention Program is given in SER Section 3.0.3.1.1 and includes the staff's basis for concluding that the system walkdowns and bare metal visual examinations of the Boric Acid Corrosion Prevention Program, as implemented through the Inservice Inspection Program, bound this operating experience and are capable of managing boric acid leakage and potential loss of material in steel ASME Class 1 components as a result of boric acid induced corrosion and wastage.

The staff evaluated the OE related to SG tube indications relative to the "operating experience" program element of AMP B.1.35, Steam Generator Integrity Program. The staff evaluation of the "operating experience" program element of the Steam Generator Integrity Program is given in SER Section 3.0.3.2.14 and includes the staff's basis for concluding that the inservice inspections that are performed in accordance with the Steam Generator Integrity Program, as implemented through the Inservice Inspection Program, bound this operating experience and are capable of managing loss of material and cracking in SG tubes, tubesheets and support plates.

In regard to the OE related to cracking in the upper RV closure head welds, the applicant stated that a recordable indication was detected in the #2 meridional weld of the IP3 upper RV closure head as a result of an ISI volumetric examination that was performed on the weld during the 2005 refueling outage. The applicant stated that the indication was similar to the indication from the original pre-service inspection record for the weld, which indicated that the indication was not from cracking and was acceptable for service. The applicant stated that the indication was recorded to allow for comparisons to be made during future inservice inspections of the components. The applicant also stated that the remaining five meridional welds in the head were examined but the inspections were negative for recordable indications. The monitoring and trending activities and acceptance criterion comparisons taken by the applicant to compare the inspection results of the #2 meridional weld to past pre-service inspection results and to expand the sample size to the remaining meridional welds in the IP3 head are in compliance with ASME Code, Section XI requirements and demonstrate that the applicant is taking appropriate measures to assess relevant recordable indications for acceptability. Based on this review, the staff finds that applicant has appropriately addressed the OE relative to the #2 meridional weld in the IP3 upper RV closure head and that the applicant's Inservice Inspection Program bounds this OE because the steps taken to evaluated the recordable indication and expand the sample size of inspections performed on the meridional welds of the IP3 upper RV closure head are in compliance with ASME Code, Section XI requirements.

The staff evaluated the OE related to seal housing bolt cracking relative to the "operating experience" program element of AMP B.1.2, Bolting Integrity Program. The staff evaluation of the "operating experience" program element of the Bolting Integrity Program is given in SER Section 3.0.3.2.2 and includes the staff's basis for concluding that the inservice inspections that are performed on these Class 1 bolting component, as performed in accordance with the Bolting Integrity Program and implemented through the Inservice Inspection Program, bound this operating experience and are capable, in part, of managing cracking in ASME Code Class 1, 2, and 3 bolting, including the Class 1 seal housing bolts.

Based on this review, and the discussions in the previous four paragraphs, the staff finds the applicant has accounted for the OE relative to Class 1 components discussed in RAI RCS-1 and that the inspections of the Boric Acid Corrosion Prevention Program, the Steam Generator Integrity Program, the Reactor Vessel Head Penetration Inspection Program, or Bolting Integrity Program are bounding for the operation experience on these components and are capable of managing the applicable aging effects that are within the scope of the CRs on the operating experience. RCS-1 is resolved relative to the relationship of this OE to the Inservice Inspection Program.

Based on this review, the staff confirmed that the "operating experience" program element satisfies the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.17 and A.3.1.17, the applicant provided the UFSAR supplement for the Inservice Inspection Program. The staff noted the UFSAR Supplement summary descriptions provided in LRA Sections A.2.1.17 and A.3.1.17 incorporated the recommended summary description criteria from the SRP-LR that the "program consists of periodic volumetric, surface, and/or visual examination of components and their supports for assessment, signs of degradation, and corrective actions." However, the staff noted that the applicant's summary description also incorporated the applicant's proposal to enhance the program for lubrite components, as provided in LRA Commitment 11, which references these

UFSAR Supplement sections.

In response to RAI 3.0.3.3.4-1 and Open Item 3.0.3.3.4-1, dated January 27, 2009, the applicant clarified that the inspection criteria, acceptance criteria, and corrective action criteria for the RCP and SG lubrite sliding supports would be implemented in accordance with the ISI requirements for ASME Code Class non-piping component supports in the ASME Code, Section XI, Article IWF. Based on this clarification, the staff finds that the applicant has fulfilled Commitment No 11 on specifying the inspection methods, frequency, sample size, acceptance criteria and corrective actions for the lubrite component supports and that the UFSAR Supplement summary descriptions for the applicant's Inservice Inspection Program are acceptable because they clarify that the Inservice Inspection Program will be implemented in accordance with the requirements of the ASME Code, Section XI, and 10 CFR 50.55a. The staff concludes that the issues raised in RAI 3.0.3.3.4-1 concerning UFSAR Supplement Summary Sections A.2.1.17 and A.3.1.17 are resolved and Open Item 3.0.3.3.4-1 is closed.

The staff reviewed LRA Sections A.2.1.17 and A.3.1.17 and finds the UFSAR supplement contains an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Inservice Inspection Program, the staff concludes that the applicant has demonstrated that effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program, and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.5 Nickel Alloy Inspection Program

Summary of Technical Information in the Application. LRA Section B.1.21 describes the existing Nickel Alloy Inspection Program as a plant-specific program.

The Nickel Alloy Inspection Program manages aging effects of Alloy 600 items and 82/182 welds in the reactor coolant system not addressed by the Reactor Vessel Head Penetration Inspection Program or the Steam Generator Integrity Program. The aging effect requiring management for nickel alloys exposed to borated water at an elevated temperature is PWSCC. The Nickel Alloy Inspection Program includes elements of the Inservice Inspection Program, which specifies the NDE techniques and acceptance criteria for evaluation of cracks, and of the Boric Acid Corrosion Control Program. The Water Chemistry Control - Primary and Secondary Program maintains primary water in accordance with EPRI guidelines to minimize potential crack initiation and growth. Indian Point will continue to implement commitments to (a) NRC orders, bulletins, and generic letters addressing nickel alloys and (b) staff-accepted industry guidelines.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in LRA Section B.1.21 on the applicant's demonstration of the Nickel Alloy Inspection Program to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

The staff reviewed the Nickel Alloy Inspection Program against the staff's recommended program element criteria that are provided in SRP-LR Section A.1.2.3, and in SRP-LR

Table A.1-1. The staff focused its review on assessing how the plant-specific program elements for the Nickel Alloy Inspection Program would ensure adequate aging management when compared to the recommended program element criteria that are given in SRP-LR Section A.1.2.3. Specifically, the staff reviewed the following seven program elements of the applicant's program: (1) "scope of the program," (2) "preventive actions," (3) "parameters monitored or inspected," (4) "detection of aging effects," (5) "monitoring and trending," (6) "acceptance criteria," and (10) "operating experience."

The applicant indicated that program elements (7) "corrective actions," (8) "confirmation process," and (9) "administrative controls" are parts of the site-controlled QA program. The staff evaluates the Nickel Alloy Inspection Program's "corrective actions," "confirmatory process" and "administrative controls" program elements as part of the staff's evaluation of the applicant's Quality Assurance Program. The staff's evaluation of the applicant's Quality Assurance Program is given in SER Section 3.0.4. The staff's evaluation of the remaining program elements are given in the paragraphs that follow:

(1) Scope of the Program - LRA Section B.1.21 states that the following reactor vessel and reactor coolant system pressure boundary items are within the scope of the Nickel Alloy Inspection Program:

- Reactor inlet and outlet nozzle safe end weld material
- Reactor bottom mounted instrumentation tubes
- Reactor core support lugs (pads)
- Reactor closure head vent safe ends and welds
- Reactor head vent and Reactor flange leakoff piping

SRP-LR Section A.1.2.3.1 states: "The specific program necessary for license renewal should be identified. The scope of the program should include the specific structures and components of which the program manages the aging."

GALL Report XI.M11, "Nickel-Alloy Nozzles and Penetrations," denotes that this AMP has been replaced in part by AMP 11A, "Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors (PWRs only)," and that guidance for the aging management of other nickel-alloy nozzles and penetrations is provided in the AMR line items of GALL Report Chapter IV, as appropriate.

Guidance for the aging management of other nickel-alloy nozzles and penetrations is provided in the AMR line items of Chapter IV, "Reactor Vessel, Internals, and Reactor Coolant System," as appropriate in the GALL Report. The items applicable to nickel-alloy material in Westinghouse reactors are found within sections A2, "Reactor Vessel (Pressurized Water Reactor)," B2, "Reactor Vessel Internals (PWR) – Westinghouse," C2, "Reactor Coolant System and Connected Lines (Pressurized Water Reactor)," and D1, "Steam Generator (Recirculating)."

The staff verified that the materials in the IP pressurizer nozzles and welded joints are not fabricated from Alloy 82/182/600 materials. The staff also verified the reactor coolant system contained no additional nickel alloy welds from those identified above. The staff also noted there have been numerous RAIs based on the review of the AMRs associated with the nickel alloy components. The staff determined that satisfactory resolution of RAI 3.1.2-1 is necessary for confirmation of the "scope of the program."

This was identified as part of Open Item 3.1.2-1.

The applicant responded to RAI 3.1.2-1 in a letter dated January 27, 2009. In this response, the applicant clarified that the following ASME Code Class 1 reactor coolant pressure boundary components are fabricated from Alloy 600 base metal materials or Alloy 82 or 182 weld filler metals:

- CRDM housing tubes (i.e., the CRDM nozzles)
- CRDM housing-to-housing tube safe-end adapter full penetration welds
- CRDM housing tube-to-upper reactor vessel closure head (RVCH) partial penetration welds
- upper RVCH vent adapter
- upper RVCH vent adapter-to-heat vent full penetration weld
- reactor vessel (RV) bottom mounted instrumentation (BMI) nozzles
- RV BMI nozzle-to-nozzle safe-end welds

The staff noted that these components are ASME Code Class 1 pressure boundary components and welds that are within the scope of B.1.21, Nickel Alloy Inspection Program. Based on this clarification, the staff finds that the applicant has resolved the issues raised in RAI 3.1.2-1 concerning the "scope of program" element for this AMP. The staff concludes that RAI 3.1.2-1 is resolved and Open Item 3.1.2-1 is closed with respect to the applicant's identification of nickel alloy base metal and weld components that are within the scope of the Nickel Alloy Inspection Program.

The staff also verified that the augmented inspection basis for the nickel alloy CRDM housing tubes (i.e., CRDM penetration nozzles) and their nickel alloy partial penetration upper RVCH-to-housing tube welds are within the scope of the applicant's Reactor Vessel Head Penetration Inspection Program (LRA AMP B.1.31). The staff's evaluation of the ability of the Reactor Vessel Head Penetration Program to manage cracking in the CRDM housing tubes and their nickel alloy upper RVCH-to-housing tube welds is in SER Section 3.0.3.1.12.

Based on this review, the staff confirmed that the "scope of the program" program element satisfies the guidance in SRP-LR Section A.1.2.3.1. The staff finds this program element acceptable.

(2) Preventive Actions - LRA Section B.1.21 states that "[n]o actions are taken as part of this program to prevent aging effects or mitigate aging degradation. However, primary water chemistry is maintained in accordance with EPRI guidelines by the Water Chemistry Control – Primary and Secondary Program, which minimizes the potential for PWSCC."

For condition monitoring program, SRP-LR Section A.1.2.3.2 states: "For condition or performance monitoring programs, they do not rely on preventive actions and thus, this information need not be provided."

The staff found that the Nickel Alloy Inspection Program uses nondestructive and visual examination methods to monitor the aging of the nickel alloy components as required by the ISI program and as augmented by the recommendations of applicable bulletins, generic letters and NRC approved industry guidance.

Based on this review, the staff confirmed that the “preventive actions” program element satisfies the guidance in SRP-LR Section A.1.2.3.2. The staff finds this program element acceptable.

(3) Parameters Monitored or Inspected - LRA Section B.1.21 states that “the Nickel Alloy Inspection Program detects degradation by using the examination and inspection requirements of ASME Section XI, augmented as appropriate by examinations in response to NRC Orders, Bulletins and Generic Letters, or to accepted industry guidelines. The parameters monitored are the presence and extent of cracking.”

For condition monitoring programs, SRP-LR Section A.1.2.3.3 states:

“The parameters to be monitored or inspected should be identified and linked to the degradation of the particular structure and component intended function(s),” and “[f]or a condition monitoring program, the parameter monitored or inspected should detect the presence and extent of aging effects. Some examples are measurements of wall thickness and detection and sizing of cracks.”

The staff notes that the Nickel Alloy Inspection Program uses the appropriate volumetric, surface and visual NDE techniques for detection of degradation of the components identified in the scope of the program as required by ASME Code and recommended by the applicable bulletins, generic letters and industry guidance.

Based on this review, the staff confirmed that the “parameters monitored or inspected” program element satisfies the guidance in SRP-LR Section A.1.2.3.3. The staff finds this program element acceptable.

(4) Detection of Aging Effects - LRA Section B.1.21 states that “the Nickel Alloy Inspection Program detects cracking due to PWSCC prior to loss of component intended function. Some of the nickel alloy locations receive volumetric, surface and visual examination in accordance with ASME Section XI, supplemented as appropriate for current industry PWSCC considerations. Items receiving volumetric, surface and visual examination are listed below.

- Reactor vessel nozzle-to-safe end dissimilar metal welds receive a visual inspection every other outage and examination by volumetric techniques at 10-year intervals per ASME Section XI, Examination Category B-F.
- Bottom mounted instrumentation nozzles receive a visual examination from the exterior of the vessel in accordance with ASME Section XI, Examination Category B-P.
- The core support pads and guide lugs receive a visual examination in accordance with ASME Section XI, Examination Category B-N-2.
- The head vent and reactor flange leakoff piping receive a visual examination.

The EPRI MRP in conjunction with the Westinghouse owners groups (WOG) is developing a strategic plan to manage and mitigate PWSCC of nickel based alloy items. The main goal of this program will be to provide short and long term guidance for inspection, evaluation, and management of nickel alloy material and weld metal locations in PWR primary systems. Guidance developed by the MRP and WOG will be used to identify critical locations for inspection and augment existing ISI inspections where appropriate."

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.4.

The staff noted that specific techniques and frequencies for monitoring the nickel alloy components are prescribed by ASME Code, Section XI for those components examined in accordance with the ISI program. For the other items included in the scope of the Nickel Alloy Inspection program the methods and frequencies of examination are recommended in the applicable bulletins, generic letters and industry guidance.

Based on this review, the staff confirmed that the "detection of aging effects" program element satisfies the guidance in SRP-LR Section A.1.2.3.4. The staff finds this program element acceptable.

(5) Monitoring and Trending - LRA Section B.1.21 states that "Records of the inspection program, examination and test procedures, examination/ test data, and corrective actions taken or recommended are maintained in accordance with the requirements of ASME Section XI, Subsection IWA."

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.5.

The staff noted that ASME Section XI requires, "recording of examination and test results that provide a basis for evaluation and facilitate comparison with the results of subsequent examinations." ASME Section XI also requires, "retention of all inspection, examination, test, and repair/replacement activity records and flaw evaluation calculations for the service lifetime of the component or system." ASME Section XI additionally provides rules for "additional examinations" (i.e., sample expansion), when flaws or relevant conditions are found that exceed the applicable acceptance criteria, to assist in determination of an extent of condition and causal analysis.

Based on this review, the staff confirmed that the "monitoring and trending" program element satisfies the guidance in SRP-LR Section A.1.2.3.5. The staff finds this program element acceptable.

(6) Acceptance Criteria - LRA Section B.1.21 states that "Acceptance criteria for the volumetric inspections of dissimilar metal welds will be in accordance with ASME Section XI, IWB-3514. The acceptance standards for visual examination are specified in MRP-139. Acceptance standards for visual inspection of the core support pads are given in IWB-3520. Acceptance criteria for identified external surface damage, such as from borated water leaks, are given in ASME Section XI, IWA-5250. Should additional inspections (volumetric, surface or visual) of nickel-based alloy locations (weld and base metal) be identified based on industry operating experience, where acceptance standards are not included in ASME Section XI, acceptance standards will be developed using appropriate analytical techniques."

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.6.

The staff noted that ASME Section XI, IWB-3000, contains acceptance criteria appropriate for the reactor coolant pressure boundary components examined in accordance with Section XI. Also, ASME Section XI, IWA-5250, was verified to contain acceptable steps for evaluation and corrective measures for sources of leakage identified by visual examinations for leakage.

Based on this review, the staff confirmed that the “acceptance criteria” program element satisfies the guidance in SRP-LR Section A.1.2.3.6. The staff finds this program element acceptable.

(10) Operating Experience - LRA Section B.1.21 states that:

> The Nickel Alloy Inspection Program incorporates proven monitoring techniques and acceptance criteria for detection of cracking in nickel alloy components prior to a loss of function. Reactor coolant pressure boundary inspections have found no indications of cracking of nickel alloy components. The program considers industry operating experience, responds to industry trends in inspection, evaluation, repair, and mitigation activities, and is structured to be compatible with corresponding programs across the industry. In response to NRC Bulletin 2003-02, there were bare-metal visual examinations of the lower head of the reactor vessel in the fall of 2004 for IP2 and in the spring of 2005 for IP3. Examination of the area adjacent to each bottom-mounted instrumentation penetration, including each Alloy 600 penetration, the nickel alloy weld pad, and the circumference around the annulus between the penetration and weld pad, detected no cracking.

The staff confirms that the “operating experience” program element satisfies the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.20 and A.3.1.20, the applicant provided the UFSAR supplement for the Nickel Alloy Inspection Program. The staff reviewed these sections and finds the UFSAR supplement information an adequate summary description of the program, as required by 10 CFR 54.21(d).

UFSAR Supplement A.2.1.41, “Reactor Vessel Internals Aging Management Activities,” includes a commitment that the site will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.

By letter dated June 11, 2008, the applicant revised the statement in the UFSAR Supplement sections A.2.1.20 and A.3.1.20 to incorporate the response to RAI 3.0.3.3.5-2 and stated IP would comply with future applicable NRC Orders and implement applicable (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines associated with nickel alloys. The staff finds this to be acceptable because it is consistent with the aging management review basis for non-upper RVCH nozzle nickel alloy components, as provided in Table IV.A2 of the

GALL Report, Volume 2, and the criteria in SRP-LR Section 3.1.3.2.13.

Conclusion. On the basis of its review of the applicant's Nickel Alloy Inspection Program, the staff concludes that the applicant has demonstrated that effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.6 Non-EQ Bolted Cable Connections Program

Summary of Technical Information in the Application. LRA Section B.1.22 describes the new Non-EQ Bolted Cable Connections Program as a plant-specific program. The applicant stated that this program provides for one-time inspections on a sample of connections to be completed prior to the period of extended operation. The factors considered for sample selection will be application (medium and low voltage defined as less than 35kV), circuit loading (high loading), and location (high temperature, high humidity, vibration, etc.). The technical basis for the sample selections will be documented. If an unacceptable condition or situation is detected in the selected sample, the corrective action program will evaluate the condition and determine appropriate corrective action. The applicant also stated that this program will ensure that electrical cable connections perform intended functions through the period of extended operation and will be implemented prior to it.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in LRA Section B.1.22 on the applicant's demonstration of the Non-EQ Bolted Cable Connections Program to ensure that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

The staff reviewed the Non-EQ Bolted Cable Connections Program against the AMP elements found in the GALL Report, in SRP-LR Section A.1.2.3, and in SRP-LR Table A.1-1, focusing on how the program manages aging effects through the effective incorporation of 10 elements ((1) "scope of the program," (2) "preventive actions," (3) "parameters monitored or inspected," (4) "detection of aging effects," (5) "monitoring and trending," (6) "acceptance criteria," (7) "corrective actions," (8) "confirmation process," (9) "administrative controls," and (10) "operating experience").

The applicant indicated that program elements (7) "corrective actions," (8) "confirmation process," and (9) "administrative controls" are parts of the site-controlled QA program. The staff's evaluation of the QA program is in SER Section 3.0.4. Evaluation of the remaining seven elements follows:

(1) Scope of the Program - LRA Section B.1.22 states that non-EQ connections associated with cables in the scope of license renewal are part of this program. This program does not include the high voltage (greater than 35kV) switchyard connections. In-scope connections are evaluated for applicability of this program. The criteria for including connections in the program are that the connection is a bolted connection that is not covered under the EQ program or an existing preventive maintenance program.

    SRP-LR Appendix A.1.2.3.1 states that the program scope includes the specific structures and components of which the program manages the aging.

The staff confirmed that the specific commodity groups for which the program manages aging effects are identified (Non-EQ bolted cable connections associated with cables within the scope of license renewal), which satisfies the guidance in SRP-LR Appendix A.1.2.3.1. The staff also determined that the exclusion of high-voltage (>35 kV) switchyard connections, connections covered under EQ program and the existing PM program is acceptable. Switchyard connections are addressed in SER Section 3.6.2.2. EQ cable connections are covered under 10 CFR 50.49. Cable connections under a preventive maintenance program are periodically inspected. On this basis, the staff finds that the applicant's "scope of program" program element is acceptable.

(2) Preventive Actions - LRA Section B.1.22 states that this one-time inspection program is a condition monitoring program; therefore, no actions are taken as part of this program to prevent or mitigate aging degradation.

SRP-LR Appendix A.1.2.3.2 states that condition monitoring programs do not rely on preventive actions, and thus, preventive actions need not be provided.

The staff confirmed that the preventive actions program element satisfies the guidance in SRP-LR Appendix B.1.2.3.2. The staff finds it acceptable because this is a condition monitoring program and there is no need for preventive actions. On this basis, the staff finds the applicant's "preventive actions" program element is acceptable.

(3) Parameters Monitored or Inspected - LRA Section B.1.22 states that this program will focus on the metallic parts of the cable connections. The one-time inspection verifies that loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation is not an aging effect that requires a periodic aging management program.

SRP-LR Appendix A.1.2.3.3 states that the parameters to be monitored or inspected should be identified and linked to the degradation of the particular structure and component intended function(s). The parameter monitored or inspected should detect the presence and extent of aging effects.

The staff confirmed that the parameters monitored/inspected program element satisfies the guidance in Appendix A.1.2.3.3 of the SRP-LR. Loosening (or high resistance) of bolted cable connections are the potential aging effects due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation. The design of bolted cable connections usually account for the above stressors. The one-time inspection is to confirm that these stressors are not an issue that requires a periodic AMP. On this basis, the staff finds that the applicant's "parameters monitored or inspected" program element is acceptable.

(4) Detection of Aging Effects - LRA Section B.1.22 states that a representative sample of electrical connections within the scope of license renewal and subject to aging management review will be inspected or tested prior to the period of extended operation to verify there are no aging effects requiring management during the period of extended operation. The applicant stated that factors considered for sample selection will be application (medium and low voltage), circuit loading (high loading), and location (high temperature, high humidity, vibration, etc.). The technical basis for the sample selected

will be documented. Inspection methods may include thermography, contact resistance testing, or other appropriate methods including visual based on plant configuration and industry guidance. The applicant also stated that one-time inspection provides additional confirmation to support industry operating experience that shows that electrical connections have not experienced a high degree of failures, and that existing installation and maintenance practices are effective.

SRP-LR Appendix A.1.2.3.4 states that detection of aging effects should occur before there is a loss of the structure and component intended function(s). The parameters to be monitored or inspected should be appropriate to ensure that the structure and component intended functions will be adequately maintained for license renewal under all CLB design conditions.

The GALL Report AMP XI.E6 states that testing may include thermography, contact resistance testing, and other appropriate testing methods. In AMP B.1.22, the applicant states that inspection methods may include thermography, contact resistance testing, or other appropriate methods including visual inspection based on plant configuration and industry guidance. The staff requested the applicant to explain how visual inspection alone, if used, can detect loosening of bolted connections (Audit Item 63). In a letter dated December 18, 2007, the applicant responded that visual inspection is an alternate technique to thermography or measuring connection resistance of bolted connections that are covered with heat shrink tape, sleeving, insulating boots, etc., where the only alternative to visual inspection is destructive examination. The applicant also stated that an example of where visual inspection may be used is motor connections, where the motor lead is connected to the field cable in a local junction box. Typically these connections are completely covered with field splices, so there is no method to perform connection resistance testing of the connection. The practice would be to not remove the junction box cover when the cable is energized, so thermography would not be an option to determine a loose connection. Another example of using visual inspection would be in remote switchgear panels where the entire connection to the bus is covered with tape or an insulating boot.

In a letter dated March 24, 2008, the applicant supplemented its response and stated that because of personal safety practices, the junction box cover would not be removed when the cable is energized, so thermography could only be performed with the junction box in place, which may not provide accurate results. Contact resistance measurements would require the destructive examination of the connection. The applicant's policies for personnel safety for energized components at a potential greater than 600V are to observe a restricted approach boundary, which would preclude the removal of a bolted cover from energized components at a potential of greater than 600V. The applicant stated that numbers of bolted connections that are greater than 600V are limited to large motor, transformer, or generator connections (less than 30 connections, which are 3 connections per phase for 10 motors) for both units and 5 remote motor control centers for both units.

On August 29, 2007, the staff issued proposed license renewal interim staff guidance LR-ISG-2007-02, "Changes to Generic Lesson Learned (GALL) Report Aging Management Program (AMP) XI.E6, 'Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements,'" for public comment. In this ISG, the staff proposed changes to GALL AMP XI.E6 to clarify and recommend a one-time inspection, on a representative sampling, to ensure that either aging of metallic cable connections is not occurring or an existing preventive maintenance program is effective, such that a periodic testing is not required. Based on public and stakeholder comments, the staff has determined that resistance measurement or thermography may be a preferred method for testing loose cable connections. However, if resistance measurement can not be performed with the insulation in place, and for reasons of personnel safety, energized equipment can not be accessed to perform thermography, then visual inspection is an acceptable alternate inspection method for cable connections covered with insulation materials. The staff has previously permitted visual inspections every 5 years for covered bus connections in GALL XI.E4, Metal Enclosed Bus. If the applicant chooses visual inspection as an alternate to thermography or resistance measurement of cable connections covered with insulating materials (heat sink tapes, sleeving, insulation boots etc.), it can not use a one-time inspection and must perform periodic visual inspections. Periodic visual inspection can effectively detect loosening of cable connections by inspecting insulation materials for discoloration, cracking, chipping, or surface contamination. Absence of insulation deterioration will ensure that cable connections will not be loose. The staff is finalizing its position in the final ISG to permit periodic visual inspections for cable connections covered with insulation.

In a letter dated August 14, 2008, the applicant stated that following a telephone conference call held on June 2, 2008, with the NRC, Entergy agreed that visual inspections would not be used for one-time inspections in the Indian Point Non-EQ Bolted Cable Connection Program and the applicant revised LRA Section B.1.22 as follows:

> B.1.22 Non-EQ Bolted Cable Connection Program, Detection of Aging Effects. A representative sample of electrical connections within the scope of license renewal and subjected to aging management review will be inspected or tested prior to the period of extended operation to verify there are no aging effects requiring management during the period of extended operation. The factors considered for sample selection will be application (medium and low voltage), circuit loading (high loading), location (high temperature, high humidity, vibration, etc.). The technical basis for the sample selected will be documented. Inspection methods may include thermography, contact resistance testing, or other appropriate methods based on plant configuration and industry guidance. The one-time inspection provides additional confirmation to support industry operating experience that shows that electrical connections have not experienced a high degree of failures, and that existing installation and maintenance practice are effective.

The staff finds the applicant supplemental response acceptable because the applicant committed to inspect or test a representative sample of electrical connections using methods such as thermography, contact resistance testing, or other appropriate methods. Resistance measurement or thermography is a preferred method for testing loose cable connections. These test methods are consistent with those in the GALL Report AMP XI.E6. On this basis, the staff finds that the applicant’s description of “parameters monitored or inspected” program element is acceptable.

(5) Monitoring and Trending - LRA Section B.1.22 states that trending actions are not included as part of this program because this is a one-time inspection program.

SRP-LR Appendix A.1.2.3.5 states that monitoring and trending activities should be described, and they should provide predictability of the extend of degradation and thus affect timely corrective or mitigative actions. This program element describes how the data collected are evaluated and may also include trending for a forward look. The parameter or indicator trended should be described.

The staff confirmed that absence of trending for testing is acceptable since the test is a one-time inspection and the ability of trending is limited by the available data. Furthermore, the staff did not see a need for such activities. On this basis, the staff finds the applicant's "monitoring and trending" program element is acceptable.

(6) Acceptance Criteria - LRA Section B.1.22 states that the acceptance criteria for each inspection / surveillance are defined by the specific type of inspection or test performed for the specific type of cable connections. Acceptance criteria ensure that the intended functions of the cable connections can be maintained consistent with the CLB.

SRP-LR Appendix A.1.2.3.6 states that the acceptance criteria of the program and its basis should be described. The acceptance criteria, against which the need for corrective actions will be evaluated, should ensure that the structure and component intended functions are maintained under all CLB design conditions during the period of extended operation.

The staff confirmed that this program element satisfies the guidance in Appendix A.1.2.3.6 of the SRP-LR. The staff finds it acceptable on the basis that acceptance criteria for inspection/surveillance are defined by the specific type of inspection or test performed for the specific type of connection. The specific type of test when implemented, and acceptance criteria will ensure that the license renewal intended functions of the cable connections will be maintained consistent with the current licensing basis.

(10) Operating Experience - LRA Section B.1.22 states that operating experience shows that loosening of connections and corrosion of connections could be a problem without proper installation and maintenance. The applicant stated that industry operating experience supports this one-time inspection program in lieu of a periodic testing program to verify whether installation and maintenance have been effective. The Non-EQ Bolted Cable Connections Program is new. The applicant will consider industry operating experience when implementing this program.

SRP-LR Appendix A.1.2.3.10 states that operating experience should provide objective evidence to support the conclusion that the effect of aging will be managed adequately so that the structure and component intended functions will be maintained during the period of extended operation.

The staff notes that only a limited number of cases related to failed connections due to aging have been identified and these operating experiences do not support a periodic inspection as currently recommended in GALL AMP XI.E6. On August 29, 2007, the staff issued proposed license renewal interim staff guidance LR-ISG-2007-02, Changes to Generic Lesson Learned (GALL) Report Aging Management Program (AMP) XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements" for public comments. In this ISG, the staff proposed changes to GALL AMP XI.E6 to clarify and recommend a one-time inspection, on a representative sampling, to ensure that either aging of metallic cable connections is not occurring or an existing preventive maintenance program is effective, such that a periodic testing is not required. The staff agreed with the applicant's assessment of operating experience. The staff finds that the proposed one-time inspection program will ensure that either aging of metallic cable connections is not occurring or the existing preventive maintenance program is effective such that a periodic inspection program is not required. On this basis, the staff finds that the applicant's operating experience element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.21 and A.3.1.21, the applicant provided the UFSAR supplement for the Non-EQ Bolted Cable Connections Program. The staff reviewed these sections and finds the UFSAR supplement information an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Non-EQ Bolted Cable Connections Program, the staff concludes that the applicant has demonstrated that effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.7 Periodic Surveillance and Preventive Maintenance Program

Summary of Technical Information in the Application. LRA Section B.1.29, as amended by letters dated December 18, 2007, August 14, 2008, January 27, 2009, June 12, 2009, and June 30, 2009, describes the existing Periodic Surveillance and Preventive Maintenance Program as a plant-specific program.

Periodic inspections and tests in the Periodic Surveillance and Preventive Maintenance Program manage aging effects not managed by other AMPs. The Periodic Surveillance and Preventive Maintenance Program enhancements add new activities to the plant's preventive maintenance and surveillance programs, which generally implement preventive maintenance and surveillance testing activities through repetitive tasks or routine monitoring of plant operations. Visual and other NDE techniques inspect the following systems and structures:

- reactor building
- safety injection system
- main steam system
- circulating water system
- city water system
- condensate system
- river water system
- fresh water cooling system
- wash water system
- chemical and volume control system
- plant drains
- station air system
- instrument air system

- heating, ventilation, and air conditioning (HVAC) systems
- emergency diesel generators
- security generator system
- IP2 SBO/Appendix R diesel generator
- fuel oil system
- IP3 Appendix R diesel generator
- auxiliary feedwater
- containment cooling and filtration
- control room HVAC
- nonsafety-related systems affecting IP2 safety-related systems
- nonsafety-related systems affecting IP3 safety-related systems

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in LRA Section B.1.29 on the applicant's demonstration of the Periodic Surveillance and Preventive Maintenance Program to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

The staff reviewed the Periodic Surveillance and Preventive Maintenance Program against the AMP elements found in the GALL Report, in SRP-LR Section A.1.2.3, and in SRP-LR Table A.1-1, focusing on how the program manages aging effects through the effective incorporation of 10 elements ((1) "scope of the program," (2) "preventive actions," (3) "parameters monitored or inspected," (4) "detection of aging effects," (5) "monitoring and trending," (6) "acceptance criteria," (7) "corrective actions," (8) "confirmation process," (9) "administrative controls," and (10) "operating experience").

The applicant indicated that program elements (7) "corrective actions," (8) "confirmation process," and (9) "administrative controls" are parts of the site-controlled QA program. The staff's evaluation of the QA program is in SER Section 3.0.4. Evaluation of the remaining seven elements follows:

(1) Scope of the Program - LRA Section B.1.29 states that the "IPEC Periodic Surveillance and Preventive Maintenance Program, with regard to license renewal, includes those tasks credited with managing aging effects identified in aging management reviews."

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.1.

The staff noted that the applicant had identified this AMP as a plant-specific AMP that does not have a GALL Report counterpart. The staff also noted that, of the aging management activities mentioned in the program description, the applicant had identified that the applicant had identified that the majority of the activities were new, and that for these activities, the "scope of program," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements for the AMP are enhanced as follows:

"Program activity guidance documents will be developed or revised as necessary to assure that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation."

The applicant included this enhancement in Commitment 21 (refer to the letter of March 24, 2008). Because the Periodic Surveillance and Preventive Maintenance Program is a plant-specific AMP, the program activities for the components within the scope of the AMP should be defined in the program element discussions that are provided in the LRA for the AMP.

The staff noted that the "scope of program" program element for the Periodic Surveillance and Preventive Maintenance Program did not specify which components were within the scope of the program, although it did appear that the applicant had provided this type of information in the program description for the AMP. Thus, the staff was of the opinion that the applicant's "scope of program" program element for the Periodic Surveillance and Preventive Maintenance Program did not conform to the staff's general recommendation in SRP-LR Section A.1.2.3.1 because the applicant did not define the components that are within the scope of the program in its "scope of program" program element for the AMP. In RAI 3.0.3.3.7-1, Part 1, the staff informed the applicant that it would need to define the components and systems that are within the scope of the Periodic Surveillance and Preventive Maintenance Program. This was identified as Open Item 3.0.3.3.7-1, Part 1.

The applicant responded to RAI 3.0.3.3.7-1, Part 1 in a letter dated January 27, 2009. In this letter the applicant clarified that the components and systems within the scope of the "scope of program" program element for the Periodic Surveillance and Preventive Maintenance Program are those components and systems that have been identified in the program description for the AMP. The staff verified that the components and systems within the scope of the Periodic Surveillance and Preventive Maintenance Program are identified in the program description for the AMP, as amended by applicable system and component scoping information for this AMP that was provided by the applicant in letters dated December 18, 2007, and August 14, 2008.

The staff noted that in the applicant's letter dated December 18, 2007, the applicant amended the "scope of program" program element for the Periodic Surveillance and Preventive Maintenance Program to add the main steam safety valve tailpipes in the main steam system and the atmospheric dump valve silencers to the scope of the Periodic Surveillance and Preventive Maintenance Program.

The staff also noted that in the applicant's letter dated August 14, 2008, the applicant amended the "scope of program" program element for the Periodic Surveillance and Preventive Maintenance Program to add the IP2 138 kV underground transmission cable for the offsite power feeder to the scope of the Periodic Surveillance and Preventive Maintenance Program.

The staff confirmed that information provided by the applicant in LRA Section B.1.29, as amended in its letters dated December 18, 2007, August 14, 2008, January 27, 2009, June 12, 2009, and June 30, 2009, clarified that the following systems and components are within the scope of the Periodic Surveillance and Preventive Maintenance Program:

- reactor building: reactor building cranes (polar and manipulator), crane rails, and girders, and refueling platform
- safety injection (SI) system: recirculation pump motor cooling coils and housing

- city water system: piping, piping elements and piping components
- chemical and volume control system (CVCS): charging pump casings
- plant drains: piping, piping components, and piping elements in the drains, and for IP2, the backwater valves
- station air system: station air containment penetration piping
- heating, ventilation and air conditioning (HVAC) systems: HVAC duct flexible connections, stored portable blowers, and flexible trunks
- emergency diesel generator (EDG) systems: EDG exhaust gas piping, piping components and piping elements; EDG duct flexible connections; EDG air intake and aftercooler piping, piping components and piping elements; EDG air start piping, piping components and piping elements; and EDG cooling water makeup supply valves
- security generator system: security generator exhaust piping, piping components and piping elements; and security generator radiator tubes
- IP2 station blackout/fire protection diesel generator (SBO/Appendix R DG): SBO/Appendix R DG exhaust gas piping, piping components, and piping elements; SBO/Appendix R diesel engine turbocharger and aftercooler housing, including external surfaces of the tubes and fins; and SBO/Appendix R jacket water heat exchanger bonnet and tubes
- IP3 fire protection diesel generator (Appendix R DG): Appendix R DG exhaust gas piping, piping components, and piping elements; Appendix R DG radiator; Appendix R DG aftercooler; Appendix R starting air piping, piping components, and piping elements; and Appendix R DG crankcase exhaust subsystem piping, piping components and piping elements
- fuel oil system: SBO/Appendix R diesel fuel oil cooler, and the diesel fuel oil trailer transfer tank and associated valves
- auxiliary feedwater system: piping, piping components, and piping elements containment cooling and filtration system: containment cooling duct flexible connections; and containment cooling fan units, including damper housings, filter housings, moisture separators, and heat exchanger headers, housings, and tubes
- control room HVAC: condensers and evaporators; control room HVAC ducts and drip pans; and duct flexible connections
- IP2 non-safety system affecting safety systems (NSAS): piping, piping components, and piping elements in the circulating water system (including flexible elastomer piping), city water system, intake structure, EDG system, fresh water cooling water system, instrument air system, integrated liquid waste handling system, lube oil system, radiation monitoring system, river water service system, station air system, waste disposal system, wash water system, water treatment plant, and other miscellaneous NSAS piping systems
- IP3 NSAS: piping, piping components, and piping elements in the chlorination system, circulating water system (including flexible elastomer piping), EDG system, floor drain system, gaseous waste disposal system, instrument air system, liquid waste disposal system, nuclear equipment drain system, river water system, station air system, steam generator sampling system, and secondary plant sampling system
- IP2 and IP3 pressurizer relief tanks
- main steam safety valve tailpipes
- atmospheric dump valve silencers
- IP2 138 kV underground transmission cable for the offsite power feeder

- main condenser tube internal surfaces
- instrument air aftercooler tube internal surfaces
- fresh water/river water heat exchanger internal and external surfaces

Based on this verification, the staff finds that the applicant's "scope of program" element, as amended in the applicant's letter of December 18, 2007, August 14, 2008, January 27, 2009, June 12, 2009, and June 30, 2009, is acceptable because: (1) the amended basis clarifies which plant systems and components at IP2 and IP3 are within the scope of the Periodic Surveillance and Preventive Maintenance Program, and (2) the systems and components listed in the amended basis conform to the recommendation in SRP-LR Section A.1.2.3.1 that systems and components within the scope of an AMP should be identified in the "scope of program" program element for the AMP.

The staff concludes that RAI 3.0.3.3.7-1, Part 1 is resolved and Open Item 3.0.3.3.7-1, Part 1 is closed with respect to identifying the systems and components that are within the scope of the Periodic Surveillance and Preventive Maintenance Program.

Based on this review, the staff confirmed that the "scope of the program" program element satisfies the guidance in SRP-LR Section A.1.2.3.1.

(2) Preventive Actions - LRA Section B.1.29 states that "inspection and testing activities used to identify component aging effects do not prevent aging effects. However, activities are intended to prevent failures of components that might be caused by aging effects."

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.2.

The staff noted that the applicant has identified the Periodic Surveillance and Preventive Maintenance Program as a both an existing condition monitoring program and an existing performance monitoring program, and that the program does not include any aging management activities to prevent or mitigate the effects of aging that are applicable to the components within the scope of the AMP. Based on this review, the staff concludes that the applicant has provided an acceptable basis for concluding that the criterion in SRP-LR A.1.2.3.2 is not applicable to the Periodic Surveillance and Preventive Maintenance Program because the program is not a preventive or mitigative-based AMP and does not include any activities that are designed to prevent or mitigate the effects of aging.

The staff confirms that the "preventive actions" program element satisfies the guidance in SRP-LR Section A.1.2.3.2.

(3) Parameters Monitored or Inspected - LRA Section B.1.29 states that this program "provides instructions for monitoring structures, systems, and components to detect degradation. Inspection and testing activities monitor various parameters including system temperatures, wall thickness, surface condition, and signs of cracking."

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.3.

The staff noted that SRP-LR Section A.1.2.3.3 recommends that “parameters monitored or inspected” program element for AMPs is made to accomplish two objectives: (1) identify the aging effect(s) (degradation types) that the program manages, and (2) provide a link between the parameters that the program monitors for and the aging effect(s) the program is credited to manage. The staff noted that in the “parameters monitored or inspected” program element for the AMP, the applicant only mentioned “system temperatures, wall thickness, surface condition, and signs of cracking” as examples of the parameters that the program monitors for. The staff noted that, in the program description for the AMP, the applicant listed the following four (4) aging effects that the program monitors for: (1) cracking, (2) loss of material, (3) fouling, and (4) changes in material properties for elastomeric or polymeric (including rubber) materials. The staff noted, however, that, with the exception of cracking, the applicant did not identify the aging effects that are within the scope of the AMP and that AMP monitors or inspects for and that the applicant also did not specifically identify and link the specific parameters that the program monitors or inspects for to each of the aging effects that are within the scope of the program.

To address these issues, the staff issued RAI 3.0.3.3.7-1, Part 2. In this RAI, the staff asked to applicant to clarify which aging effects are managed by the Periodic Surveillance and Preventive Maintenance Program, which parameters are indicative of these aging effects and would be monitored for as part of the applicant’s implementation of the program, and which inspection techniques would be used to detect the parameters that are indicative of the applicable aging effects. This was identified as Open Item 3.0.3.3.7-1, Part 2.

By letter dated January 27, 2009, the applicant responded to RAI 3.0.3.3.7-1, Part 2. In this letter, the applicant included an aging effect monitoring table that: (1) identifies the particular aging effects that are managed by the Periodic Surveillance and Preventive Maintenance Program, (2) provides the aging mechanisms that could induce each of particular aging effects requiring management under the program, (3) provides the parameters that would be indicative of the particular aging effects that will be managed and monitored for under the AMP, and (4) provides the inspection techniques that would be used to detect the parameters that the applicant is monitoring for.

The table below summarizes the information provided in the applicant's aging effect monitoring table.

Parameters Monitored and Inspection Methods for Specific Aging Effects and Mechanisms			
Aging Effect	By Aging Mechanism	Parameter Monitored	Inspection Method
Loss of Material	Crevice Corrosion	Surface condition or wall thickness	Visual (VT-1 or equivalent) or or Volumetric (RT or UT)
	Galvanic Corrosion	Surface condition or wall thickness	Visual (VT-3 or equivalent) or Volumetric (RT or UT)
	General Corrosion	Surface condition or wall thickness	Visual (VT-3 or equivalent) or Volumetric (RT or UT)
	Microbiologically Influenced Corrosion (MIC)	Surface condition or wall thickness	Visual (VT-3 or equivalent) or Volumetric (RT or UT)
	Pitting Corrosion	Surface condition or wall thickness	Visual (VT-1 or equivalent) or Volumetric (RT or UT)
	Erosion	Surface condition or wall thickness	Visual (VT-3 or equivalent) or Volumetric (RT or UT)
Cracking	SCC or cyclical loading	Cracks	Enhanced Visual (VT-1 or equivalent) or Volumetric (RT or UT)
Cracking in elastomeric component s		Cracks	Visual (VT-3 or equivalent)
Changes in material properties of elastomeric component s		Hardening or Cracks	Visual (VT-3 or equivalent)

The staff found the clarifications and information provided in the aging effect monitoring table were acceptable, with certain exceptions, because the information was in conformance with the similar aging-effect-parameter combinations recommended for aging management in GALL AMP XI.M32, "One-Time Inspection." The exceptions in the applicant's aging effect monitoring table that needed further clarification are discussed and evaluated below.

The staff noted that in the applicant's letter of December 18, 2007, the applicant identified fouling as an aging mechanism and monitoring parameter that could be used to provide indication of a loss of material or loss of heat transfer capability in heat exchanger tubes or cooling coil fins that are within the scope of this AMP. The identification of fouling as an aging mechanism which can lead to a loss of material or a loss of heat transfer capability is consistent with GALL Report Table IX.F. Because the applicant's position is consistent with the recommendation in the GALL Report, the staff finds this acceptable.

The staff also noted that the aging effect monitoring table in the applicant's response to RAI 3.0.3.3.7-1, Part 2, indicated that elastomeric flexible connections would be monitored to detect cracking. The staff finds this to be acceptable because cracks in solid materials are extrinsic thermodynamic properties that can be directly monitored by inspection. The applicant also clarified that monitoring of cracks and the hardness of elastomeric components would be monitored for indications of any changes that might occur in the material properties of the elastomers during the period of extended operation. The staff finds this to be acceptable because the presence of a crack in the elastomeric material may provide an indirect indication on whether the material is undergoing embrittlement or is losing its elastic properties over time. In addition, the monitoring of hardness by flexible manipulation of the materials will be capable of demonstrating whether the elastomeric materials are degrading. Thus, the staff concludes that the applicant has established an acceptable basis for the parameters that will be used to monitor for cracking and/or changes of the material properties of elastomeric components.

Based on its review, the staff confirmed that the "parameters monitored or inspected" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.3. The staff concludes that RAI 3.0.3.3.7-1, Part 2 is resolved, and Open Item 3.0.3.3.7-1, Part 2 with respect to the acceptability of the "parameters monitoring or inspected" program element for this AMP is closed.

(4) Detection of Aging Effects - LRA Section B.1.29 states that:

> Preventive maintenance activities provide for inspections to detect aging effects. Periodic surveillances provide for testing to detect aging effects. Inspection and testing intervals are established such that they provide timely detection of degradation. Inspection and testing intervals are dependent on component material and environment and take into consideration industry and plant-specific operating experience and manufacturers' recommendations. Each inspection or test occurs at least once every five years with the exception of the following.
>
> - Components associated with emergency and Appendix R diesel generators are inspected every six years in accordance with manufacturer recommendations.
> - Appendix R diesel generator crankcase exhauster inspection is every ten years in accordance with manufacturer recommendations.
> - Copper alloy components exposed to city water are inspected every ten years since city water is treated per New York State requirements and aging effects are not expected.
> - The internals of each pressurizer relief tank are inspected every ten years since the tank is coated.
>
> The extent and schedule of inspections and testing assure detection of component degradation prior to loss of intended functions. Established techniques such as visual inspections or NDE are used. In cases where a representative sample is inspected by this program, the sample size will be based on Chapter 4 of EPRI document 107514, Age Related Degradation Inspection Method and Demonstration, which outlines a

method to determine the number of inspections required for 90 percent confidence that 90 percent of the population does not experience degradation (90/90). Each group of components with the same material-environment combination is considered a separate population. The program provides for increasing inspection sample size in the event that aging effects are detected. Unacceptable inspection findings are evaluated in accordance with the IPNG corrective action process to determine the need for accelerated inspection frequency and for monitoring and trending the results.

The staff compared this program element against the criteria in SRP-LR Section A.1.2.3.4.

The staff noted that the applicant's "detection of aging effects" program element did identify that either visual examinations or NDE would be performed on the specific system components that are within the scope of the AMP at any inspection interval of at least once every five years with the following exceptions:

- Appendix R fire protection diesel generators: passive components inspected at least once every 6 years in accordance with manufacturer recommendations, with the exception of the crank case exhaust piping components once every 10 years in accordance with manufacture recommendations.
- Copper components exposed to city water once every 10 years
- Pressurizer relief tank internal surfaces once every 10 years

The staff also noted that the applicant appeared to be crediting visual examinations, in part, to manage cracking but did not specify that the visual techniques would be VT-1, enhanced VT-1, VT-2 or VT-3 techniques. The ASME Code, Section XI, an NRC endorsed document in 10 CFR 50.55a, indicates that only volumetric inspection techniques (such as UT or RT) are capable of detecting a crack throughout the volume of a component and that only VT-1 or enhanced VT-1 visual examination techniques or surface examination techniques (such as PT or MT) are capable of detecting surface penetrating cracks. Thus, the staff needed additional information on the inspection techniques that would be credited under this AMP to detect cracking in the components that are within the scope of the Periodic Surveillance and Preventive Maintenance Program and for which cracking is identified as an applicable aging effect requiring management.

The staff noted that, for the majority of the elastomeric or polymeric components within the scope of the AMP, the applicant credited both visual examinations and manual flexing of the components to manage changes in material properties of these elastomeric or polymeric components. The staff noted that material properties are intrinsic thermodynamic properties that cannot be monitored by direct visual or NDE inspection methods, and that changes in material properties (such as loss of fracture toughness, hardening, or increases or reductions in strength) are more appropriately managed through appropriate material property analyses (including destructive analyses) or though performance of physical tests (such as flexing, etc.) that could provide some indication of whether the material properties for the components were changing. Thus, the staff sought clarification on: (1) how a visual examination method would be capable of indicating a change in the material properties of the elastomeric or polymeric components that are within the scope of the AMP, and (2) why flexing had not been credited for managing changes in these material properties for the flexible trunks used in the circulating water system and in the elastomeric flexible connections that are located in the intake portion of the EDG duct.

To address these issues, the staff issued RAI 3.0.3.3.7-1, Part 2. In this RAI, the staff asked the applicant to clarify which aging effects are managed by the Periodic Surveillance and Preventive Maintenance Program, which parameters are indicative of these aging effects and would be monitored as part of the applicant's implementation of the program, and which inspection techniques would be used to detect the parameters that are indicative of the applicable aging effects. This was identified as Open Item 3.0.3.3.7-1, Part 2.

The applicant responded to RAI 3.0.3.3.7-1, Part 2, in a letter dated January 27, 2009. In this letter, in order to demonstrate conformance with the recommendations for "parameters monitored or inspected" program elements in SRP-LR Section A.1.2.3.3, the applicant included an aging effect monitoring table that: (1) identifies the particular aging effects that are managed by the Periodic Surveillance and Preventive Maintenance Program, (2) provides the aging mechanisms that could induce each of particular aging effects requiring management under the program, (3) provides the parameters that would be indicative of the particular aging effects that will be managed and monitored for under the AMP, and (4) provides the inspection techniques that would be used to detect the parameters that the applicant is monitoring. The table above summarizes the information provided in the applicant's aging effect monitoring table. The staff noted that in the applicant's aging effect monitoring table, it identified that the following inspection techniques would be used as condition monitoring methods for this AMP.

(1) VT-3 or equivalent visual techniques, or UT or radiographic techniques (i.e., volumetric methods), will be used to manage loss of material due to general corrosion, galvanic corrosion, MIC, or erosion. The staff finds this to be acceptable because: (1) AMSE Code Section XI, paragraph IWA-2213 lists VT-3 visual examination methods as acceptable method for detecting surface discontinuities or imperfections that may result from mechanisms such as corrosion or erosion, and (2) ASME Code, Section XI, paragraphs IWA-2231 and IWA-2232 list UT and RT methods as acceptable volumetric inspection methods that are capable of detecting any discontinuities that may occur throughout the material and thickness of a component.

(2) VT-1 or equivalent visual techniques, or UT or radiographic techniques (i.e., volumetric methods), will be used to manage loss of material by pitting corrosion or crevice corrosion. The staff finds this to be acceptable because: (1) AMSE Code Section XI, paragraph IWA-2213 list VT-1 visual examination methods as acceptable visual examination techniques for detecting surface discontinuities or imperfections cracks, wear, corrosion or erosion, and (2) ASME Code, Section XI, paragraphs IWA-2231 and IWA-2232 list UT and RT methods as acceptable volumetric inspection methods that are capable of detecting any discontinuities that may occur throughout the material and thickness of a component,

(3) VT-1 or equivalent visual techniques, or volumetric methods (e.g., UT or RT), will be used to manage cracking in metallic components. The staff finds this to be acceptable because: (1) AMSE Code Section XI, paragraph IWA-2213 lists VT-1 visual examination methods as acceptable visual examination techniques for detecting surface discontinuities or imperfections, cracks, wear, corrosion or erosion and (2) ASME Code, Section XI, paragraphs IWA-2231 and IWA-2232 list UT and RT methods as acceptable volumetric inspection methods that are capable of detecting any discontinuities that may occur throughout the material and thickness of a component,

(4) VT-3 or equivalent visual techniques, coupled with physical manipulations, will be used to manage cracking in elastomer components. The staff finds this to be acceptable because flexing of the components will capable of distorting (opening up) surfaces such that surface breaking cracks in the materials will be capable of being detected as a surface discontinuity, and because the flexible manipulations will be capable of determining whether the elastomeric materials are losing their elastic properties or are hardening or embrittling over time.

Based on this review, the staff finds that the applicant's "detection of aging effects" program element, as supplemented with information in the applicant's letter of January 27, 2009, is acceptable because the applicant has proposed valid inspection or functional testing to manage the effects of aging for the components within the scope of this AMP. Additionally, the applicant's program element meets the recommendation in SRP-LR Section A.1.2.3.4 to identify the methods that will be used to monitor the effects of aging and the parameters that are indicative of the aging effects.

The staff concludes that RAI 3.0.3.3.7-1, Part 2 is resolved and Open Item 3.0.3.3.7-1, Part 2 is closed with respect to identify the inspection methods that will be used to monitor for the effects of aging under this AMP.

(5) Monitoring and Trending - LRA Section B.1.29 states that "preventive maintenance and surveillance testing activities provide for monitoring and trending of aging degradation."

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.5.

The staff noted that the applicant's "monitoring and trending" program element discussion for the Periodic Surveillance and Preventive Maintenance Program only mentioned that the activities within the scope of the AMP provided for adequate monitoring and trending. The staff noted that the "monitoring and trending" program element for the AMP did not provide any discussion on how the data from the inspections performed under the "detection of aging effects" program element would be collected, quantified, or evaluated against applicable acceptance criteria, and used to make predictions related to degradation growth or to schedule re-inspections of the components. Thus, the staff determined that the "monitoring and trending" program element for the Periodic Surveillance and Preventive Maintenance Program would need to be amended to specify how the data from the inspections performed under the "detection of aging effects" program element would be collected, quantified, or evaluated against applicable acceptance criteria, and used to make predictions related to degradation growth or to schedule re-inspections of the components.

To address these issues, the staff issued RAI 3.0.3.3.7-1, Part 3. In this RAI, the staff asked the applicant to clarify how the inspection results and flexible manipulation data for this AMP would be collected and quantified, or evaluated against appropriate acceptance criteria, and how the trending results would be used to make predictions relative to degradation growth or to schedule re-inspections or repairs of the components that are managed by this AMP. This was identified as Open Item 3.0.3.3.7-1, Part 3.

The applicant responded to RAI 3.0.3.3.7.1-1, Part 3 in a letter dated January 27, 2009. In this response, the applicant stated that the initial periodicity of inspections and manual flexing is based on vendor recommendations, industry guidance, input from other Entergy nuclear sites, and IP specific operating experience, and that the results of these inspections and manual flexing are collected as part of the work control process. The applicant also clarified that any indications or relevant conditions of degradation are reported and submitted for evaluation under the corrective action program and that the evaluation is performed against criteria which ensure that the structure or component intended function(s) are maintained under all current licensing basis design conditions during the period of extended operation. The applicant stated that the results of these inspections and manual flexing are trended by an assigned "responsible engineer," and that, if a potential need for a change in scope or frequency of inspections is indicated based on identified patterns of degradation, a preventive maintenance change request is processed. The staff finds this to be acceptable because it is in conformance with the quality assurance requirements in the applicant’s quality assurance program for monitoring of conditions adverse to quality and for taking appropriate corrective actions for conditions that are unacceptable for further service.

Based on this response, the staff finds that the applicant’s “monitoring and trending” program element, as supplemented with the information in the applicant’s response to RAI 3.0.3.3.7-1, Part 3, is acceptable because the applicant has clarified how the inspection results and results of physical manipulation flexing tests for elastomeric components will be collected and trended consistent with the recommendations in SRP-LR Section A.1.2.3.5.

The staff confirmed that the “monitoring and trending” program element satisfies the guidance in SRP-LR Section A.1.2.3.5. The staff finds this program element acceptable. RAI 3.0.3.3.7-1, Part 3 is resolved and Open Item 3.0.3.3.7-1, Part 3 is closed.

(6) Acceptance Criteria - LRA Section B.1.29 states that the “Periodic Surveillance and Preventive Maintenance Program acceptance criteria are defined in specific inspection and testing procedures. Acceptance criteria include appropriate temperature, no significant wear, corrosion, cracking, change in material properties (for elastomers), and significant fouling based on applicable intended functions established by plant design basis.”

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.6.

The staff noted that the applicant’s “acceptance criteria” program element for the Periodic Surveillance and Preventive Maintenance Program only made a general statement as to what the acceptance criteria are and did not establish specific acceptance criteria for each of the aging effects that are applicable to the components within the scope of the AMP. The staff also noted that the applicant had indicated that the "acceptance criteria" program element would be enhanced, in part, to specific what these acceptance criteria are. The staff sought clarification as to why establishment of the acceptance criteria for this AMP could be deferred through the applicant's enhancement of the program, as stated in LRA Commitment No. 21. Therefore, in RAI 3.0.3.3.7-1, Part 4, the staff asked the applicant to define what the acceptance criteria are for each of the aging effects that are managed under the scope of the AMP. This was identified as Open Item 3.0.3.3.7-4.

The applicant responded to RAI 3.0.3.3.7.1-1, Part 4 in a letter dated January 27, 2009. In this response, the applicant stated that any indications or relevant conditions of degradation are reported and submitted for further evaluation as part of the corrective action program and that these evaluations are performed against specific acceptance criteria which ensure that the structure or component intended function(s) will be maintained under all current licensing basis design conditions during the period of extended operation. The applicant clarified that these acceptance criteria include no unacceptable wear, corrosion, cracking, change in material properties (for elastomers), or significant fouling, and that the specific quantitative or qualitative criteria (i.e., limits) on acceptability are contained in manufacturer information or vendor manuals for some individual components. The applicant clarified that an engineering review process is used to establish the acceptance criteria for those situations where appropriate manufacturer data are unavailable. The staff noted that this is consistent with the following guidance in SRP-LR Section A.1.2.3.6:

"Acceptance criteria could be specific numerical values, or could consist of a discussion of the process for calculating specific numerical values of conditional acceptance criteria to ensure that the structure and component intended function(s) will be maintained under all CLB design conditions."

Based on its review, the staff finds that the applicant "acceptance criteria" program element, as supplemented by information in the applicant's response to RAI 3.0.3.3.7-1, Part 4, is acceptable because the applicant has clarified what the acceptance criteria are for the aging effects within the scope of this AMP.

The staff concludes that RAI 3.0.3.3.7-1, Part 4 is resolved and Open Item 3.0.3.3.7-1, Part 4 is closed.

(10) Operating Experience - LRA Section B.1.29, as amended by letter dated June 30, 2009, states that typical inspection results of this program include:

- IP2 reactor building polar crane (May 2006): no indication of corrosion, cracking, or wear in the crane structural members.
- IP3 reactor building polar crane (February 2001 and March 2005): no indication of corrosion, cracking, or wear in the crane structural members.
- IP2 and IP3 recirculation pumps and related system components (2005 and 2006): no deficiencies.
- IP2 diesel generator building floor drain backwater valves (October 2006): no

loss of material.

- IP2 and IP3 EDGs (2005 and 2006): no unacceptable loss of material.
- Security generator (January 2002 and December 2005): no significant corrosion or wear.
- IP3 Appendix R diesel generator (September 2006 and December 2006): no significant corrosion or wear.

The applicant stated that “use of proven monitoring techniques and acceptance criteria assures continued program effectiveness in managing aging effects for passive components.”

SRP-LR Section A.1.2.3.10 establishes the following recommendations for discussion of operating experience for existing AMPs:

> Operating experience with existing programs should be discussed. The operating experience of aging management programs, including past corrective actions resulting in program enhancements or additional programs, should be considered. A past failure would not necessarily invalidate an aging management program because the feedback from operating experience should have resulted in appropriate program enhancements or new programs. This information can show where an existing program has succeeded and where it has failed (if at all) in intercepting aging degradation in a timely manner. This information should provide objective evidence to support the conclusion that the effects of aging will be managed adequately so that the structure and component intended function(s) will be maintained during the period of extended operation.

The staff noted that the applicant had indicated that the program was already implementing inspections on the IP2 and IP3 reactor building polar cranes, IP2 and IP3 recirculation pumps and related system components, IP2 diesel generator building floor drain backwater valves, IP2 and IP3 emergency diesel generators (EDGs), the security generator, and the IP3 Appendix R fire protection diesel generator. The staff noted that of the inspections performed, the applicant’s indicated that there were no indications of aging only for the inspections that were performed on polar cranes, and on the IP2 diesel generator building floor drain backwater valves. The staff noted that, for the aging statements on the inspections that were performed on the other components, the statements were ambiguous in that the applicant did not distinguish whether aging had been detected but that the amount of aging was determined to be acceptable when compared to the acceptance criteria for the aging effect or whether the inspections did not identify the presence of aging effects in the components being inspected. Thus, the staff needed additional information on the following aging statements that were made in the “operating experience” program element discussion for the AMP:

1. Inspection statement for the IP3 NaOH tank – requesting clarification on the statement “no deficiencies. Ultrasonic measurement of wall thickness was satisfactory” and in particular whether loss of material had been detected in the component even though the amount of loss material was found to be acceptable.

2. Inspection statement for the IP2 and IP3 recirculation pumps and related system components – requesting clarification on the statement “no deficiencies” and in particular whether this means that no aging effects had been detected, or that some specific aging (e.g., cracking, loss of material, etc.) I had been detected in the component even though the amount of aging was found to be acceptable.

3. Inspection statements for the IP2 and IP3 EDGs, the security diesel generator, and the IP3 Appendix R fire protection diesel generator – requesting clarification on the statements “no unacceptable loss of material” and “no significant corrosion or wear” and in particular whether this means that no loss of material by corrosion, erosion or wear (or other mechanisms) was detecting or that some loss of material was detected in the components even though the amount of loss of material was found to be acceptable.

The staff sought clarification on whether any aging effects had been detected in these components as a result of the past periodic surveillance and Preventive maintenance inspections that had been performed on these components, and if so, identification of what the appropriate corrective actions were for dispositioning these components in order to ensure that the program is implementing its appropriate “corrective actions” program element criteria. In RAI 3.0.3.3.7.1-1, Part 5, the staff asked the applicant to clarify the meaning of its references to no unacceptable degradation. This was identified as Open Item 3.0.3.3.7-1, Part 5.

The applicant responded to RAI 3.0.3.3.7-1, Part 5 in a letter dated January 27, 2009. A portion of this response was amended by letter dated June 30, 2009, due to a plant modification which eliminated the sodium hydroxide (liquid injection) from the containment spray system. In its response, the applicant clarified that the inspections of the IP2 and IP3 recirculation pumps, IP2 and IP3 EDGs, the security generator, and the IP3 Appendix R fire protection diesel generator found no evidence of loss of material. The staff finds that the applicant’s response to RAI 3.0.3.3.7-1, Part 5 resolves the staff’s issue with the operating experience discussion because it clarifies that the inspections of these components confirmed that there was no loss of material occurring in the components. Thus, the staff finds the applicant’s “operating experience” program element, as modified by the information in the applicant’s response to RAI 3.0.3.3.7-1, Part 5, to be acceptable because the applicant has clarified that it has been performing periodic condition monitoring of the subject components as part of the periodic inspections that are implemented as part of this AMP. The staff concludes that RAI 3.0.3.3.7-1, Part 5 is resolved and Open Item 3.0.3.3.7-1, Part 5 is closed. The staff notes that the applicant’s operating experience discussion for this AMP, as supplemented in the applicant’s response to RAI 3.0.3.3.7-1, Part 5, meets the recommendation in SRP-LR Section A.1.2.3.10 because the applicant adequately summarized the periodic inspections that the applicant had performed under this AMP over the last 5 years of plant operation and had summarized the results of the inspections, demonstrating there had not been any age-related degradation in the components that were inspected under this AMP.

Based on this review, the staff finds that the applicant’s “operating experience” program element, as supplemented by the applicant’s response to RAI 3.0.3.3.7-1, Part 5, is acceptable because it meets the recommendation in SRP-LR Section A.1.2.3.10 to discuss the relevant operating experience for the components that have been inspected through the implementation of an existing AMP.

The staff confirmed that the "operating experience" program element satisfies the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.28 and A.3.1.28, the applicant provided the UFSAR supplement for the Periodic Surveillance and Preventive Maintenance Program. The staff reviewed these sections and finds the UFSAR supplement information is an adequate summary description of the program, as required by 10 CFR 54.21(d). The staff notes that the UFSAR Supplement summary description provided an acceptable summary listing of the components and activities that are within scope of this AMP. The staff also notes that, in this UFSAR Supplement, the applicant included LRA Commitment 21, in which the applicant committed to enhance the "scope of program," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements of the AMP as follows: "Program activity guidance documents will be developed or revised as necessary to assure that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation."

Based on this review, the staff finds that the applicant has provided an acceptable UFSAR Supplement summary description for this AMP because: (1) the summary description appropriately summarizes the components and activities that are within the scope of the AMP, (2) the applicant has clearly defined what the program elements are for this AMP, and has provided its bases on why these program elements are in conformance with the recommendations of SRP-LR Section A.1.2.3, and (3) in LRA Commitment No. 21, the applicant has committed to enhance the program to develop activity documents to reflect the program elements for this AMP. The staff concludes that RAI 3.0.3.3.7-1, Parts 1, 2, 3, ,4 and 5 are resolved and Open Item 3.0.3.3.7-1, Parts 1, 2, 3, 4, and 5 are closed with respect to the acceptability of the UFSAR Supplement summary description for this AMP.

Conclusion. On the basis of its review of the applicant's Periodic Surveillance and Preventive Maintenance Program, the staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.8 Water Chemistry Control - Auxiliary Systems Program

Summary of Technical Information in the Application. LRA Section B.1.39 and Amendment 1 to the LRA, Attachment 1, describe the existing Water Chemistry Control - Auxiliary Systems Program as a plant-specific program.

The Water Chemistry Control - Auxiliary Systems Program manages loss of material and cracking for components exposed to treated water by sampling and analysis to minimize component exposure to aggressive environments for the stator cooling water systems. The One-Time Inspection Program for Water Chemistry utilizes inspections or nondestructive evaluations of representative samples to verify whether the Water Chemistry Control - Auxiliary

Systems Program has been effective in managing aging effects.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in LRA Section B.1.39 on the applicant's demonstration of the Water Chemistry Control - Auxiliary Systems Program to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

The staff reviewed the Water Chemistry Control - Auxiliary Systems Program against the AMP elements found in the GALL Report, in SRP-LR Section A.1.2.3, and in SRP-LR Table A.1-1, focusing on how the program manages aging effects through the effective incorporation of 10 elements ((1) "scope of the program," (2) "preventive actions," (3) "parameters monitored or inspected," (4) "detection of aging effects," (5) "monitoring and trending," (6) "acceptance criteria," (7) "corrective actions," (8) "confirmation process," (9) "administrative controls," and (10) "operating experience").

In Audit Item 90, the staff asked the applicant to describe past and present surveillance tests, sampling, and analysis activities for managing the effects of aging on components within the scope of this AMP. By letter dated December 18, 2007, the applicant stated that since thickness measurements are performed every five years under the Periodic Surveillance and Preventive Maintenance Program, use of the Water Chemistry Control - Auxiliary Systems Program for the NaOH tank is not required. By letter dated December 18, 2007 the applicant amended the LRA to remove the Water Chemistry Control - Auxiliary Systems Program as an aging management program for the NaOH tank. By letter dated June 30, 2009, the applicant amended the LRA due to a plant modification which eliminated the NaOH tank and piping and fittings from the containment spray system.

The applicant indicated that program elements (7) "corrective actions," (8) "confirmation process," and (9) "administrative controls" are parts of the site-controlled QA program. The staff's evaluation of the QA program is in SER Section 3.0.4. Evaluation of the remaining seven elements follows:

(1) Scope of the Program - LRA Section B.1.39, as amended, states that program activities include sampling and analysis of the stator cooling water system to minimize component exposure to aggressive environments.

    The staff reviewed the program basis document and determined that it adequately describes the specific system and components in the scope of this program for which aging will be managed. The staff reviewed the system and determined that it uses treated water as the cooling medium. Since this program manages aging by monitoring and analyzing the coolant, the stator cooling water systems are appropriate for inclusion in the scope of this program.

    The staff confirmed that the "scope of the program" program element satisfies the guidance in SRP-LR Section A.1.2.3.1. The staff finds this program element acceptable.

(2) Preventive Actions - LRA Section B.1.39 states that the program includes monitoring and control of treated water for components included in the scope of the program to minimize exposure to aggressive environments, thereby mitigating the effects of aging.

The staff determined that the program includes monitoring and control of water chemistry to minimize component exposure to aggressive water environments. The aging effects managed by this program are loss of material, fouling, and cracking, which are directly related to the purity and aggressiveness of the water to which the components are exposed. Therefore, monitoring and controlling the water chemistry is an effective means of managing loss of material for the components in the scope of this program. The staff finds these preventive actions to be appropriate to manage the aging effects for which this program is credited.

The staff confirmed that the "preventive actions" program element satisfies the guidance in SRP-LR Section A.1.2.3.2. The staff finds this program element acceptable.

(3) Parameters Monitored or Inspected - LRA Section B.1.39, as amended, states that treated water is monitored to mitigate degradation through control of impurities. Stator cooling water is monitored for copper and conductivity monthly.

The staff noted that this program is credited to manage loss of material, fouling, and cracking for components exposed to treated water. These aging effects are directly related to the purity and aggressiveness of the water, which are based on the conductivity, pH, and dissolved oxygen in the water. Therefore, monitoring these parameters is an effective means of assessing the purity and aggressiveness of the water, and determining whether corrective actions are needed to modify the water chemistry. On this basis, the staff finds these parameters acceptable for this program.

In Audit Item 91, the staff asked the applicant to describe the procedures used to perform surveillance activities and the basis for acceptance criteria and sample / test frequencies. By letter dated December 18, 2007, the applicant stated that the stator cooling water systems are high purity systems in which poor oxygen control can cause an increase in copper corrosion products. Based on this experience, stator cooling water is monitored monthly for conductivity and copper. The staff determined that the applicant's basis for selection of parameters is acceptable since it considers vendor specifications, industry standards, and operating experience.

The staff confirmed that the "parameters monitored or inspected" program element satisfies the guidance in SRP-LR Section A.1.2.3.3. The staff finds this program element acceptable.

(4) Detection of Aging Effects - LRA Section B.1.39 states that the program manages loss of material and cracking for stainless steel, carbon steel, and copper alloy components included in the scope of the program. This is a mitigation program and does not provide for detection of aging effects. However, the One-Time Inspection Program describes inspections planned to verify the effectiveness of water chemistry control programs to ensure that significant degradation has not occurred and component intended function is maintained during the period of extended operation.

The staff determined that this program includes monitoring and control of water chemistry to manage loss of material, fouling, and cracking of auxiliary system components. These aging effects are directly related to the purity and aggressiveness of the water; therefore, monitoring these parameters will provide an effective means of mitigating aging. The monitoring frequencies will provide for timely detection of adverse water chemistry such that corrective actions can be taken prior to a loss of component intended function. The staff finds these activities appropriate for managing the aging effects for which this program is credited since they will provide reasonable assurance that the component intended function will be maintained for the extended period of operation.

The staff confirmed that the "detection of aging effects" program element satisfies the guidance in SRP-LR Section A.1.2.3.4. The staff finds this program element acceptable.

(5) Monitoring and Trending - LRA Section B.1.39 states that initially, analytical results are interpreted by the chemist performing the analysis. Abnormal trends in the chemistry data are evaluated by that person given the status of that system at that time. Any significant abnormality or trend, as well as out of specification or out of control band chemistry parameter is brought to the attention of the Shift Manager and Chemistry Management. Values from analyses are archived for long-term trending and review. Trending is not required to predict the extent of degradation since maintaining parameters within acceptance criteria prevents degradation. Operating experience indicates effectiveness in preventing aging effects if parameters are maintained within limits.

The staff reviewed the applicant's program implementing procedures and determined that appropriate administrative controls and program activities are in place to monitor and trend chemistry parameters to identify aging effects and take corrective actions prior to the loss of a component intended function. The staff finds that the applicant's use of site chemistry staff reviews and quarterly group data review sessions is an effective means of monitoring water chemistry parameters.

The staff confirmed that the "monitoring and trending" program element satisfies the guidance in SRP-LR Section A.1.2.3.5. The staff finds this program element acceptable.

(6) Acceptance Criteria - LRA Section B.1.39, as amended, states the following acceptance criteria for stator cooling water systems:

Parameter	**Acceptance Criteria**
Conductivity	< 0.5 µmhos/cm
Copper	< 20 ppb

The staff confirmed that the "acceptance criteria" program element satisfies the guidance in SRP-LR Section A.1.2.3.6. The staff finds this program element acceptable.

(10) Operating Experience - LRA Section B.1.39 states that the QA audits of the chemistry control program in 2005 and 2006 found compliance with all guidelines (INPO 03-004, EPRI TR-105714, and TR-102134) for chemistry performance satisfactory with sufficient parameters measured to detect abnormal conditions or condition changes. The audits found all chemistry parameters maintained within specified bands and auxiliary systems treated and controlled to industry guidelines. Adherence to chemistry specifications assures continued program effectiveness in managing the effects of aging.

In Audit Item 90, the staff asked the applicant about past and present surveillance tests, sampling and analysis activities for managing the effects of aging on components within the scope of this AMP. By letter dated December 18, 2007, the applicant stated that recent monthly tests of stator cooling water samples have been within the specification. The applicant further stated that monthly stator cooling water analysis will continue per the requirements of the applicant's procedure.

The staff reviewed the operating experience provided in the LRA, and the applicant's operating experience review results report, and determined that there were no aging effects identified that are not bounded by industry operating experience. Recent operating experience indicated that all chemistry parameters have been maintained within specified bands and auxiliary systems treated and controlled to industry guidelines. This operating experience provides objective evidence that this program is effective in detecting and managing aging effects in the auxiliary cooling water systems.

The staff confirmed that the "operating experience" program element satisfies the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.38 and A.3.1.38, the applicant provided the UFSAR supplement for the Water Chemistry Control - Auxiliary Systems Program. In Amendment 1, dated December 18, 2007, the applicant revised the second paragraphs of Sections A.2.1.38 and A.3.1.38 as follows:

"Program activities include sampling and analysis to minimize component exposure to aggressive environments for stator cooling water systems."

The staff reviewed these sections and finds the UFSAR supplement information is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Water Chemistry Control - Auxiliary Systems Program, the staff concludes that the applicant has demonstrated that effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.4 QA Program Attributes Integral to Aging Management Programs

3.0.4.1 Summary of Technical Information in the Application

In Sections A.2.1, "Aging Management Program and Activities," and B.0.3, "Corrective Actions, Confirmation Process and Administrative Controls," of the LRA, the applicant described the elements of corrective action, confirmation process, and administrative controls that are applied to the AMPs for both safety-related and nonsafety-related components. The Entergy Quality Assurance Program (EQAP) is used which includes the elements of corrective action, confirmation process, and administrative controls. Corrective actions, confirmation, and administrative controls are applied in accordance with the EQAP regardless of the safety classification of the components. LRA Sections A.2.1 and B.0.3, stated that the EQAP implements the requirements of 10 CFR 50, Appendix B, and is consistent with the GALL Report.

3.0.4.2 *Staff Evaluation*

Pursuant to 10 CFR 54.21(a)(3), the 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, BTP RLSB-1, "Aging Management Review – Generic," describes ten elements of an acceptable AMP. Elements (7), (8), and (9) are associated with the QA activities of "corrective actions," "confirmation process," and "administrative controls." BTP RLSB-1 Table A.1-1, "Elements of an Aging Management Program for License Renewal," provides the following description of these program elements:

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

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

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

SRP-LR BTP IQMB-1, "Quality Assurance for Aging Management Programs," notes that AMP aspects that affect the quality of safety-related SSCs are subject to the QA requirements of 10 CFR Part 50 Appendix B. Additionally, for nonsafety-related SCs subject to an AMR, the applicant may use the existing 10 CFR Part 50 Appendix B QA program to address the elements of "corrective actions," "confirmation process," and "administrative controls." BTP IQMB-1 provides the following guidance on the QA attributes of AMPs:

1. Safety-related structures and components are subject to 10 CFR Part 50 Appendix B requirements, which are adequate to address all quality-related aspects of an aging management program consistent with the CLB of the facility for the period of extended operation.
2. For nonsafety-related structures and components that are subject to an AMR for license renewal, an applicant has an option to expand the scope of its 10 CFR Part 50 Appendix B program to include these structures and components to address corrective actions, the confirmation process, and administrative controls for aging management during the period of extended operation. The reviewer should verify that the applicant has documented such a commitment in the FSAR supplement in accordance with 10 CFR 54.21(d).

The NRC staff reviewed the applicant's aging management programs (AMPs) described in Appendix A, "Updated Final Safety Analysis Report Supplement," and Appendix B, "Aging Management Programs and Activities," of the LRA, and the associated implementing documents. The purpose of this review was to ensure that the quality assurance attributes (corrective action, confirmation process, and administrative controls) are consistent with the staff's guidance described in SRP-LR BTP RLSB-1 and BTP IQMPB-1. In addition, the staff reviewed the enhancements for the "corrective actions" program element as specified in LRA Sections B.1.16 and B.1.26, and determined that the enhancements did not affect the applicant's application of the EQAP. Based on the NRC staff's evaluation, the descriptions of the AMPs and their associated quality attributes provided in Appendix A, Section A.2.1, and

Appendix B, Section B.0.3, of the LRA were determined to be consistent with the staff's position regarding quality assurance for aging management.

3.0.4.3 *Conclusion*

On the basis of the NRC staff's evaluation, the descriptions and applicability of the plant-specific AMPs and their associated quality attributes provided in Appendix A, Section A.2.1, and Appendix B, Section B.0.3 of the LRA, the quality assurance elements "corrective actions," "confirmation process," and "administrative controls," as applied to the applicant's programs were determined to be consistent with the staff's position regarding QA for aging management. The staff concludes that the QA attributes "corrective action," "confirmation process," and "administrative control," of the applicant's programs are consistent with 10 CFR 54.21(a)(3).

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, internals, and reactor coolant system components and component groups of:

- reactor vessel
- reactor vessel internals
- reactor coolant system and pressurizer
- steam generator

3.1.1 Summary of Technical Information in the Application

LRA Section 3.1 provides AMR results for the reactor vessel, reactor vessel internals, and reactor coolant system components and component groups. LRA Table 3.1.1, "Summary of Aging Management Programs for the Reactor Coolant System Evaluated in Chapter IV of NUREG-1801," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the reactor vessel, reactor vessel internals, and reactor coolant system components and component groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.1.2 Staff Evaluation

The staff reviewed LRA Section 3.1 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for the reactor vessel, reactor vessel internals, and reactor coolant system components within the scope of license renewal and subject to an AMR, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff conducted an onsite audit of AMRs to ensure the applicant's claim that certain AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's audit evaluation are documented in SER Section 3.1.2.1.

In the onsite audit, the staff also selected AMRs consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the SRP-LR Section 3.1.2.2 acceptance criteria. The staff's audit evaluations are documented in SER Section 3.1.2.2.

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 3.1.2.3.

For components which the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR line items and the plant's operating experience to verify the applicant's claims.

Table 3.1-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.1 and addressed in the GALL Report.

Table 3.1-1 Staff Evaluation for Reactor Vessel, Reactor Vessel Internals and Reactor Coolant System Components in the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel pressure vessel support skirt and attachment welds (3.1.1-1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	See SER Section 3.1.2.2.1
Steel; stainless steel; steel with nickel alloy or stainless steel cladding; nickel alloy reactor vessel components: flanges; nozzles; penetrations; safe ends; thermal sleeves; vessel shells, heads and welds (3.1.1-2)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects are to be addressed for Class 1 components	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel; stainless steel; steel with nickel alloy or stainless steel cladding; nickel alloy reactor coolant pressure boundary piping, piping components, and piping elements exposed to reactor coolant (3.1.1-3)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects are to be addressed for Class 1 components	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.1)
Steel pump and valve closure bolting (3.1.1-4)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) check Code limits for allowable cycles (less than 7000 cycles) of thermal stress range	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.1)
Stainless steel and nickel alloy reactor vessel internals components (3.1.1-5)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Consistent with GALL Report (see SER Section 3.1.2.2.1)
Nickel Alloy tubes and sleeves in a reactor coolant and secondary feedwater/steam environment (3.1.1-6)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Consistent with GALL Report (see SER Section 3.1.2.2.1)
Steel and stainless steel reactor coolant pressure boundary closure bolting, head closure studs, support skirts and attachment welds, pressurizer relief tank components, SG components, piping and components external surfaces and bolting (3.1.1-7)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Consistent with GALL Report (see SER Section 3.1.2.2.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel; stainless steel; and nickel alloy reactor coolant pressure boundary piping, piping components, piping elements; flanges; nozzles and safe ends; pressurizer vessel shell heads and welds; heater sheaths and sleeves; penetrations; and thermal sleeves (3.1.1-8)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects are to be addressed for Class 1 components	Yes	TLAA	Consistent with GALL Report (see SER Section 3.1.2.2.1)
Steel; stainless steel; steel with nickel alloy or stainless steel cladding; nickel alloy reactor vessel components: flanges; nozzles; penetrations; pressure housings; safe ends; thermal sleeves; vessel shells, heads and welds (3.1.1-9)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects are to be addressed for Class 1 components	Yes	TLAA	Consistent with GALL Report (see SER Section 3.1.2.2.1)
Steel; stainless steel; steel with nickel alloy or stainless steel cladding; nickel alloy steam generator components (flanges; penetrations; nozzles; safe ends, lower heads and welds) (3.1.1-10)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects are to be addressed for Class 1 components	Yes	TLAA	Consistent with GALL Report (see SER Section 3.1.2.2.1)
Steel top head enclosure (without cladding) top head nozzles (vent, top head spray or RCIC, and spare) exposed to reactor coolant (3.1.1-11)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.2)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel steam generator shell assembly exposed to secondary feedwater and steam (3.1.1-12)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry Control - Primary and Secondary One-Time Inspection	Consistent with GALL Report (see SER Section 3.1.2.2.2(1))
Steel and stainless steel isolation condenser components exposed to reactor coolant (3.1.1-13)	Loss of material due to general (steel only), pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.2(2))
Stainless steel, nickel alloy, and steel with nickel alloy or stainless steel cladding reactor vessel flanges, nozzles, penetrations, safe ends, vessel shells, heads and welds (3.1.1-14)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.2(3))
Stainless steel; steel with nickel alloy or stainless steel cladding; and nickel alloy reactor coolant pressure boundary components exposed to reactor coolant (3.1.1-15)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.2(3))
Steel steam generator upper and lower shell and transition cone exposed to secondary feedwater and steam (3.1.1-16)	Loss of material due to general, pitting, and crevice corrosion	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry and, for Westinghouse Model 44 and 51 S/G, if general and pitting corrosion of the shell is known to exist, additional inspection procedures are to be developed.	Yes	Inservice Inspection and Water Chemistry Control - Primary and Secondary	Consistent with GALL Report (see SER Section 3.1.2.2.2(4))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel (with or without stainless steel cladding) reactor vessel beltline shell, nozzles, and welds (3.1.1-17)	Loss of fracture toughness due to neutron irradiation embrittlement	TLAA, evaluated in accordance with 10 CFR 50, Appendix G, and RG 1.99. The applicant may choose to demonstrate that the materials of the nozzles are not controlling for the TLAA evaluations.	Yes	TLAA	Consistent with GALL Report (see SER Section 3.1.2.2.3(1))
Steel (with or without stainless steel cladding) reactor vessel beltline shell, nozzles, and welds; safety injection nozzles (3.1.1-18)	Loss of fracture toughness due to neutron irradiation embrittlement	Reactor Vessel Surveillance	Yes	Reactor Vessel Surveillance	Consistent with GALL Report (see SER Section 3.1.2.2.3(2))
Stainless steel and nickel alloy top head enclosure vessel flange leak detection line (3.1.1-19)	Cracking due to stress corrosion cracking (SCC) and intergranular stress corrosion cracking (IGSCC)	A plant-specific aging management program is to be evaluated.	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.4(1))
Stainless steel isolation condenser components exposed to reactor coolant (3.1.1-20)	Cracking due to SCC and IGSCC	Inservice Inspection (IWB, IWC, and IWD), Water Chemistry, and plant-specific verification program	Yes	Not applicable	Not applicable to 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 (3.1.1-21)	Crack growth due to cyclic loading	TLAA	Yes	Not applicable	Not applicable (see SER Section 3.1.2.2.5)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel alloy reactor vessel internals components exposed to reactor coolant and neutron flux (3.1.1-22)	Loss of fracture toughness due to neutron irradiation embrittlement, void swelling	FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.	No, but licensee commitment needs to be confirmed	Committed to Reactor Vessel Internals Inspection plan being developed by the industry	Consistent with GALL Report (see SER Section 3.1.2.2.6)
Stainless steel reactor vessel closure head flange leak detection line and bottom-mounted instrument guide tubes (3.1.1-23)	Cracking due to SCC	A plant-specific aging management program is to be evaluated.	Yes	Inservice Inspection and Water Chemistry Control - Primary and Secondary	Consistent with GALL Report (see SER Section 3.1.2.2.7(1))
Class 1 cast austenitic stainless steel piping, piping components, and piping elements exposed to reactor coolant (3.1.1-24)	Cracking due to SCC	Water Chemistry and, for CASS components that do not meet the NUREG-0313 guidelines, a plant-specific AMP	Yes	Water Chemistry Control - Primary and Secondary and Thermal Embrittlement of Cast Austenitic Stainless Steel (CASS) supplemented by the Inservice Inspection Program	Consistent with GALL Report (see SER Section 3.1.2.2.7(2))
Stainless steel jet pump sensing line (3.1.1-25)	Cracking due to cyclic loading	A plant-specific aging management program is to be evaluated.	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.8(1))
Steel and stainless steel isolation condenser components exposed to reactor coolant (3.1.1-26)	Cracking due to cyclic loading	Inservice Inspection (IWB, IWC, and IWD) and plant-specific verification program	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.8(2))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel alloy reactor vessel internals screws, bolts, tie rods, and hold-down springs (3.1.1-27)	Loss of preload due to stress relaxation	FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.	No, but licensee commitment needs to be confirmed	Committed to Reactor Vessel Internals Inspection plan being developed by the industry	Consistent with GALL Report (see SER Section 3.1.2.2.9)
Steel steam generator feedwater impingement plate and support exposed to secondary feedwater (3.1.1-28)	Loss of material due to erosion	A plant-specific aging management program is to be evaluated.	Yes	None	Not applicable (see SER Section 3.1.2.2.10)
Stainless steel steam dryers exposed to reactor coolant (3.1.1-29)	Cracking due to flow-induced vibration	A plant-specific aging management program is to be evaluated.	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.11)
Stainless steel reactor vessel internals components (e.g., Upper internals assembly, RCCA guide tube assemblies, Baffle/former assembly, Lower internal assembly, shroud assemblies, Plenum cover and plenum cylinder, Upper grid assembly, Control rod guide tube (CRGT) assembly, Core support shield assembly, Core barrel assembly, Lower grid assembly, Flow distributor assembly, Thermal shield, Instrumentation support structures) (3.1.1-30)	Cracking due to SCC, irradiation-assisted SCC	Water Chemistry and FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval less than 24 months before the extended period an RVI inspection plan based on industry recommendation.	No, but licensee commitment needs to be confirmed	Water Chemistry Control – Primary and Secondary Committed to Reactor Vessel Internals Inspection plan being developed by the industry	Consistent with GALL Report (see SER Section 3.1.2.2.12)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Nickel alloy and steel with nickel alloy cladding piping, piping component, piping elements, penetrations, nozzles, safe ends, and welds (other than reactor vessel head); pressurizer heater sheaths, sleeves, diaphragm plate, manways and flanges; core support pads/core guide lugs (3.1.1-31)	Cracking due to primary water stress corrosion cracking (PWSCC)	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry and FSAR supplement commitment to implement applicable plant commitments to (1) NRC Orders, Bulletins, and Generic Letters associated with nickel alloys and (2) staff-accepted industry guidelines.	No, but licensee commitment needs to be confirmed	Inservice Inspection, Water Chemistry Control - Primary and Secondary, and Nickel Alloy Inspection Programs (with commitment)	Consistent with GALL Report (see SER Section 3.1.2.2.13)
Steel steam generator feedwater inlet ring and supports (3.1.1-32)	Wall thinning due to flow-accelerated corrosion	A plant-specific aging management program is to be evaluated.	Yes	Steam Generator Integrity	Consistent with GALL Report (see SER Section 3.1.2.2.14)
Stainless steel and nickel alloy reactor vessel internals components (3.1.1-33)	Changes in dimensions due to void swelling	FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval less than 24 months before the extended period an RVI inspection plan based on industry recommendation.	No, but licensee commitment needs to be confirmed	Committed to Reactor Vessel Internals Inspection plan being developed by the industry	Consistent with GALL Report (see SER Section 3.1.2.2.15)
Stainless steel and nickel alloy reactor control rod drive head penetration pressure housings (3.1.1-34)	Cracking due to SCC and PWSCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry and for nickel alloy, comply with applicable NRC Orders and provide a commitment in the FSAR supplement to implement applicable (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines.	No, but licensee commitment needs to be confirmed	Inservice Inspection, Water Chemistry Control - Primary and Secondary, and Reactor Vessel Head Penetration Inspection (with commitment)	Consistent with GALL Report (see SER Section 3.1.2.2.16(1))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel with stainless steel or nickel alloy cladding primary side components; steam generator upper and lower heads, tubesheets and tube-to-tube sheet welds (3.1.1-35)	Cracking due to SCC and PWSCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry and for nickel alloy, comply with applicable NRC Orders and provide a commitment in the FSAR supplement to implement applicable (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines.	No, but licensee commitment needs to be confirmed	Inservice Inspection and Water Chemistry Control – Primary and Secondary for carbon steel with stainless steel clad. Water Chemistry Control – Primary and Secondary and Steam Generator Integrity for carbon steel with Nickel alloy clad (with commitment).	Consistent with GALL Report (see SER Section 3.1.2.2.16(1))
Nickel alloy, stainless steel pressurizer spray head (3.1.1-36)	Cracking due to SCC and PWSCC	Water Chemistry and One-Time Inspection and, for nickel alloy welded spray heads, comply with applicable NRC Orders and provide a commitment in the FSAR supplement to implement applicable (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines.	No, but licensee commitment needs to be confirmed	Not used	Not applicable (see SER Section 3.1.2.2.16(2))
Stainless steel and nickel alloy reactor vessel internals components (e.g., Upper internals assembly, RCCA guide tube assemblies, Lower internal assembly, CEA shroud assemblies, Core shroud assembly, Core support shield assembly, Core barrel assembly, Lower grid assembly, Flow distributor assembly) (3.1.1-37)	Cracking due to SCC, PWSCC, irradiation-assisted SCC	Water Chemistry and FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.	No, but licensee commitment needs to be confirmed	Water Chemistry Control – Primary and Secondary and committed to Reactor Vessel Internals Inspection plan being developed by the industry	Consistent with GALL Report (see SER Section 3.1.2.2.17)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel (with or without stainless steel cladding) control rod drive return line nozzles exposed to reactor coolant (3.1.1-38)	Cracking due to cyclic loading	BWR Control Rod Drive Return Line Nozzle	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Steel (with or without stainless steel cladding) feedwater nozzles exposed to reactor coolant (3.1.1-39)	Cracking due to cyclic loading	BWR Feedwater Nozzle	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel and nickel alloy penetrations for control rod drive stub tubes instrumentation, jet pump instrumentation, standby liquid control, flux monitor, and drain line exposed to reactor coolant (3.1.1-40)	Cracking due to SCC, IGSCC, cyclic loading	BWR Penetrations and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel and nickel alloy piping, piping components, and piping elements greater than or equal to 4 NPS; nozzle safe ends and associated welds (3.1.1-41)	Cracking due to SCC and IGSCC	BWR Stress Corrosion Cracking and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel and nickel alloy vessel shell attachment welds exposed to reactor coolant (3.1.1-42)	Cracking due to SCC and IGSCC	BWR Vessel ID Attachment Welds and Water Chemistry	No	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 (3.1.1-43)	Cracking due to SCC and IGSCC	BWR Vessel Internals and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel alloy core shroud, core plate, core plate bolts, support structure, top guide, core spray lines, spargers, jet pump assemblies, control rod drive housing, nuclear instrumentation guide tubes (3.1.1-44)	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Steel piping, piping components, and piping elements exposed to reactor coolant (3.1.1-45)	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Nickel alloy core shroud and core plate access hole cover (mechanical covers) (3.1.1-46)	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel and nickel alloy reactor vessel internals exposed to reactor coolant (3.1.1-47)	Loss of material due to pitting and crevice corrosion	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Steel and stainless steel Class 1 piping, fittings and branch connections less than NPS 4 exposed to reactor coolant (3.1.1-48)	Cracking due to SCC, IGSCC (for stainless steel only), and thermal and mechanical loading	Inservice Inspection (IWB, IWC, and IWD), Water Chemistry, and One-Time Inspection of ASME Code Class 1 Small-Bore Piping	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Nickel alloy core shroud and core plate access hole cover (welded covers) (3.1.1-49)	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Inservice Inspection (IWB, IWC, and IWD), Water Chemistry, and, for BWRs with a crevice in the access hole covers, augmented inspection using UT or other demonstrated acceptable inspection of the access hole cover welds	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
High-strength low alloy steel top head closure studs and nuts exposed to air with reactor coolant leakage (3.1.1-50)	Cracking due to SCC and IGSCC	Reactor Head Closure Studs	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Cast austenitic stainless steel jet pump assembly castings; orificed fuel support (3.1.1-51)	Loss of fracture toughness due to thermal aging and neutron irradiation embrittlement	Thermal Aging and Neutron Irradiation Embrittlement of CASS	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Steel and stainless steel reactor coolant pressure boundary (RCPB) pump and valve closure bolting, manway and holding bolting, flange bolting, and closure bolting in high-pressure and high-temperature systems (3.1.1-52)	Cracking due to SCC, loss of material due to wear, loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	No	Bolting Integrity	Consistent with GALL Report (see SER Section 3.1.2.1.2)
Steel piping, piping components, and piping elements exposed to closed cycle cooling water (3.1.1-53)	Loss of material due to general, pitting, and crevice corrosion	Closed-Cycle Cooling Water System	No	Water Chemistry Control – Closed Cooling Water	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper alloy piping, piping components, and piping elements exposed to closed cycle cooling water (3.1.1-54)	Loss of material due to pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable (see SER Section 3.1.2.1.1)
Cast austenitic stainless steel Class 1 pump casings, and valve bodies and bonnets exposed to reactor coolant greater than 250°C (less than 482°F) (3.1.1-55)	Loss of fracture toughness due to thermal aging embrittlement	Inservice Inspection (IWB, IWC, and IWD). Thermal aging susceptibility screening is not necessary, inservice inspection requirements are sufficient for managing these aging effects. ASME Code Case N-481 also provides an alternative for pump casings.	No	Inservice Inspection	Consistent with GALL Report
Copper alloy greater than 15% Zn piping, piping components, and piping elements exposed to closed cycle cooling water (3.1.1-56)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Not applicable	Not applicable (see SER Section 3.1.2.1.1)
Cast austenitic stainless steel Class 1 piping, piping component, and piping elements and control rod drive pressure housings exposed to reactor coolant greater than 250°C (less than 482°F) (3.1.1-57)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS	No	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	Consistent with GALL Report
Steel reactor coolant pressure boundary external surfaces exposed to air with borated water leakage (3.1.1-58)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	No	Boric Acid Corrosion Prevention	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel steam generator steam nozzle and safe end, feedwater nozzle and safe end, AFW nozzles and safe ends exposed to secondary feedwater/steam (3.1.1-59)	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	No	Flow-Accelerated Corrosion	Consistent with GALL Report (see SER Section 3.1.2.1.5)
Stainless steel flux thimble tubes (with or without chrome plating) (3.1.1-60)	Loss of material due to wear	Flux Thimble Tube Inspection	No	Flux Thimble Tube Inspection	Consistent with GALL Report
Stainless steel, steel pressurizer integral support exposed to air with metal temperature up to 288°C (550°F) (3.1.1-61)	Cracking due to cyclic loading	Inservice Inspection (IWB, IWC, and IWD)	No	Inservice Inspection	Consistent with GALL Report
Stainless steel, steel with stainless steel cladding reactor coolant system cold leg, hot leg, surge line, and spray line piping and fittings exposed to reactor coolant (3.1.1-62)	Cracking due to cyclic loading	Inservice Inspection (IWB, IWC, and IWD)	No	Inservice Inspection	Consistent with GALL Report (see SER Section 3.1.2.1.3)
Steel reactor vessel flange, stainless steel and nickel alloy reactor vessel internals exposed to reactor coolant (e.g., upper and lower internals assembly, CEA shroud assembly, core support barrel, upper grid assembly, core support shield assembly, lower grid assembly) (3.1.1-63)	Loss of material due to wear	Inservice Inspection (IWB, IWC, and IWD)	No	Inservice Inspection	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and steel with stainless steel or nickel alloy cladding pressurizer components (3.1.1-64)	Cracking due to SCC, PWSCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry	No	Inservice Inspection and Water Chemistry Control – Primary and Secondary (for steel with stainless steel or nickel alloy clad)	Consistent with GALL Report (see SER Section 3.1.2.1.3)
Nickel alloy reactor vessel upper head and control rod drive penetration nozzles, instrument tubes, head vent pipe (top head), and welds (3.1.1-65)	Cracking due to PWSCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry and Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors	No	Inservice Inspection, Water Chemistry Control – Primary and Secondary, and Nickel Alloy Inspection	Consistent with GALL Report (see SER Section 3.1.2.1.3)
Steel steam generator secondary manways and handholds (cover only) exposed to air with leaking secondary-side water and/or steam (3.1.1-66)	Loss of material due to erosion	Inservice Inspection (IWB, IWC, and IWD) for Class 2 components	No	Not used	See SER Section 3.1.2.1.6
Steel with stainless steel or nickel alloy cladding; or stainless steel pressurizer components exposed to reactor coolant (3.1.1-67)	Cracking due to cyclic loading	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry	No	Inservice Inspection and Water Chemistry Control – Primary and Secondary	Consistent with GALL Report (see SER Section 3.1.2.1.3)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, steel with stainless steel cladding Class 1 piping, fittings, pump casings, valve bodies, nozzles, safe ends, manways, flanges, CRD housing; pressurizer heater sheaths, sleeves, diaphragm plate; pressurizer relief tank components, reactor coolant system cold leg, hot leg, surge line, and spray line piping and fittings (3.1.1-68)	Cracking due to SCC	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry	No	Inservice Inspection, Water Chemistry Control – Primary and Secondary, and One Time Inspection (for non-ISI components)	Consistent with GALL Report (see SER Section 3.1.2.1.3)
Stainless steel, nickel alloy safety injection nozzles, safe ends, and associated welds and buttering exposed to reactor coolant (3.1.1-69)	Cracking due to SCC, PWSCC	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry	No	Inservice Inspection and Water Chemistry Control – Primary and Secondary (for SS components only)	Consistent with GALL Report (see SER Section 3.1.2.1.3)
Stainless steel; steel with stainless steel cladding Class 1 piping, fittings and branch connections less than NPS 4 exposed to reactor coolant (3.1.1-70)	Cracking due to SCC, thermal and mechanical loading	Inservice Inspection (IWB, IWC, and IWD), Water chemistry, and One-Time Inspection of ASME Code Class 1 Small-bore Piping	No	Inservice Inspection, Water Chemistry Control – Primary and Secondary and One Time Inspection (small bore piping)	Consistent with GALL Report
High-strength low alloy steel closure head stud assembly exposed to air with reactor coolant leakage (3.1.1-71)	Cracking due to SCC; loss of material due to wear	Reactor Head Closure Studs	No	Reactor Head Closure Studs	Consistent with GALL Report
Nickel alloy steam generator tubes and sleeves exposed to secondary feedwater/steam (3.1.1-72)	Cracking due to OD SCC and intergranular attack, loss of material due to fretting and wear	Steam Generator Tube Integrity and Water Chemistry	No	Steam Generator Integrity and Water Chemistry Control – Primary and Secondary	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Nickel alloy steam generator tubes, repair sleeves, and tube plugs exposed to reactor coolant (3.1.1-73)	Cracking due to PWSCC	Steam Generator Tube Integrity and Water Chemistry	No	Steam Generator Integrity and Water Chemistry Control – Primary and Secondary	Consistent with GALL Report
Chrome plated steel, stainless steel, nickel alloy steam generator anti-vibration bars exposed to secondary feedwater/steam (3.1.1-74)	Cracking due to SCC, loss of material due to crevice corrosion and fretting	Steam Generator Tube Integrity and Water Chemistry	No	Steam Generator Integrity, Water Chemistry Control – Primary and Secondary and One Time Inspection	Consistent with GALL Report (see SER Sections 3.1.2.1.4, 3.1.2.1.7, and 3.1.2.1.8)
Nickel alloy once-through steam generator tubes exposed to secondary feedwater/steam (3.1.1-75)	Denting due to corrosion of carbon steel tube support plate	Steam Generator Tube Integrity and Water Chemistry	No	Not applicable	Not applicable (see SER Section 3.1.2.1.1)
Steel steam generator tube support plate, tube bundle wrapper exposed to secondary feedwater/steam (3.1.1-76)	Loss of material due to erosion, general, pitting, and crevice corrosion, ligament cracking due to corrosion	Steam Generator Tube Integrity and Water Chemistry	No	Steam Generator Integrity and Water Chemistry Control – Primary and Secondary	Consistent with GALL Report
Nickel alloy steam generator tubes and sleeves exposed to phosphate chemistry in secondary feedwater/steam (3.1.1-77)	Loss of material due to wastage and pitting corrosion	Steam Generator Tube Integrity and Water Chemistry	No	Not applicable	Not applicable (see SER Section 3.1.2.1.1)
Steel steam generator tube support lattice bars exposed to secondary feedwater/steam (3.1.1-78)	Wall thinning due to flow-accelerated corrosion	Steam Generator Tube Integrity and Water Chemistry	No	Not applicable	Not applicable (see SER Section 3.1.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Nickel alloy steam generator tubes exposed to secondary feedwater/steam (3.1.1-79)	Denting due to corrosion of steel tube support plate	Steam Generator Tube Integrity; Water Chemistry and, for plants that could experience denting at the upper support plates, evaluate potential for rapidly propagating cracks and then develop and take corrective actions consistent with NRC Bulletin 88-02.	No	Not applicable	Not applicable (see SER Section 3.1.2.1.1)
Cast austenitic stainless steel reactor vessel internals (e.g., upper internals assembly, lower internal assembly, CEA shroud assemblies, control rod guide tube assembly, core support shield assembly, lower grid assembly) (3.1.1-80)	Loss of fracture toughness due to thermal aging and neutron irradiation embrittlement	Thermal Aging and Neutron Irradiation Embrittlement of CASS	No	Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)	Consistent with GALL Report
Nickel alloy or nickel alloy clad steam generator divider plate exposed to reactor coolant (3.1.1-81)	Cracking due to PWSCC	Water Chemistry	No	Water Chemistry Control – Primary and Secondary	Consistent with GALL Report
Stainless steel steam generator primary side divider plate exposed to reactor coolant (3.1.1-82)	Cracking due to SCC	Water Chemistry	No	Not applicable	Not applicable (see SER Section 3.1.2.1.1)
Stainless steel; steel with nickel alloy or stainless steel cladding; and nickel alloy reactor vessel internals and reactor coolant pressure boundary components exposed to reactor coolant (3.1.1-83)	Loss of material due to pitting and crevice corrosion	Water Chemistry	No	Water Chemistry Control – Primary and Secondary and Steam Generator Integrity (SG tubes)	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Nickel alloy steam generator components such as, secondary side nozzles (vent, drain, and instrumentation) exposed to secondary feedwater/steam (3.1.1-84)	Cracking due to SCC	Water Chemistry and One-Time Inspection or Inservice Inspection (IWB, IWC, and IWD).	No	Not applicable to IP2 Water Chemistry Control – Primary and Secondary and One-Time Inspection, and Steam Generator Integrity for IP3	Not applicable to IP2 (see SER Section 3.1.2.1.1) Consistent with GALL Report for IP3
Nickel alloy piping, piping components, and piping elements exposed to air - indoor uncontrolled (external) (3.1.1-85)	None	None	NA	None	Consistent with GALL Report
Stainless steel piping, piping components, and piping elements exposed to air - indoor uncontrolled (External); air with borated water leakage; concrete; gas (3.1.1-86)	None	None	NA	None	Consistent with GALL Report
Steel piping, piping components, and piping elements in concrete (3.1.1-87)	None	None	NA	Not applicable	Not applicable (see SER Section 3.1.2.1.1)

The staff's review of the reactor vessel, reactor vessel internals, and reactor coolant system component groups followed any one of several approaches. In one approach, documented in SER Section 3.1.2.1, the staff reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. In the second approach, documented in SER Section 3.1.2.2, the staff reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. In the third approach, documented in SER Section 3.1.2.3, the staff 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 reactor vessel, reactor vessel internals, and reactor coolant system components is documented in SER Section 3.0.3.

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, reactor vessel internals, and reactor coolant system components:

- Bolting Integrity Program
- Boric Acid Corrosion Prevention Program
- External Surfaces Monitoring Program
- Flux Thimble Tube Inspection Program
- Inservice Inspection Program
- Nickel Alloy Inspection Program
- One-Time Inspection - Small Bore Piping Program
- Reactor Head Closure Studs Program
- Reactor Vessel Head Penetration Inspection Program
- Reactor Vessel Surveillance Program
- Steam Generator Integrity Program
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program
- Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program
- Water Chemistry Control - Closed Cooling Water Program
- Water Chemistry Control - Primary and Secondary Program

LRA Tables 3.1.2-1-IP2 through 3.1.2-4-IP2 and 3.1.2-1-IP3 through 3.1.2-4-IP3 summarize the results of AMRs for the reactor vessel, reactor vessel internals, and reactor coolant system components and indicate AMRs claimed to be consistent with the GALL Report.

For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the report, where the report 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.

For each AMR line item, the applicant stated how the information in the tables aligns with the information in the GALL Report. Notes A through E indicate how the AMR is consistent with the GALL Report. The staff audited these AMRs.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report and validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the

GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report and verified that the identified exceptions to the GALL Report AMPs have been reviewed and accepted. The staff also determined whether the applicant's AMP was consistent with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the 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 line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review and whether the identified exceptions to the GALL Report AMPs have been reviewed and accepted. The staff also determined whether the applicant's AMP was consistent with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but credits a different AMP. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the credited AMP would manage the aging effect consistently with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

The staff audited and reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs.

The staff reviewed the LRA to confirm that the applicant: (a) provided a brief description of the system, components, materials, and environments; (b) stated that the applicable aging effects were reviewed and evaluated in the GALL Report; and (c) identified those aging effects for the reactor vessel, reactor vessel internals, and reactor coolant system components that are subject to an AMR.

In response to RAI B.1.15-1, by letter dated January 4, 2008, the applicant revised the LRA to include an AMR line item for carbon steel blowdown pipe connection (nozzle) with an internal environment of treated water, an aging effect of "loss of material," and Note C. The staff reviewed the applicant's revision and found that the AMR result is consistent with the GALL Report for this combination of material, environment, and aging effect. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effect listed is appropriate for the combination of material and environment identified.

On the basis of its audit and review, the staff determines that, for AMRs not requiring further evaluation, as identified in LRA Table 3.1.1, the applicant's references to the GALL Report are acceptable and no further staff review is required.

3.1.2.1.1 AMR Results Identified as Not Applicable

LRA Table 3.1.1, Line Items 38 – 51 discuss the applicant's determination on GALL AMR line items that are applicable only to BWR-designed reactors. In the applicant AMR discussions for these items, the applicant indicates that the AMR Line Items 38 – 51 in Table 1 of the GALL Report, Volume 1 are not applicable to the IP2 and IP3 LRAs because IP2 and IP3 are Westinghouse-designed PWRs. The staff verified that AMR Line Items 38 – 51 in Table 1 of the GALL Report, Volume 1 are only applicable to BWR designed reactors, and that IP2 and IP3 are 4-Loop Westinghouse-design PWRs with dry ambient containments. Based on this determination, the staff finds that the applicant has provided an acceptable basis for concluding AMR Line Items 38 – 51 in Table 1 of the GALL Report, Volume 1 are not applicable to IP2 and IP3.

LRA Table 3.1.1, Line Item 54 addresses loss of material due to pitting, crevice, and galvanic corrosion of copper alloy piping, piping components, and piping elements exposed to closed cycle cooling water. The GALL Report recommends the closed-cycle cooling water system AMP to manage loss of material in these component groups. LRA Table 3.1.1, line item 56 addresses loss of material due to selective leaching in copper alloy >15 percent zinc piping, piping components, and piping elements exposed to closed cycle cooling water. The GALL Report recommends selective leaching of materials AMP to manage loss of material in these component groups. However, the LRA states that no copper alloy components exist in the Class 1 reactor vessel, vessel internals or reactor coolant pressure boundary and, therefore, these line items are not applicable. The staff verified from LRA Section 3.1.2.1 that there are no copper alloy components exposed to closed cycle cooling water at IP; therefore, the staff agrees that this line item is not applicable.

LRA Table 3.1.1, Line Item 75 addresses denting due to corrosion of carbon steel tube support plate in nickel alloy once-through steam generator (SG) tubes exposed to secondary feedwater/ steam. The GALL Report recommends steam generator tube integrity and water chemistry AMPs to manage denting in this component group. However, the LRA states that this line item applies to once through SGs, but IP2 and IP3 use recirculating SGs and, therefore, this line item is not applicable. The staff verified from LRA Section 2.3.1.4 that IP2 replaced its SGs in 2001 and IP3 replaced its SGs in 1989 with Westinghouse 44F recirculating models; therefore, the staff agrees that this line item is not applicable.

LRA Table 3.1.1, Line Item 77 addresses loss of material due to wastage and pitting corrosion in nickel alloy steam generator tubes and sleeves exposed to phosphate chemistry in secondary feedwater/ steam. The GALL Report recommends steam generator tube integrity and water chemistry AMPs to manage loss of material in these component groups. However, the LRA states that the IP SGs are not exposed to phosphate chemistry in secondary feedwater or steam and, therefore, this line item is not applicable. The staff verified the water chemistry for secondary water during the audit and determined that IP does not use phosphate chemistry in its water chemistry control program for secondary water/steam. Therefore, the staff finds this acceptable.

LRA Table 3.1.1, Line Item 78 addresses wall thinning due to flow-accelerated corrosion in steel steam generator tube support lattice bars exposed to secondary feedwater/ steam. The GALL Report recommends steam generator tube integrity and water chemistry AMPs to manage wall thinning in these component groups. However, the LRA states that IP SGs do not employ tube support lattice bars and, therefore, this line item is not applicable. The staff verified from LRA Table 3.1.2-4-IP2 and 3.1.2-4-IP3 that IP SGs employ stainless steel tube support plates instead of lattice bar types support plates; therefore, the staff agrees that this line item is not applicable.

LRA Table 3.1.1, Line Item 79 addresses denting due to corrosion of steel tube support plate in nickel alloy steam generator tubes exposed to secondary feedwater/ steam. The GALL Report recommends steam generator tube integrity and water chemistry AMPs. For plants that could experience denting at the upper support plates, the GALL Report recommends that the potential for rapidly propagating cracks be evaluated, and for applicants to develop and take applicable corrective actions consistent with staff's recommendations in NRC Bulletin 88-02. However, LRA states that IP SG tube support plates are made out of stainless steel and, therefore, this line item is not applicable. The staff verified from LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3 that IP SGs employ stainless steel tube support plates instead of carbon steel support plates; therefore, the staff agrees that this line item is not applicable.

LRA Table 3.1.1, Line Item 82 addresses cracking due to SCC in stainless steel steam generator primary side divider plate exposed to reactor coolant. The GALL Report recommends water chemistry AMP to manage SCC in this component. However, the LRA states that the IP SG divider plates are made out of nickel alloy and, therefore, this line item is not applicable. The staff verified from LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3 that the IP SGs employ nickel alloy channel head divider plates; therefore, the staff agrees that this line item is not applicable.

LRA Table 3.1.1, Line Item 84 addresses cracking due to SCC in nickel alloy SG components such as, secondary side nozzles (vent, drain, and instrumentation) exposed to secondary feedwater/ steam. The GALL Report recommends water chemistry and one time inspection or inservice inspection AMPs to manage SCC in this component. However, LRA Table 3.1.2-4-IP2 does not contain a similar entry for the IP2 SGs. The staff questioned the applicant in Audit Item 210 regarding this dissimilarity. In its response, dated December 18, 2007, the applicant stated that only IP3 has a nickel alloy RTD boss component; therefore, the staff finds this acceptable.

LRA Table 3.1.1, Line Item 87 addresses no aging effect in steel piping, piping components, and piping elements in concrete. The GALL Report recommends no aging management programs since there is no aging effect applicable to these components when buried in concrete. However, the LRA states that IP does not have components of the Class 1 reactor vessel, vessel internals or reactor coolant pressure boundary exposed to concrete and, therefore, this line item is not applicable. The staff confirmed during an audit that IP does not have any such components buried in concrete and, therefore, the staff finds this acceptable.

3.1.2.1.2 Cracking Due to Stress Corrosion Cracking, Loss Of Material Due to Wear, and Loss of Preload Due to Thermal Effects, Gasket Creep, and Self-Loosening of Bolting

LRA Table 3.1.1, Line Item 52 (LRA AMR 3.1.1-52) addresses cracking due to SCC, loss of material due to wear, and loss of preload due to thermal effects, gasket creep, and self-loosening of steel and stainless steel reactor coolant pressure boundary (RCPB) pump and valve closure bolting, manway and holding bolting, flange bolting, and closure bolting in high-pressure and high-temperature systems. The GALL Report recommends the bolting integrity AMP to manage these aging effects.

The GALL AMR that corresponds to LRA AMR 3.1.1-52 identifies that cracking due to SCC, loss of material due to wear, and loss of preload due to thermal effects, gasket creep, and self-loosening are applicable aging effects requiring management for steel and stainless steel reactor coolant pressure boundary (RCPB) pump and valve closure bolting, manway and holding bolting, flange bolting, and closure bolting in high-pressure and high-temperature systems.

The staff noted that the LRA indicated that GALL item is not applicable to IP2 and IP3 because the applicant did not consider cracking due to SCC, loss of preload due to stress relaxation, or loss of material due to wear to be applicable AERM for the bolts used in the RCS bolted connections. In particular, the applicant indicated that cracking due to SCC is not an AERM for these bolts because the RCS bolts that were purchased and used under the applicant’s QA program were of low to moderate tensile strengths. The applicant also indicated that its AMR process concluded that loss of material due to wear was not a significant aging effect and that loss of preload is an event driven condition.

The staff also noted that, since LRA AMR 3.1.1-52 did not identify any AERMs for the ASME Code Class 1 bolting in the reactor vessel, or RCS piping or steam generator designs, Tables 3.1.2-1-IP2, 3.1.2-1-IP3, 3.1.2-3-IP2, and 3.1.2-3-IP3 do not identify any applicable aging effects for the ASME Code Class 1 bolting used in RV and ASME Code Class 1 piping designs at IP2 and IP3.

For bolting components, the staff in Table IX.E of the GALL Report, Volume 2 identifies cracking and loss of preload as applicable potential aging effects for license renewal applications. Table IX.F of the GALL Report, Volume 2, identifies that SCC is an applicable mechanism that may lead to cracking of metallic components. Table IX.F of the GALL Report, Volume 2, indicates that wear is a mechanism that may lead to loss of material; that SCC is a mechanism that can lead to cracking; and that stress relaxation and thermal effects, gasket creep, and self-loosening are all potential aging mechanisms that may lead to loss of preload in bolted connections.

The staff did not accept the applicant’s position that there are not any AERMs for the RCS bolting components because the applicant’s position differed from the staff’s recommendation in GALL AMRs IV.A2-6, IV.A2-7, IV.A2-8, IV.C2-7, IV.C2-8, IV.D1-2, and IV.D1-10, and from the aging effect/aging effect criteria for bolted assembly components in Tables IX.E and IX.F of the GALL Report, Volume 2. During an audit, the staff asked the applicant to clarify its position on the aging management of Class 1 bolting within the RCS (Audit Item 201).

The applicant provided the following response in a letter dated December 18, 2007, and amended LRA AMR 3.1.1-52 as follows:

> ~~Not applicable.~~
> High strength low alloy steel is not used for these bolting applications at IPEC. ~~Applied stress For stainless steel closure bolting applications should be much less than 100 ksi.~~ Consequently, cracking of bolting due to stress corrosion cracking is not an aging mechanism requiring management. Industry operating experience indicates that loss of material due to wear is not a significant aging effect for this bolting. Occasional thread failures due to wear related

> mechanisms, such as galling, are event driven conditions that are resolved as required. Loss of preload is a design driven effect and not an aging effect requiring management. Bolting at IPEC is standard grade B7 low alloy steel, or similar material, except in rare specialized applications such as where stainless steel bolting is utilized. Loss of preload due to stress relaxation (creep) would only be a concern in very high temperature applications (> 700 °F) as stated in the ASME Code, Section II, Part D, Table 4. No IPEC bolting operates at > 700 °F. Therefore, loss of preload due to stress relaxation (creep) is not an applicable aging effect for the reactor coolant system. Other issues that may result in pressure boundary joint leakage are improper design or maintenance issues. Improper bolting application (design) and maintenance issues are current plant operational concerns and not related to aging effects or mechanisms that require management during the period of extended operation. Nevertheless, the Bolting Integrity Program manages loss of preload for all external bolting in the reactor coolant system with the exception of the reactor vessel studs. As described in the Bolting Integrity Program, IPEC has taken actions to address NUREG-1339, *Resolution to Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants.* These actions include implementation of good bolting practices in accordance with EPRI NP-5067, "Good Bolting Practices." Proper joint preparation and make-up in accordance with industry standards is expected to preclude loss of preload. This has been confirmed by operating experience at IPEC.

The staff noted that SRP-LR Section A.1.2.1 provides the staff's position that leakage past a bolted connection is not to be treated as an abnormal event and that the aging effects leading to such leaking or resulting from such leakage need to be evaluated for the period of extended operation. This section of the SRP also states that:

> Specific aging effects from abnormal events need not be postulated for license renewal. However, if an abnormal event has occurred at a particular plant, its contribution to the aging effects on structures and components for license renewal should be considered for that plant. For example, if a resin intrusion has occurred in the reactor coolant system at a particular plant, the contribution of this resin intrusion event to aging should be considered for that plant.
>
> However, leakage from bolted connections should not be considered as abnormal events. Although bolted connections are not supposed to leak, experience shows that leaks do occur, and the leakage could cause corrosion. Thus, the aging effects from leakage of bolted connections should be evaluated for license renewal.

The staff reviewed the applicant's LRA AMR items relative to the applicable aging effects for SA-193, Grade B7 bolting components, as amended in the applicant's response to Audit Item 201. The staff noted that, with respect to the management of cracking due to SCC in the applicant's SA-193 Grade B7 bolts, the information in the LRA indicates that the cracking due to SCC would not be an aging effect requiring management (AERM) because the bolting components were procured to yield strengths less than 150 ksi (i.e. the applicant has indicated that the RCS bolts that were purchased and used under the applicant's QA program were of low to moderate tensile strengths, meaning the yield strengths for the materials are even lower. In the staff's safety evaluation on WCAP-14574-NP-A dated October 26, 2000, the staff provided its basis that cracking due to SCC does not need to be managed in SA-193 Grade B7 bolting materials if it was confirmed that the materials for the bolting components were procured to either yield strengths less than 150 ksi (considered high yield strengths) or to hardness values less than or equal to 32 on a Rockwell C Hardness scale. The staff finds that the applicant has provided an acceptable basis for concluding that cracking due to SCC is not an aging effect requiring management for these bolting components because it is consistent with the staff's basis in its SE on WCAP-14574-NP-A that cracking of SA-193, Grade B7 would not need to be managed if the materials for the bolting components were procured to either yield strengths less than 150 ksi or to hardness values less than or equal to 32 on a Rockwell C Hardness scale.

The staff noted, however, that the applicant's response to Audit Item 201 also indicated that loss of material due to wear and loss of preload due to stress relaxation were not aging effects and mechanisms that need to be managed in the SA 193, Grade B7 bolting components. However, in spite of this basis, the staff did note that the applicant's response to Audit Item 201 did indicate that these bolting components are included within the scope of the applicant's Bolting Integrity Program. Thus, the staff finds that by including the SA-193 Grade B7 bolting within the scope of the Bolting Integrity Program, the applicant will manage any loss of material, loss of preload, or potential cracking of the bolting that may occur during the period of extended operation. Audit Item 201 is resolved.

3.1.2.1.3 Cracking Due to Cycling Loading, Stress Corrosion Cracking, and Primary Water Stress Corrosion Cracking

LRA Table 3.1.1, Line Item 62 (LRA AMR 3.1.1-62) addresses cracking due to cyclic loading in stainless steel, steel with stainless steel cladding reactor coolant system cold leg, hot leg, surge line, and spray line piping and fittings exposed to reactor coolant. AMR Item 62 in Table 1 of the GALL Report, Volume 1 (GALL1 AMR 1-62) recommends an AMP corresponding to GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," be credited to manage cracking due to cyclical loading in these components.

In LRA AMR 3.1.1-62, the applicant stated that GALL1 AMR 1-62 was not used because cracking due to cyclic loading is addressed in other LRA AMR items on cracking due to fatigue. In this AMR Item, the applicant also stated that in spite of this fact, the Inservice Inspection Program is credited to manage cracking of all ASME Code Class 1 stainless steel piping that is greater than four (4) inches in diameter (i.e., 4-inch NPS). Because the applicant did not use the GALL1 AMR item, the staff did not find any applicable AMRs in LRA Tables 3.1.2-3-IP2 and 3.1.2-3-IP3 on cracking in these large bore ASME Code Class 1 piping, piping components, or piping elements. In Audit Item 203, the staff asked the applicant to clarify its position on this component group.

The applicant responded to Audit Item 203 in a letter dated December 18, 2007. In this response, the applicant stated:

> Cracking due to cyclic loading is addressed in other items as cracking due to fatigue. The Inservice Inspection Program manages cracking of stainless steel piping > 4" nps.
>
> Table 3.1.2-3-1P2 and Table 3.1.2-3-1P3 line item "piping >4" nps / Treated borated water >140 deg F (int) / Cracking" is revised to add the following NUREG-1 801 Vol. 2 item, Table 1 item, and Note.

IV.C2-26 (R-56) / 3.1.1-62 / E

Information to be incorporated into the LRA.

The staff verified that the applicant made the stated changes to the LRA in the letter of December 18, 2007, and that the changes made to LRA AMR 3.1.1-62 are consistent with the position in GALL1 AMR 1-62. The staff also verified that, by the same letter, the applicant amended the AMRs on cracking of large bore piping in LRA Tables 3.1.2-3-IP2 and 3.1.2-3-IP3 to be consistent with the AMR in GALL AMR Item IV.C2-26. Based on the applicant's response and the applicant's amendment of the LRA, the staff confirmed that the applicant amended its AMRs on cracking due to cyclical loading of the large bore ASME Code Class 1 piping at IP2 and IP3 to be consistent with the staff's position provided in the GALL Report recommending the Inservice Inspection Program be credited to manage cracking due to cyclical loading of these components. Based on the staff's review and confirmation of the appropriate amendments of the LRA, the staff finds that the applicant has proposed an acceptable basis for managing cracking due to cyclical loading in these large bore ASME Code Class 1 piping, piping components, and piping elements because the applicant's basis is consistent with the staff's position in the GALL Report.

LRA Table 3.1.1, Line Item 64 (LRA AMR 3.1.1-64) addresses cracking due to SCC or primary water stress corrosion cracking (PWSCC) in stainless steel and steel with stainless steel or nickel alloy cladding pressurizer components. The AMR that corresponds to LRA AMR 3.1.1-64 is AMR Item 64 in the GALL Report, Volume 1 (GALL1 AMR Table 1-64), This GALL AMR invokes GALL AMR IV.C2-19 and together these AMRs recommend that programs corresponding to GALL AMPs XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and XI.M2, "Water Chemistry," be credited to manage cracking in pressurizer components that are made from either stainless steel or steel with internal stainless steel or nickel alloy cladding.

The staff noted that the LRA indicated that the Water Chemistry Control Program – Primary and Secondary and Inservice Inspection Program are credited to manage cracking in steel with stainless steel or nickel alloy clad components and the management of cracking in the stainless steel components is addressed in other LRA Table 3.1.1 AMR items.

The staff asked the applicant to identify the additional pressurizer component AMRs that are used to manage cracking of the stainless steel pressurizer components or steel pressurizer components that are designed with internal stainless steel or nickel alloy cladding (Audit Item 204). In its response, dated December 18, 2007, the applicant stated that AMRs on cracking of the IP2 and IP3 pressurizer components are given in LRA Tables 3.1.2-3-IP2 and 3.1.2-3-IP3, respectively. The applicant also stated that these AMR items include those for the pressurizer heater sheaths, heater wells, manway insert plates, pressurizer penetrations, pressurizer spray heads, pressurizer spray head couplings and locking bars, thermal sleeves, and thermowells. The applicant further stated that the Table 1 rollup items for these components are Items 3.1.1-24, 3.1.1-68, or 3.1.1-70.

Regarding the applicant's response to the Table 2 AMR on cracking of the CASS pressurizer spray heads (as given in LRA Table 3.1.2-3-IP2 and 3.1.2-3-IP3), the staff noted that the applicant aligned the Table 2 AMR to LRA AMR Item 3.1.1-24. SER Section 3.1.2.2.7, Subsection (2) documents the staff's evaluation of the applicant's Table 2 AMR on cracking of the CASS pressurizer spray head.

Regarding the applicant's response to the Table 2 AMR on cracking of the IP2 pressurizer heater sheaths, heater wells, manway insert plates, pressurizer penetrations, pressurizer spray head couplings and locking bars, pressurizer thermal sleeves, and thermowells, the staff noted that the applicant aligned its Table 2 AMR items for these components to LRA AMR Item 3.1.1-68. The staff's evaluation of the applicant's Table 2 AMR items for these components is documented later in this SER section.

The staff noted that the LRA did not include any AMRs on cracking of the steel pressurizer shell or head components (with internal stainless steel cladding) that aligned to GALL AMR IV.C2-19. Although the LRA did include some AMRs on cracking of the steel pressurizer shell courses and heads that are clad internally with stainless steel, the applicant aligned its AMRs on cracking of these pressurizer components to LRA AMR 3.1.1-67 and to GALL AMR IV.C2-18. These pertain to cracking in pressurizer components induced by cyclical loading (fatigue). The staff also noted that in these AMRs the applicant credited its Inservice Inspection Program to manage cracking in pressurizer components. This is the same program recommended in GALL AMR IV.C2-19 for managing cracking in the components if the cracking is induced by SCC or PWSCC. Thus, the staff concludes the alignment on cracking of these pressurizer shells and heads (including internal stainless steel cladding) to LRA AMR 3.1.1-67 and to GALL AMR IV.C2-18 adequately covers both alignment to LRA 3.1.1-67 and GALL AMR IV.C2-18 and to LRA AMR 3.1.1-64 and GALL AMR IV.C2-19. This is because the volumetric inservice inspections for these components would detect for cracking initiated by cyclical loading (fatigue) or by SCC or PWSCC. Therefore, the staff finds that the applicant has adequately addressed cracking in the steel pressurizer head and shells that are clad internally with stainless steel and are exposed to the reactor coolant.

The staff also noted that, in LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3, the applicant also aligned the following AMRs for steel RV components that are clad internally with stainless steel to GALL AMR IV.C2-19, including those for the RV closure heads, RV closure head flanges, RV shell flanges, RV inlet and outlet nozzles, RV closure head vents, RV upper shells, RV intermediate shells, RV lower shells, and associated welds. The staff noted that in these AMRs, the applicant credited its Water Chemistry Control Program – Primary and Secondary and Inservice Inspection Program for aging management of the components. The staff finds this to be acceptable because these RV components have the same material, environment, and aging effect combinations as those for the steel pressurizer components that are clad internally with stainless steel or nickel alloy materials and because the applicant's aging management basis for these RV components is consistent with the staff's recommended position in GALL AMR IV.C2-19.

LRA Table 3.1.1, Line Item 65 (LRA AMR 3.1.1-65) addresses cracking due to PWSCC in nickel alloy upper reactor vessel closure head (RVCH) control rod drive penetration nozzles, instrument tubes, head vent pipes (top head), and welds, and in the nickel alloy reactor vessel (RV) inlet and outlet nozzle safe-end welds. Item 65 in Table 1 of the GALL Report, Volume 1 (GALL1 AMR 1-65), which corresponds to LRA AMR 3.1.1-65, invokes GALL AMRs IV.A2-9 and IV.A2-18, as applicable to the management of cracking in control rod drive (CRD) penetration nozzles and upper RVCH head vent pipes and instrumentation tubes, and their associated nickel alloy nozzle-to-RV welds. Collectively, these GALL-based AMRs all recommend that programs corresponding to GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," GALL AMP XI.M2, "Water Chemistry," and GALL AMP XI.M11A, "Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure

Heads of Pressurizer Water Reactors," manage cracking in these nickel alloy nozzle components and their associated nickel alloy nozzle-to-RV penetration welds.

The staff noted that in LRA AMR Item 3.1.1-65, the applicant credited only its Water Chemistry Control Program – Primary and Secondary (LRA AMP B.1.41) and the Nickel Alloy Inspection Program (LRA AMP B.1.21) to manage cracking in the nickel alloy upper RVCH penetration nozzles or any upper RVCH nozzles that are welded to the upper RVCH using nickel alloy nozzle-to-RV penetration welds, and in the nickel alloy RV inlet and outlet nozzle safe-end welds. The staff had two issues with this aging management basis: (1) the applicant did not credit its Inservice Inspection Program, as is otherwise recommended in the applicable GALL AMRs, and (2) in LRA AMR. 3.1.1-65, the applicant credited its general nickel alloy aging management program for the upper RVCH penetration nozzle and its associated nickel alloy nozzle-to-RV welds. The staff addressed these issues in Audit Item 205.

In its response dated December 18, 2007, the applicant amended AMR line items in LRA Table 3.1.2-1-IP2 and LRA Table 3.1.2-1-IP3 to add the applicant's Inservice Inspection Program to the Water Chemistry Program and the Nickel Alloy Inspection Program as the basis for managing cracking due to PWSCC. The staff noted that the applicable components included the upper RVCH head vent safe end and their associated welds and the nickel alloy RV inlet and outlet nozzle safe-end welds. The staff noted that addition of the Inservice Inspection Program will make the AMRs for these penetration nozzles consistent with the staff's recommended AMR guidance in GALL1 AMR 1-65.

With respect to aging management of cracking in nickel alloy RV inlet and outlet nozzle safe-end welds, the staff's basis in GALL AMR IV.A2-15 recommends Inservice Inspection Programs be credited for aging management. This is because the RV inlet and outlet nozzle safe end welds are ASME Code Class 1 full penetration butt welds that are required to be inspected by volumetric inspection techniques once every 10-year ISI Interval. These volumetric examinations are also required to be subject the NRC's performance demonstration initiative requirements (PDI) that are defined and required in 10 CFR 50.55a. Thus, the staff found that the applicant's response to Audit Item 205 and LRA amendment of the Table 2 AMR entry on cracking of the nickel alloy RV inlet and outlet nozzle safe-end welds resolved the staff's issue with respect to these components. This is because the addition of the Inservice Inspection Program as an added basis for aging management makes the AMR entry for these components consistent with the staff aging management recommendations in IV.A2-15, with the added conservatism that the Nickel Alloy Inspection Program is also credited for aging management of cracking in these nickel alloy components.

The staff determined that the applicant's response to Audit Item 205 and the LRA amendment provided in the December 18, 2007, letter did not resolve the issue with respect to the AMPs that should be credited for aging management of cracking in the upper RVCH penetration nozzles. The staff's basis for this finding is as follows: GALL1 AMR 1-65, and GALL AMRs IV.A2-9 and IV.A2-18, which derive from this GALL1 AMR, deal only with management of cracking due to PWSCC in nickel alloy upper RVCH penetration nozzles in PWRs (including CRD penetration nozzles, and upper RVCH head vent and instrumentation nozzles), and their associated nickel alloy nozzle-to-RV welds.[7] These GALL AMRs recommend that programs that

[7] GALL1 AMR 1-65, and GALL AMRs IV.A2-9 and IV.A2-18 are only applicable to CRD penetration nozzles and upper RV head vent nozzles and their nickel alloy welds and are not applicable to CRD pressure housings. The GALL AMRs on cracking of CRD pressure housings is addressed in AMR Item 34 of Table 1 to the GALL Report, Volume 1 (GALL1 AMR 1-34), and in GALL AMR IV.A2-11 which is derived from this GALL1 AMR. The GALL AMRs on

correspond to GALL AMP XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD,” GALL AMP XI.M2, “Water Chemistry,” and GALL AMP XI.M11A, “Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors,” be credited to manage cracking due to PWSCC in these upper RVCH nickel alloy components. In contrast, the applicant’s AMR entry in LRA 3.1.1-65 for any upper RVCH nozzles made from nickel alloy base metals and are welded to the upper RVCH using nickel alloy nozzle-to-RV welds or for any non-nickel alloy RVCH nozzles that are welded to the upper RVCH using nickel alloy nozzle-to-RV welds, in part, credited AMP B.1.21, Nickel Alloy Inspection Program. In addition, B.1.31, Reactor Vessel Head Penetration Inspection Program and GALL AMP XI.M11A are based on compliance with the staff’s augmented inspection requirements for PWR upper RVCH penetration nozzles, as issued in NRC Order EA-03-009, and amended in the First Revised Order EA-03-009 (henceforth referred to as the “Order as Amended”). Thus, the applicant’s entry in LRA AMR 3.1.1-65 should specify that AMP B.1.31, Reactor Vessel Head Penetration Inspection Program is credited for aging management, because that is the applicant’s nickel alloy management program that corresponds to GALL AMP XI.M11A, "Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors (PWRs Only)," and not AMP B.1.21, Nickel Alloy Inspection Program, which is not based on compliance with the Order as Amended.[8]

The staff reviewed LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3 to see if the applicant’s Table 2 AMRs on cracking of the upper RVCH nozzles appropriately credited the proper AMPs recommended in GALL AMRs IV.A2-9 and IV.A2-18. The staff noted that the applicant includes only one AMR entry each in LRA Table 3.1.2-1-IP2 and Table 3.1.2-1-IP3 for its nickel alloy RVCH penetration nozzles (which is the AMR entry for the CRD head penetration housing tubes [nozzles]) and that in this Table 2 AMR item entry, the applicant appropriately credited its Reactor Vessel Head Penetration Inspection Program, along with the Water Chemistry Control Program – Primary and Secondary and the Inservice Inspection Program, to manage cracking of the components. However, the staff also noted that the applicant inappropriately aligned this Table 2 AMR item to LRA AMR 3.1.1-34 which is for CRD pressure housings, and not to LRA 3.1.1-65, which is the appropriate Table 1 AMR for CRD penetration nozzles and upper RVCH head vent and instrumentation nozzles. The staff also noted that the applicant’s Table 2 AMRs in LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3 did include an entry on cracking of the upper RVCH head vent nozzles and that in these AMR items, the applicant identified that the upper RVCH head vent nozzle was made of carbon steel with stainless steel cladding. However, the staff noted that the AMRs entries on the upper RVCH head vent nozzles did not clarify whether the head vent nozzle-to-RV weld for the upper RVCH head vent nozzles were made of nickel alloy filler weld material. Thus, the staff determined that the application’s AMR inputs for the upper RVCH penetration nozzles and CRD pressure housings needed additional information and clarification.

---

cracking of RV inlet and outlet nozzles safe ends and safe end welds is addressed in AMR Item 69 of Table 1 to the GALL Report, Volume 1 (GALL1 AMR 1-69), and in GALL AMR IV.A2-15 which is derived from this GALL1 AMR.

[8] For the Table 2 AMR entries on cracking in LRA Table 3.1.2-1-IP2 and 3.1.2-1-IP3 for the CRD penetration housing tubes (i.e., the CRD penetration nozzles), the staff noted that the applicant appropriately credited, in part, LRA AMP B.1.31, Reactor Vessel Head Penetration Inspection Program for aging management. Thus, the issue is with the general AMR basis discussed in LRA AMR 3.1.1-65 for upper RVCH penetrations, and with a question on whether the upper RVCH vent nozzles and any upper RVCH instrumentation nozzles are welded to the upper RVCHs using nickel alloy nozzle-to-RV welds.

In a letter dated December 30, 2008, the staff issued RAI 3.1.2-1, Part A to resolve these issues. This was identified as part of Open Item 3.1.2-1.

The applicant responded to RAI 3.1.2-1 in a letter dated January 27, 2009. In this response, the applicant clarified that the CETNA nozzles used in the upper RV head designs are fabricated from stainless steel and do not include any nickel alloy base metal or weld materials. Instead, the applicant clarified that the CETNA assemblies are fabricated as follows:

"A CET head port adapter is connected to the penetration housing adapter flange, and then connected to the CETNA assembly via a conoseal joint. All CETNA assemblies are sealed to the CET columns with Grafoil seals using a compression collar and a hold down nut with no welds. As shown in the LRA Tables, the CETNA are constructed from stainless steel."

Based on this supplemental information, the applicant has provided an acceptable basis for concluding that the CETNA assemblies do not need to be within the scope of and managed by the Nickel Alloy Inspection Program because these components do not include any nickel alloy base metal or weld components.

In the applicant's response to RAI 3.1.2-1, the applicant also clarified that the only nickel alloy welds associated with the upper RVCH vent nozzles are those nickel alloy welds that join these nozzles to the nickel alloy closure head vent nozzle safe-end. The applicant explained the vent nozzles are carbon steel nozzles with internal stainless steel cladding that are welded to the carbon steel upper RVCH using carbon steel weld materials that have been post weld heat treated. The applicant clarified that the nickel alloy welds associated with the nickel alloy vent nozzle safe ends are within the scope of the applicant's Nickel Alloy Inspection Program. Based on this review, the staff finds that the applicant has provided an acceptable basis for concluding that the upper RVCH head vent nozzle-to-upper RVCH welds do not need to be managed by or be within the scope of the either the Nickel Alloy Inspection Program or Reactor Vessel Head Penetration Inspection Program because these components and their associated welds are not fabricated from nickel alloy materials.

Based on this review, the staff finds that the applicant has provided an acceptable basis for managing cracking in these upper RVCH head vent nozzles and CETNA nozzles because: (1) the applicant has clarified which of nozzle designs include nickel alloy base metal or weld materials, (2) the applicant has appropriately credited its Nickel Alloy Inspection Program and Water Chemistry Program to manage cracking in the nickel alloy upper RVCH head vent nozzle safe ends and their nickel alloy safe-end-to-nozzle welds, and (3) in the applicant's AMRs for the CETNA nozzles and upper RVCH head vent nozzles, as given in LRA Tables 3.1.2-IP2-1 and 3.1.2-IP3, the applicant has appropriately credited its Water Chemistry Program and Inservice Inspection Program for any cracking that may develop in the components. RAI 3.1.2-1 is resolved and Open Item 3.1.2-1 is closed with respect to the management of cracking in the upper RVCH head vent nozzles and the CETNA nozzles.

LRA Table 3.1.1, Line Item 69 (LRA AMR Item 3.1.1-69) addresses cracking due to SCC and PWSCC in stainless steel and nickel alloy safety injection nozzles, safe ends, and associated welds and buttering exposed to reactor coolant. AMR Item 69 in Table 1 of the GALL Report, Volume 1 (GALL1 AMR 1-69) is the GALL AMR that corresponds to LRA AMR 3.1.1-69. In this GALL1 AMR, and in GALL AMR IV.A2-15, the staff recommends that AMPs corresponding to GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD," and GALL AMP XI.M2, "Water Chemistry," be credited to manage cracking in these components under exposure to the reactor coolant.

The staff verified that, in LRA Table 3.1.2-1-IP2, the applicant includes two AMRs that aligned to GALL AMR IV.A2-15: (1) cracking of the stainless steel reactor vessel (RV) inlet and outlet nozzle safe-ends, and (2) cracking of the stainless steel RV bottom head safe-ends and safe-end welds. In these AMRs, the staff noted that the applicant credited its Water Chemistry Control Program – Primary and Secondary and its Inservice Inspection Program to manage cracking in the stainless steel component surfaces that are exposed to the reactor coolant. This is in conformance with the recommendation in GALL AMR IV.A2-15, that AMPs corresponding to GALL AMP XI.M1, “ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD,” and GALL AMP XI.M2, “Water Chemistry,” be credited to manage cracking in stainless steel RV inlet nozzle, outlet nozzle and safety injection nozzle safe end components and their associated nickel alloy safe-end welds.

In Audit Item 208, the staff asked the following question:

> In LRA Table 3.1.1, Item 3.1.1-69, Entergy states, The Water Chemistry Control - Primary and Secondary and Inservice Inspection Programs manage cracking in stainless steel nozzles and penetrations. Nickel alloy used for such applications is compared to other lines. Identify which other lines applicable to Ni-alloy components exposed to reactor coolant and manage cracking due to SCC and PWSCC.

In its response, dated December 18, 2007, the applicant stated the LRA AMR 3.1.1-69 is a rollup only for the stainless steel RV inlet and outlet nozzle safe-ends and the safe ends and safe-end welds on the bottom head drains. The applicant stated that the LRA Tables 3.1.2-1-IP2 through 3.1.2-4-IP2 and LRA Tables 3.1.2-1-IP3 through 3.1.2-4-IP3 include numerous AMR items for nickel alloy components. Examples are the control rod drive penetrations, the RV inlet/outlet nozzle safe end welds, and the bottom head instrument penetrations. The applicant stated that these AMR items are compared to Items IV.A2-18 and IV.A2-19, which roll up to table entries 3.1.1-31 and 3.1.1-65. The applicant stated that the AMR in LRA AMR 3.1.1-69 is only for management of cracking in the RV inlet and outlet nozzle safe-ends and the RV bottom head drain safe-ends.

The staff reviewed LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3 to determine whether the information in the applicant’s response to Audit Item 208 was valid with respect to the applicant’s basis for managing cracking due to SCC or PWSCC in the nickel alloy components associated with the RV bottom heads. The staff noted that, in the applicant’s response to Audit Item 208, the applicant mentioned that the nickel alloy components in the RV bottom heads, which align to LRA AMR 3.1.1-69, are the nickel alloy safe-ends for the RV bottom head drains. However, the staff also noted that LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3 do not include any AMR entries for RV bottom head drains or specifically for nickel alloy bottom head drain safe ends and welds. Thus, the staff determined that the applicant would need to better define which of the components and welds associated with the RV bottom heads are made from nickel alloy materials and what the applicant’s basis is for managing cracking due to SCC or PWSCC in these nickel alloy RV bottom head components and welds. By letter dated December 30, 2008, the staff issued RAI 3.1.2-1, Part B to resolve this issue. The staff’s acceptance of LRA AMR 3.1.1-69 is pending acceptable resolution of RAI 3.1.2-1, Part B on aging management of nickel alloy components that are associated with the RV bottom heads or their penetration nozzles. This was identified as part of Open Item 3.1.2-1.

By letter dated January 27, 2009, the applicant responded to RAI 3.1.2-1, Part B. In this response, the applicant clarified that neither the IP2 nor IP3 reactor vessels have bottom head drains, and that the response to Audit Item 208 should have referred to the nickel alloy welds in bottom head safe ends instead of the bottom head drain safe end welds. The staff noted that the clarification made in the response to RAI 3.1.2-1, Part B is consistent with the actual design of the RV bottom head nozzle at IP2 and IP3. The staff finds this response provides an acceptable basis for resolving which components in RV bottom heads are fabricated with nickel alloy welds because the clarification is consistent with the actual design of IP2 and IP3 RV bottom heads. The staff confirmed that the LRA indicates that the applicant is crediting its Water Chemistry Control Program, the Inservice Inspection Program, and the Nickel Alloy Inspection Program to manage cracking due to PWSCC in the RV bottom head instrumentation nozzles and their nickel alloy safe end welds. This is consistent with the AMPs recommended for aging management in GALL AMR Item IV.A2-19. RAI 3.1.2-1, Part B is resolved and Open Item 3.1.2-1 is closed with respect to identifying which of the RV bottom head components and associated welds are fabricated from nickel alloy materials.

In LRA Tables 3.1.2-3-IP2 and 3.1.2-3-IP3, the applicant includes AMRs on cracking of the stainless steel regenerative heat exchanger bonnet, shell, and tube surfaces that are exposed to borated treated water (i.e. to the reactor coolant). The applicant aligned these AMRs to LRA Table 3.3.1, AMR item 3.3.1-8, which states "Stainless steel components of some heat exchangers to which this NUREG-1801 line item applies, including the regenerative heat exchanger, are in the reactor coolant systems in series 3.1.2-x tables." SER Section 3.3.2.2.4, Item (2) documents the staff's evaluation of these AMRs.

LRA Table 3.1.1, Line Item 68 (LRA AMR 3.1.1-68) addresses cracking due to SCC in Class 1 piping, fittings, pump casings valve bodies, nozzles, safe ends, manways, flanges, CRD housing; pressurizer heater sheaths, sleeves, diaphragm plate; pressurizer relief tank components; reactor coolant system cold leg, hot leg, surge line, and spray line piping and fittings that are made from either stainless steel or steel with internal stainless steel cladding. AMR Item 68 in Table 1 of the GALL Report, Volume 1 (GALL1 AMR 1-68) is the GALL AMR that corresponds to LRA AMR 3.1.1-68. In this GALL1 AMR, and in GALL AMRs IV.C2-2, IV.C2-5, IV.C2-20, IV.C2-22, IV.C2-27, and IV.D1-1 which are invoked by this GALL1 AMR, the staff recommends that AMPs corresponding to GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and GALL AMP XI.M2, "Water Chemistry," be credited to manage cracking in these components.

The staff noted that in the LRA, the applicant credited its Water Chemistry Control Program – Primary and Secondary and its Inservice Inspection Program to manage cracking in all ASME Code Class 1 reactor coolant pressure boundary components that are subject to inservice inspections. This includes the stainless steel (including CASS) ASME Code Class 1 large bore (≥ 4-inch NPS) piping, piping components, piping elements; pump casings; large bore (≥ 4-inch NPS) valve bodies, pressurizer penetration nozzles, pressurizer manway inserts, pressurizer heater sheaths and wells, and pressurizer thermal sleeves; SG primary manways, and SG primary nozzles. The staff finds that the applicant's aging management basis for managing cracking in these components is acceptable because the crediting of the Water Chemistry Control Program – Primary and Secondary and the inservice Inspection Program is consistent with the programs recommended for aging management in GALL1 AMR 1-68 and GALL AMRs IV.C2-2, IV.C2-5, IV.C2-20 and IV.D1-1.

For the non-ASME Code Class 1 (non-pressure boundary) stainless steel components in the RCS, including the pressure spray head couplings and locking bars and the primary SG manway cover inserts, the applicant credited only its Water Chemistry Control Program – Primary and Secondary to manage cracking in the components.

The staff noted that the applicant did not credit an inspection-based program to verify the effectiveness of the Water Chemistry Control Program – Primary and Secondary in managing cracking of these stainless steel non-ASME Code Class 1 (non-pressure boundary) components. In Audit Item 207, the staff asked the applicant to justify its basis for crediting only the Water Chemistry Control Program – Primary and Secondary for management of cracking in the pressurizer spray head couplings and locking bars, and for not crediting a One Time Inspection to verify the effectiveness of Water Chemistry Control Program – Primary and Secondary in managing this aging effect. In Audit Item 357, the staff asked the applicant to justify its basis for crediting only the Water Chemistry Control Program – Primary and Secondary as the basis for managing cracking in the SG primary manway cover inserts and why the Inservice Inspection Program had not been credited for cracking in these components.

In its response to Audit Items 207 dated December 18, 2007, the applicant clarified that the pressurizer spray head couplings and locking bars are not AMSE Code Class components and, therefore, these couplings and locking bars are not within the scope of the applicant's Inservice Inspection Plan. The applicant clarified that a One Time Inspection will be used to verify the effectiveness of the Water Chemistry Control Program – Primary and Secondary in managing cracking of the pressurizer spray head couplings and locking bars as a result of SCC.

In its response to Audit Item 357 dated December 18, 2007, the applicant clarified that the primary SG manway cover inserts are ASME Code Class 1 components and that these components are within the scope of the applicant's Inservice Inspection Program. As a result, the applicant stated that it is crediting both the Water Chemistry Control Program – Primary and Secondary and the Inservice Inspection Program to manage cracking of the primary SG manway inserts and that the applicable Table 2 AMRs in LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3 for the primary SG manway insert would be amended accordingly.

With respect to the applicant's response to Audit Item 357, the staff verified that the applicant made the appropriate changes to the AMRs on cracking of the primary SG manway cover inserts in the LRA amendment dated December 18, 2007. The staff also verified that this change makes the AMRs in LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3 for the primary SG manway cover inserts consistent with the aging management guidance in GALL1 AMR 1-68 and GALL AMR IV.D1-1. Based on this LRA amendment the staff finds that the applicant's AMRs on cracking of the primary SG manway cover inserts are acceptable because the applicant's amended AMRs for the components have been verified as being consistent with staff's recommended aging management position that is provided in GALL AMR IV.D1-1. The staff also confirmed that, in the applicant's AMRs in LRA Table 3.1.2-3-IP2 and 3.1.2-3-IP3 on cracking of ASME Code Class 1 piping and pressurizer components, in LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3 on cracking of ASME Code Class 1 SG components, the applicant has provided an acceptable basis for crediting the Water Chemistry Control Program – Primary and Secondary and the Inservice Inspection Program to manage cracking of the components under exposure to the reactor coolant. Based on the review, the staff finds that the applicant's AMRs for these components are acceptable because they are consistent with the recommended guidance in GALL1 AMR 1-68 and in GALL AMR IV.C2-2, IV.C2-5, IV.C2-20 or IV.D1-1. Audit Item 357 is resolved.

With respect to the applicant's response to Audit Item 207 on aging management of cracking due to SCC of the pressurizer spray head couplings and locking bars, the staff concludes that the applicant has provided an acceptable basis for crediting the Water Chemistry Control Program – Primary and Secondary and the One-Time Inspection Program to manage cracking in the pressurizer spray head coupling and locking bars because the components are not categorized as ASME Code Class 1 components and because, consistent with the staff's guidance in GALL AMP XI.M32, "One-Time Inspection," the One Time Inspection Program will be used to verify that the Water Chemistry Control Program – Primary and Secondary is effective in managing cracking of these components as a result of SCC. Audit Item 207 is resolved.

3.1.2.1.4 Cracking Due to Stress Corrosion Cracking and Loss of Material Due to Crevice Corrosion and Fretting

LRA Table 3.1.1, Line Item 74 (LRA AMR 3.1.1-74) addresses cracking due to SCC and loss of material due to crevice corrosion and fretting in chrome plated steel, stainless steel, nickel alloy SG anti-vibration bars exposed to secondary feedwater/steam.

GALL AMR IV.D1-15 pertains to the management of loss of material due to crevice corrosion or fretting in carbon steel SG antivibration bars in PWRs with recirculating SGs. In this AMR, the staff recommends that programs corresponding to GALL AMP XI.M2, "Water Chemistry," and GALL AMP XI.M19, "Steam Generator Tube Integrity," be credited for aging management of loss of material due to crevice corrosion or fretting in chrome plate steel, stainless steel, or nickel alloy component surfaces that are exposed to secondary treated water or steam environments (i.e., to FW or steam).

The staff noted that for anti-vibration bars and end caps, peripheral retaining rings, feedwater (FW) nozzle thermal sleeves, the applicant credited both its Water Chemistry Control Program – Primary and Secondary Program and its Steam Generator Integrity Program for aging management of loss of material in the component surfaces that are exposed to either a treated water or steam environment, which is consistent with the recommendations in GALL AMR IV.D1-15. SER Sections 3.0.3.2.17 and 3.0.3.2.14 document the staff's evaluation of the Water Chemistry Control Program – Primary and Secondary Program and the Steam Generator Integrity Program, respectively.

3.1.2.1.5 Wall Thinning Due to Flow-Accelerated Corrosion

LRA Table 3.1.1, Line Item 59 (LRA AMR 3.1.1-59) addresses wall thinning due to flow-accelerated corrosion in steel SG steam nozzle and safe end, feedwater nozzle and safe end, AFW nozzles and safe ends exposed to secondary feedwater/steam. AMR Item 59 in Table 1 of the GALL Report, Volume 1 (GALL1 AMR 1-59) is the AMR that corresponds to LRA AMR 3.1.1-59. For PWRs with recirculating SGs (like IP2 and IP3), AMR IV.D1-5 is the component specific AMR that derives from GALL1 AMR 1-59. In these AMRs, the staff recommends that an AMP corresponding to GALL AMP XI.M17, "Flow-Accelerated Corrosion," be credited to manage wall thinning in these components as a result of flow-accelerated corrosion.

In LRA AMR 3.1.1-59, the applicant stated that the SG steam outlet nozzle contains a nickel alloy flow restrictor and the SG feedwater (FW) nozzle contains a nickel alloy thermal sleeve that isolate the carbon steel nozzles from high fluid velocities. Based on these design features, the applicant concluded that these components are not susceptible to flow-accelerated corrosion. However, during the audit, the staff found that a small section of the SG FW nozzle next to the FW piping is exposed to FW flow and is, therefore, susceptible to flow-accelerated corrosion requiring aging management. The staff asked why the design features for these SG nozzles would be sufficient to mitigate the potential for flow-accelerated corrosion to initiate in the component surfaces that are exposed to the feedwater or steam environments (Audit Item 202). Specifically, the staff asked the applicant to explain: (1) why the flow restrictor for the nickel alloy SG steam outlet nozzle is considered to be sufficient for isolating the SG outlet nozzles and their safe-ends from a two-phase steam environment (i.e., steam with some water content in it), and (2) why the thermal sleeves for the SG FW and auxiliary feedwater (AFW) nozzles are considered to be sufficient for isolating these SG nozzles and their safe-end from the secondary treated water environment,

The applicant responded to Audit Item 202 in a letter dated December 18, 2007. With respect to the SG steam outlet nozzles, the applicant clarified that the flow restrictors for the SG outlet nozzles totally isolate the components from exposure to a two-phase steam environment. In addition, the applicant clarified that, even if the carbon steel nozzles were exposed to the steam environment, flow-accelerated corrosion would not be an aging mechanism of concern because the steam environment would be of a high quality (i.e., dry). In GALL AMP XI.M17, “Flow-Accelerated Corrosion,” the staff endorses EPRI Report NSAC-202, Revision 2 as an acceptable basis for identifying whether carbon steel or alloy steel materials are susceptible to flow-accelerated corrosion. In this document, the industry identifies that carbon steel or alloy steel materials with less than 0.75 percent chromium contents are susceptible to flow-accelerated corrosion if they are subjected to high velocity aqueous environments (i.e. high velocity water-based solutions) or high velocity water/steam environments (i.e. high velocity two-phased aqueous flow environments). The staff’s finds this to be an acceptable response because the steam environment coming off the SG steam dryers are essentially 99.9 percent dry steam and this environment does not have a sufficient water content to be considered a high velocity two-phase aqueous environment. As a result, the staff finds that the applicant has provided an acceptable basis for concluding that loss of material due to flow-accelerated corrosion is not an AERM in the SG steam outlet nozzles or their safe-ends. Audit Item 202 is resolved with respect to the SG steam outlet nozzles and the safe-ends.

With respect to the AFW nozzles, the applicant clarified, in a letter dated December 18, 2007, that the AFW system is not normally in service and that, as a result of this operational basis, loss of material due to flow-accelerated corrosion is not an AERM for the period of extended operation. The staff noted that the SRP-LR Section A.1.2.1, Item 7, provides the following discussion about using an operational consideration as a basis for identifying whether an aging effect is applicable to a specific component:

> The applicable aging effects to be considered for license renewal include those that could result from normal plant operation, including plant/system operating transients and plant shutdown. Specific aging effects from abnormal events need not be postulated for license renewal. However, if an abnormal event has occurred at a particular plant, its contribution to the aging effects on structures and components for license renewal should be considered for that plant. For example, if a resin intrusion has occurred in the reactor coolant system at a particular plant, the contribution of this resin intrusion event to aging should be considered for that plant.

For PWR designs, AFW systems are initiated only during anticipating operational transients that result in a SCRAM of the reactor, during postulated design basis accidents, or during initiations of the systems that are implemented to meet required technical specification (TS) surveillance requirements. Thus, the staff finds that the applicant's basis for concluding that loss of material due to flow-accelerated corrosion is not an AERM for the SG AFW nozzles is acceptable because it is in conformance with the position in SRP-LR Section A.1.2.1, Item 7, that specific aging effects from abnormal events need not be postulated for license renewal. Audit Item 202 is resolved with respect to the SG AFW nozzles.

With respect to the SG FW nozzles and safe-ends, the applicant clarified, in a letter dated December 18, 2007, that, upon further review, the design of the carbon steel SG FW nozzles includes a portion of the nozzles (next to the FW piping) that is exposed to the FW treated water environment. To address this issue, the applicant stated that the LRA would be amended to include new AMRs in LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3 on loss of material due to flow-accelerated corrosion for the SG FW nozzles that are exposed to treated water. In addition, in the AMRs consistent with the staff's aging management basis in GALL AMR IV.D2-7 (which provides equivalent aging management basis to the staff's aging management basis in GALL AMR IV.D1-5), the applicant will credit the Flow-Accelerated Corrosion Program with the management of this aging effect/aging mechanism.

The staff verified that the applicant made the applicable amendments of the LRA in the letter of December 18, 2007. The staff also verified that the applicant's amended AMR basis for managing loss of material due to flow-accelerated corrosion in the SG FW nozzle components is consistent with the staff's basis for managing loss of material due to flow-accelerated corrosion in SG FW nozzles, as given in either GALL AMR IV.D1-5 or GALL AMR IV.D2-7. Based on this amendment of the LRA, the staff finds the applicant has provided an acceptable basis for managing loss of material due to flow-accelerated corrosion in the IP2 and IP3 SG FW nozzles. This is because, consistent with the staff's aging management basis in GALL AMR IV.D1-5 or IV.D2-7, the applicant has identified that loss of material due to flow-accelerated corrosion is an AERM for the SG FW nozzles, and because the applicant has credited its Flow-Accelerated Corrosion Program to manage loss of material due flow-accelerated corrosion in these components. Audit Item 202 is resolved with respect to the SG FW nozzles.

3.1.2.1.6 Loss of Material Due to Erosion

LRA Table 3.1.1, Line Item 66 (LRA AMR 3.1.1-66) addresses loss of material due to erosion in steel steam generator secondary manways and handholds (cover only) exposed to air with leaking secondary-side water and/or steam. AMR Item 66 in Table 1 of the GALL Report, Volume 1 (GALL1 AMR 1-66), and GALL AMR IV.D2-5 recommend that an AMP corresponding to GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," be credited to manage loss of material in the secondary manways and handholds (cover only) of once-through SG designs.

The staff noted that in LRA AMR 3.1.1-66, the applicant stated that GALL1 AMR 1-66 was not used, since erosion at manways and handholes is the result of leaking joints that have not been corrected. The applicant clarified in the application that leaks at IP2 and IP3 are repaired as soon as practical, and that if damage due to erosion occurred, it would also be repaired. In Audit Item 206, the staff asked the applicant to provide further clarification on its basis for concluding that loss of material due to erosion is not an aging effect requiring management for the SG secondary manways and handhold.

By letter dated December 18, 2007, the applicant provided the following response to the staff's question:

> Erosion at manways and handholes results from abnormal conditions, that is, leakage. This mechanism can cause loss of material independent of the age of the components. Pressure leak tests are required by ASME Section XI, IWC. Because ISI of secondary components manages potential leaks, erosion of manways and handholes due to leakage is not an applicable aging effect.

The staff noted that the applicant used an argument that leakage past the bolted connections in the secondary SG manway and handhold covers is an abnormal event, and that because of this fact, loss of material due to erosion does not need to be identified as an AERM for these components. In Section A.1.2.1, Item 7 of the Appendix A of the SRP-LR (i.e., NUREG-1800, Revision 1), the staff takes the following position on whether correction of leakage from in-scope components can be used as a basis for concluding that a specific aging effect is not applicable and does not need to be managed:

> The applicable aging effects to be considered for license renewal include those that could result from normal plant operation, including plant/system operating transients and plant shutdown. Specific aging effects from abnormal events need not be postulated for license renewal. However, if an abnormal event has occurred at a particular plant, its contribution to the aging effects on structures and components for license renewal should be considered for that plant. For example, if a resin intrusion has occurred in the reactor coolant system at a particular plant, the contribution of this resin intrusion event to aging should be considered for that plant.
>
> [Design basis events] DBEs are abnormal events; they include: design basis pipe break, LOCA, and safe shutdown earthquake (SSE). Potential degradations resulting from DBEs are addressed, as appropriate, as part of the plant's CLB. There are other abnormal events which should be considered on a case-by-case basis. For example, abuse due to human activity is an abnormal event; aging effects from such abuse need not be postulated for license renewal. When a safety-significant piece of equipment is accidentally damaged by a licensee, the licensee is required to take immediate corrective action under existing procedures (see 10 CFR Part 50 Appendix B) to ensure functionality of the equipment. The equipment degradation is not due to aging; corrective action is not necessary solely for the period of extended operation.
>
> However, leakage from bolted connections should not be considered as abnormal events. Although bolted connections are not supposed to leak, experience shows that leaks do occur, and the leakage could cause corrosion. Thus, the aging effects from leakage of bolted connections should be evaluated for license renewal.

The staff noted that the applicant's response to Audit Item 206 was inconsistent with NRC's position in the SRP-LR that "leakage from bolted connections should not be considered as abnormal events," and that "the aging effects from leakage of bolted connections should be evaluated for license renewal." Thus, the staff would normally take the position that the applicant's position should be consistent with the staff's aging effect identification criterion in Section A.1.2.1, Item 7 of the Appendix A of the SRP-LR (i.e., NUREG-1800, Revision 1), and that leakage past the SG secondary manway bolting should be assessed for aging effects that could impact the integrity of the manway covers or their bolts. However, the staff did note that the applicant's response to Audit item 201 did indicate that the SA-193, Grade B7 bolting at IP2 and IP3 is included within the scope of the applicant's Bolting Integrity Program. Thus, the staff finds that by including the SA-193 Grade B7 bolting within the scope of the Bolting Integrity Program, the applicant will manage any loss of material, loss of preload, or potential cracking of the bolting that may occur during the period of extended operation. Thus, the staff was of the opinion that the applicant's response to Audit Item 201 was an extension of the applicant's response to Audit Item 206 and that any aging of the manway and handhole cover would be adequately managed because the applicant's implementation of its Bolting Integrity Program would be sufficient to manage any cracking, loss of material, or loss of preload that would occur in the SG secondary manway and handhole cover bolted connections. Audit Item 206 is resolved after taking into account that the information in the applicant's response to Audit Item 201, dated December 18, 2007.

3.1.2.1.7 Loss of Material in Nickel Alloy SG Secondary Side Handhold Cover RTD Bosses

In LRA Table 3.1.2-4-IP3, the applicant includes its AMR Item on management of loss of material in the IP3 SG secondary handhold cover RTD bosses, which are made from nickel alloy. The applicant aligned this AMR item to LRA AMR 3.1.1- 74 and to AMR Item IV.D1-15 in GALL Report, Volume 2 (GALL AMR Item IV.D1-15). For this AMR the applicant credited only the Water Chemistry Control Program – Primary and Secondary Program to manage loss of material in the component surfaces that are exposed to the secondary-side treated water environment (i.e., to FW).

GALL AMR IV.D1-15 pertains to the management of loss of material due to crevice corrosion or fretting in carbon steel SG antivibration bars in PWRs with recirculating SGs. In this AMR, the staff recommends that programs corresponding to GALL AMP XI.M2, "Water Chemistry," and GALL AMP XI.M19, "Steam Generator Tube Integrity," be credited for aging management of loss of material due to crevice corrosion or fretting in chrome plate steel, stainless steel, or nickel alloy component surfaces that are exposed to secondary treated water or steam environments (i.e., to FW or steam).

The staff noted, that for other IP3 AMRs that the applicant had aligned to GALL AMR Item IV.D1-15 (e.g., those on loss of material of the IP3 SG antivibration bars and peripheral aligning rings SG FW nozzle thermal sleeves), the applicant credited both its Water Chemistry Control Program – Primary and Secondary Program and its Steam Generator Integrity Program for aging management of loss of material in the component surfaces that are exposed to either a treated water or steam environment, which is consistent with the recommendations in GALL AMR IV.D1-15. The staff noted, however for the AMR on loss of material in the IP3 SG secondary handhold cover RTD bosses, the applicant only credited its Water Chemistry Control Program – Primary and Secondary Program to manage loss of material in the component surfaces that are exposed to the secondary-side treated water environment (i.e., FW). The staff noted that this was not consistent with the applicant's aging management basis for the SG antivibration bars and peripheral aligning rings or the SG FW nozzle thermal sleeves because the applicant did not credit its Steam Generator Integrity Program as an additional AMP for managing this aging effect. In Audit Item 209, the staff asked the applicant to provide its basis why the Steam Generator Integrity Program had not been credited for the SG secondary handhold cover RTD bosses.

By letter dated December 18, 2007, the applicant amended its LRA to add the Steam Generator Integrity Program as an additional program (i.e., in addition to the Water Chemistry Control Program – Primary and Secondary Program) to manage loss of material in both the IP3 SG secondary handhold cover RTD bosses and IP3 SG secondary handhold cover RTD well. The staff finds that the applicant's amended AMR for managing loss of material in both the IP3 SG secondary handhold cover RTD bosses and IP3 SG secondary handhold cover RTD well is acceptable because it is consistent with the staff recommendations in GALL AMR IV.D1-15 in that the applicant is crediting both its Water Chemistry Control Program – Primary and Secondary Program and its Steam Generator Integrity Program to manage loss of material in component surfaces that are exposed to the treated water environment.

The staff finds that the applicant's amended AMR for managing loss of material in both the IP3 SG secondary handhold cover RTD bosses and IP3 SG secondary handhold cover RTD well is acceptable because it is consistent with the staff's recommendations in GALL AMR IV.D1-15 that programs correspond to GALL AMP XI.M19, "Steam Generator Tubing Integrity" and GALL AMP XI.M2, "Water Chemistry," be credited to manage loss of material in chrome plated steel, stainless steel or nickel alloy SG component surfaces that are exposed to either a secondary treated water or steam environment. Audit Item 209 is resolved with respect to this AMR item.

3.1.2.1.8 Cracking in Stainless Steel SG Secondary Side Handhold RTD Wells

In LRA Table 3.1.2-4-IP3, the applicant includes its AMR item on management of cracking in the IP3 SG secondary side handhold RTD well, which is made from austenitic stainless steel. The applicant aligned this to LRA AMR 3.1.1-74 and to AMR Item IV.D1-14 in GALL Report, Volume 2 (GALL AMR Item IV.D1-14). In this AMR, the applicant credited only its Water Chemistry Control Program – Primary and Secondary Program to manage cracking in the stainless steel component surfaces that are exposed to secondary treated water.

GALL AMR IV.D1-14 pertains to the management of cracking in chrome plated steel, stainless steel, or nickel alloy SG antivibration bars in PWRs with recirculating SGs. In this AMR, the staff recommends that programs corresponding to GALL AMP XI.M2, "Water Chemistry," and GALL AMP XI.M19, "Steam Generator Tube Integrity," be credited for aging management of cracking due to SCC in chrome plated steel, stainless steel, or nickel alloy component surfaces that are exposed to secondary treated water or steam environments.

The staff noted, that for other IP3 AMRs that the applicant had aligned to GALL AMR Item IV.D1-14 (e.g., those on cracking of the IP3 SG flow restrictor and flow baffle distribution plate), the applicant credited both its Water Chemistry Control Program – Primary and Secondary Program and its Steam Generator Integrity Program for aging management of cracking in the component surfaces that are exposed to either treated water or steam, which is consistent with the recommendations in GALL AMR IV.D1-14. In contrast, the staff noted that for management of cracking in the IP3 SG secondary side handhold RTD well, the applicant credited only its Water Chemistry Control Program – Primary and Secondary Program to manage cracking in the stainless steel component surfaces that are exposed to treated water. In Audit Item 210, the staff asked the applicant why the Steam Generator Integrity Program had not been credited as an additional program to manage cracking in the IP3 SG secondary side handhold RTD well.

The applicant responded to Audit Item 209 in a letter dated December 18, 2007. In this letter the applicant amended its LRA to add the Steam Generator Integrity Program as an additional program (i.e., in addition to the Water Chemistry Control Program – Primary and Secondary Program) to manage cracking in the IP3 SG secondary handhold cover RTD well. The staff finds that the applicant's amended AMR for managing cracking in the IP3 SG secondary handhold cover RTD well is acceptable because it is consistent with the staff's recommendations in GALL AMR IV.D1-14 that programs correspond to GALL AMP XI.M19, "Steam Generator Tubing Integrity" and GALL AMP XI.M2, "Water Chemistry," be credited to manage cracking in chrome plated steel, stainless steel or nickel alloy SG component surfaces that are exposed to either a secondary treated water or steam environment. Audit Item 209 is resolved with respect to this AMR item.

3.1.2.1.9 Conclusion for AMRs Consistent with the GALL Report

The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2 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 reactor vessel, internals, and reactor coolant system 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
- loss of fracture toughness due to neutron irradiation embrittlement and void swelling
- cracking due to SCC
- cracking due to cyclic loading
- loss of preload due to stress relaxation
- loss of material due to erosion
- cracking due to flow-induced vibration
- cracking due to SCC and irradiation-assisted SCC
- cracking due to PWSCC
- wall thinning due to flow-accelerated corrosion
- changes in dimensions due to void swelling
- cracking due to SCC and PWSCC
- cracking due to SCC, PWSCC, and irradiation-assisted 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 report and for which the report recommends further evaluation, the staff audited and reviewed the applicant's evaluation. The staff determined whether the applicant adequately addressed the issues for which further evaluation is recommended. The staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.1.2.2. The staff's review of the applicant's further evaluation follows.

3.1.2.2.1 Cumulative Fatigue Damage

LRA Section 3.1.2.2.1 stated that fatigue is a TLAA, as defined in 10 CFR 54.3. Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(c)(1). SER Section 4.3 documents the staff's review of the applicant's evaluation of this TLAA. However, since many of the RCS components do not have fatigue usage factor calculations of their original design, Entergy will manage them using aging management programs in accordance with 10CFR54.21(c)(iii). Therefore, the staff assessments of these components are discussed below.

LRA Section 3.1.2.2.1 stated that, with the exception of the pressurizer support skirts, evaluation of the fatigue TLAA for the Class 1 portions of the reactor coolant pressure boundary piping and components, including those for interconnecting systems, is discussed in LRA Section 4.3.1. No fatigue analysis was required for the pressurizer support skirts. Cracking, including cracking due to fatigue, will be managed by the Inservice Inspection Program for the pressurizer support skirts.

SRP-LR Section 3.1.2.2.1 states that "[f]atigue is a time-limited aging analysis (TLAA) as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.3, 'Metal Fatigue Analysis,' of this SRP-LR." For Westinghouse designed PWRs with recirculating SGs, SRP-LR Section 3.1.2.2.1 invokes the AMRs on "cumulative fatigue damage" in AMR Items 1, 5, 6, 7, 8, 9, and 10 of Table 1 to the GALL Report, Volume 1 and the plant-specific AMRs on "cumulative fatigue damage" for reactor vessel (RV) components, reactor vessel internal (RVI) components, RCS piping and pressurizer components, and SGs in Sections IV.A2, IV.B2, IVC2, and IV.D1 of the GALL Report Volume 1. In these AMRs, the GALL Report recommends that the PWR applicants credit their TLAAs on metal fatigue for management of "cumulative fatigue damage" in these components.

The staff noted that instead of referring to the aging effect term "cumulative fatigue damage," the applicant's applicable AMRs on metal fatigue refer to the aging effect as "cracking – fatigue." The staff finds the slight difference in terminology to be acceptable because the coalescence of any fatigue damage in the microstructure will manifest itself in the form of a fatigue crack. Based on this assessment, the staff verified that the applicant's AMRs on management "cracking –fatigue" in the LRA are those that correspond to the staff's AMRs in the GALL report which refer to management of "cumulative fatigue damage."

The staff verified that the applicant credits its TLAA on metal fatigue, as given in LRA Section 4.3 and its subsections, for management of "cumulative fatigue damage" in the IP ASME Code Class 1 RV components, RVI components, RCS piping, piping components, and piping elements, and pressurizer components, with the exception of metal fatigue analyses for the pressurizer support skirts.

SRP-LR Table 3.1.1, Item 7 addresses the TLAA for cumulative fatigue damage in steel and stainless steel RV support skirts and attachment welds in the RCS. The staff noted from LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3 line items that the reactor vessels are not supported by RV support skirts, but instead use support pads that are welded to the underside of the primary inlet and outlet nozzles as the means of RV support. By letter dated December 18, 2007, the applicant responded to Audit Item 191A, and clarified that the support pads for the reactor vessel are part of the inlet and outlet nozzle forgings and are evaluated as part of those nozzles. The staff verified that that the metal fatigue analyses of the RV components, as discussed in LRA Section 4.3.1.1, include cumulative usage factor inputs for the RV inlet and outlet nozzles. Therefore, the staff finds that the management of the RV support pads is consistent with the guidance in SRP-LR Section 3.1.2.2.1. The staff also finds that the LRA does not need to include any AMR item on management of cumulative fatigue damage in RV support skirts because the IP designs do not use this type of component for RV support.

The staff noted that in the response to Audit Item 191A, Entergy confirmed that the CLB does not include any fatigue analysis for the pressurizer support skirts. Based on this review, the staff finds that the LRA does not need to include any AMR corresponding to GALL AMR IV.C2-10 on "cumulative fatigue damage" of pressurizer integral supports but the CLB does not include any fatigue analyses for these components at IP. Instead, the staff noted that the applicant is crediting its Inservice Inspection Program to manage cracking of these components, including the applicant's aging effect of "cracking – fatigue." The staff finds this to be an acceptable alternative because it is in conformance with the staff's AMR on cracking of pressurizer integral supports, as given in GALL AMR IV.C2-16.

LRA Tables 3.1.2-1-IP2, 3.1.2-1-IP3, 3.1.2-3-IP2, 3.1.2-3-IP3, 3.1.2-4-IP2, and 3.1.2-4-IP3 all indicate a TLAA line item referring to Table 3.1.1-7 for the RCS components. The LRA Table 2 line items associated with this TLAA do not include the support skirts and/or attachment welds for SGs and reactor coolant pumps (RCP). In Audit Item 191c, the staff requested IPNG to clarify how "cracking - fatigue" of the RCP and SG supports is managed. In its response, dated December 18, 2007, Entergy stated that the SGs are supported by pads attached to the primary channel heads and that the AMRs in LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3 for the primary channel heads (which include the integral pads) do not include any AMRs on "cracking –fatigue" because the CLB does not include any fatigue analyses for these components. The staff verified that the CLB does not include any fatigue analyses for the SG primary channel head support pads. Based on this determination, the staff finds that the TLAA on metal fatigue of the Class 1 RCS piping components does not need to include any metal fatigue analysis for the SG primary channel head support pads because the CLB does not include any metal fatigue analysis for these components, and thus, the components are not subject to a metal fatigue TLAA under the TLAA definition criteria that are provided in 10 CFR 54.3.

The staff also noted that in the IP design, the RCPs are supported by feet that are directly attached to the pump casings and that these components are within the scope of the AMRs in LRA Tables 3.1.2-3-IP2 and 3.1.2-3-IP3. The staff verified that the CLB for IP does not include any metal fatigue analyses for these RCP supports. Based on this determination, the staff finds that the TLAA on metal fatigue of the Class 1 RCS piping components does not need to include any metal fatigue analysis for the RCP supports (i.e., feet) because the IP CLB does not include any metal fatigue analysis for these components and thus, the components are not subject to a metal fatigue TLAA under the TLAA definition criteria of 10 CFR 54.3.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.1 criteria. For those line items that apply to LRA Section 3.1.2.2.1, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.2 Loss of Material Due to General, Pitting, and Crevice Corrosion

The staff reviewed LRA Section 3.1.2.2.2 against the criteria in SRP-LR Section 3.1.2.2.2.

(1) LRA Section 3.1.2.2.2 addresses loss of material due to general, pitting, and crevice corrosion in steam generator steel components exposed to secondary feedwater and steam, stating that the Water Chemistry Control - Primary and Secondary Program manages this aging effect. The One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control - Primary and Secondary Program by inspection of a representative sample of components crediting this program, including those in areas of stagnant flow.

SRP-LR Section 3.1.2.2.2 states that loss of material due to general, pitting, and crevice corrosion may occur in the steel PWR SG shell assembly exposed to secondary feedwater and steam. Loss of material due to general, pitting, and crevice corrosion also may occur in the steel top head enclosure (without cladding) top head nozzles (vent, top head spray or reactor core isolation cooling, and spare) exposed to reactor coolant. The existing program controls reactor water chemistry to mitigate corrosion. However, control of water chemistry does not preclude loss of material due to pitting and crevice corrosion at locations with stagnant flow conditions. Therefore, the effectiveness of water chemistry control programs should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to verify the effectiveness of water chemistry control programs. A one-time inspection of selected components at susceptible locations is an acceptable method to determine whether an aging effect is occurring or is slowly progressing such that the component's intended functions will be maintained during the period of extended operation.

LRA Table 3.1-1, Item 11, which addresses loss of material due to general, pitting, and crevice corrosion in the steel top head enclosure (without cladding) top head nozzles (vent, top head spray or reactor core isolation cooling, and spare) exposed to reactor coolant, is identified as not applicable because it applies to boiling water reactors (BWRs) only. Because IP2 and IP3 are PWRs, the staff finds that this component/aging effect combination does not apply to IP.

The staff noted that the SGs at IP2 and IP3 are Westinghouse Model 44F replacement SGs. The staff also noted that in LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3, the applicant aligned the following AMR line items for its SG components to LRA Table 1 AMR Item 3.1.1-12 and to GALL AMR IV.D2-8 (R-224) for once-through SG secondary side components: secondary side of the tubesheets, feedwater nozzles, secondary manways and manway covers, secondary handholds and handhold covers, secondary SG shell drain connection, secondary side instrument connections and SG blowdown piping, The staff noted that in the applicant AMRs for these components, the applicant credited its Water Chemistry Control Program – Primary and Secondary to manage loss of material in the component surfaces that are exposed secondary treated water or steam. The staff also noted that the applicant did not credit its One-Time Inspection Program or apply LRA AMR plant-specific Note 104,which states that the One-Time Inspection Program will be used to verify the effectiveness of the Water Chemistry Control Program – Primary and Secondary in managing loss of material in these components. In Audit Item 192, the staff asked the applicant to justify why the AMRs on loss of material in the secondary side of these carbon steel SG components did not credit LRA AMP B.1.27, One-Time Inspection Program, to verify the effectiveness of the Water Chemistry Control Program – Primary and Secondary in managing loss of material in the secondary side surfaces of these carbon steel SG components.

By letter dated December 18, 2007, the applicant clarified that the One-Time Inspection Program is credited with verifying the effectiveness of Water Chemistry Control Program – Primary and Secondary in managing loss of material in these secondary side SG components. The applicant stated that it would amend the AMR items in LRA Table 3.1.2-4-IP2 and 3.1.2-4-IP3 on loss of material in secondary side SG components referencing LRA Table 1 Item 3.1.1-12 and GALL AMR Item IV.D2-8 (R-224) to add plant-specific AMR Note 104, which credits a one-time inspection for verification of the effectiveness of the Water Chemistry Control Program – Primary and Secondary in managing this aging effect.

The staff verified that, in its letter of December 18, 2007, the applicant amended the applicable AMRs for the secondary side SG tubesheets, feedwater nozzles, manways and manway covers, handholds and handhold covers, shell drain connections, instrument connections, and blowdown piping to add LRA AMR Note 104 and to credit in One-Time Inspection Program for verification of the effectiveness of the Water Chemistry Control Program – Primary and Secondary in managing loss of material due to pitting and crevice corrosion in the secondary side component surfaces that are exposed to treated water. The staff finds that the amended AMRs are acceptable because the AMPs credited for aging management are consistent with the staff's aging management position that is recommended in SRP-LR Section 3.1.2.2.2, Item (1) and in the GALL AMRs that are based on this SRP-LR Section.

(2) LRA Section 3.1.2.2.2 addresses loss of material due to general, crevice, and pitting corrosion in BWR isolation condenser components exposed to reactor coolant, stating that this aging effect is not applicable to IP, which are PWRs.

SRP-LR Section 3.1.2.2.2 states that loss of material due to pitting and crevice corrosion may occur in stainless steel BWR isolation condenser components exposed to reactor coolant. Loss of material due to general, pitting, and crevice corrosion may occur in steel BWR isolation condenser components.

The staff finds that SRP-LR Section 3.1.2.2.2, Item (2) is not applicable to IP because IP2 and IP3 are PWRs, and the staff guidance in this SRP-LR section is only applicable to BWRs that are designed with isolation condensers.

(3) LRA Section 3.1.2.2.2 addresses loss of material due to general, crevice, and pitting corrosion in reactor vessel shells, heads, and welds; flanges; nozzles; penetrations; pressure housings; and safe ends, stating that this aging effect is not applicable to IP, which are PWRs.

SRP-LR Section 3.1.2.2.2 states that loss of material due to pitting and crevice corrosion may occur in stainless steel, nickel alloy, and steel with stainless steel or nickel alloy cladding flanges, nozzles, penetrations, pressure housings, safe ends, and vessel shells, heads, and welds exposed to reactor coolant. This SRP-LR Section invokes AMR 14 in Table 1 of the GALL Report, Volume 1 and the associated AMRs in the GALL Report, Volume 2 which are applicable to stainless steel, nickel alloy, and steel with stainless steel or nickel alloy cladding flanges, nozzles, penetrations, pressure housings, safe ends, and vessel shells, heads, and welds in BWR-designed reactors.

The staff finds that SRP-LR Section 3.1.2.2.2, Item (3) is not applicable to IP because IP2 and IP3 are PWRs, and the staff guidance in this SRP-LR section is only applicable to BWR-designed reactors.

(4) LRA Section 3.1.2.2.2 addresses loss of material due to general, pitting, and crevice corrosion in the steel steam generator shell and transition cone exposed to secondary feedwater and steam, stating that the Inservice Inspection and Water Chemistry Control – Primary and Secondary Programs manage this aging effect. IP steam generators have been replaced. The replacement generators, Model 44Fs, have no high-stress region at the shell to transition cone weld as described in NRC Information Notice (IN) 90-04 and, as such, require no additional inspection procedures.

SRP-LR Section 3.1.2.2.2 states that loss of material due to general, pitting, and crevice corrosion may occur in the steel PWR steam generator upper and lower shell and transition cone exposed to secondary feedwater and steam. The existing program controls chemistry to mitigate corrosion and inservice inspection (ISI) to detect loss of material. The extent and schedule of the existing steam generator inspections are designed to ensure that flaws cannot attain a depth sufficient to threaten the integrity of the welds; however, according to IN 90-04, the program may not be sufficient to detect pitting and crevice corrosion, if general and pitting corrosion of the shell is known to occur. The GALL Report recommends augmented inspection to manage this aging effect. Furthermore, the GALL Report clarifies that this issue is limited to Westinghouse Model 44 and 51 steam generators with a high-stress region at the shell to transition cone weld.

The staff noted that the staff's guidance in SRP-LR Section 3.1.2.2.2, Item (4) is applicable to only to Westinghouse SG Models 44 and 51 with high stress regions at the shell to transition cone weld. The IP SGs were replaced with Westinghouse model 44F units which do not have this transition weld susceptible to pitting and crevice corrosion. Therefore, the staff determined that the IP SGs do not require any additional augmented inspections of the SG shell-to-transition cone regions as recommended in SRP-LR Section 3.1.2.2.2 or the GALL Report for Westinghouse Model 44 or 51 SG designs.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.2 criteria. For those line items that apply to LRA Section 3.1.2.2.2, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.3 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement

The staff reviewed LRA Section 3.1.2.2.3 against the criteria in SRP-LR Section 3.1.2.2.3.

(1) LRA Section 3.1.2.2.3 states that neutron irradiation embrittlement is a TLAA, as defined in 10 CFR 54.3. Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(c)(1). SER Section 4.2 documents the staff's review of the applicant's evaluation of this TLAA.

(2) LRA Section 3.1.2.2.3 addresses loss of fracture toughness due to neutron irradiation embrittlement, stating that the Reactor Vessel Surveillance Program manages reduction in fracture toughness due to neutron embrittlement of RV beltline materials to maintain the pressure boundary function of the reactor pressure vessel for the period of extended operation. The program evaluates radiation damage by pre- and post-irradiation testing of Charpy V-notch and tensile specimens from the most limiting plate in the reactor vessel core region with reports submitted as required by 10 CFR Part 50, Appendix H.

    SRP-LR Section 3.1.2.2.3 states that loss of fracture toughness due to neutron irradiation embrittlement may occur in BWR and PWR reactor vessel beltline shell, nozzle, and welds exposed to reactor coolant and neutron flux. A reactor vessel materials surveillance program monitors neutron irradiation embrittlement of the reactor vessel. Reactor vessel surveillance programs are plant-specific, depending on matters such as the composition of limiting materials, availability of surveillance capsules, and projected fluence levels. In accordance with 10 CFR Part 50, Appendix H, an applicant is required to submit its proposed withdrawal schedule for approval prior to implementation. Untested capsules placed in storage must be maintained for future insertion. Thus, further staff evaluation is required for license renewal. Specific recommendations for an acceptable AMP are provided in GALL Report Chapter XI, Section M31.

    The staff reviewed the IP Reactor Vessel Surveillance Program that manages reduction in fracture toughness due to neutron embrittlement of the vessel beltline region material, excluding the vessel nozzles. During an onsite audit, the staff identified a statement in WCAP-16212, "Entergy Nuclear Operations, Incorporated, Indian Point Nuclear Generating Unit No. 3, Stretch Power Uprate, License Amendment Request Package," June 2004, that indicated that the typical fluence at the nozzle of an IP vintage vessel is about 0.6 percent of the peak vessel fluence. Based on this statement, the staff was concerned that the neutron fluence for the nozzle shell course could exceed $1x10^{17}$ n/cm^2. Therefore, via a telephone conference call, the staff requested that the applicant perform a neutron fluence evaluation for the components in the nozzle shell course. SER Section 4.2.2.2 documents the staff's evaluation of the applicant's analysis.

Based on the reviews discussed in the paragraphs above, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.3 criteria. For those line items that apply to LRA Section 3.1.2.2.3, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.4 Cracking Due to Stress Corrosion Cracking and Intergranular Stress Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.4 against the criteria in SRP-LR Section 3.1.2.2.4.

(1) LRA Section 3.1.2.2.4 addresses cracking due to SCC and intergranular SCC (IGSCC) in BWR vessel leak detection lines, stating that this aging effect is not applicable to IP, which are PWRs.

    SRP-LR Section 3.1.2.2.4 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 IP2 and IP3 because IP2 and IP3 are PWRs, and the staff guidance in this SRP-LR section is only applicable to BWR-designed reactors.

(2) LRA Section 3.1.2.2.4 addresses cracking due to SCC and IGSCC in BWR isolation condenser components, stating that this aging effect is not applicable to IP, which are PWRs.

    SRP-LR Section 3.1.2.2.4 states that cracking due to SCC and IGSCC may occur in stainless steel BWR isolation condenser components exposed to reactor coolant.

    The staff finds that SRP-LR Section 3.1.2.2.4, Item (2) is not applicable to IP2 and IP3 because IP2 and IP3 are PWRs, and the staff guidance in this SRP-LR section is only applicable to BWR-designed reactors that are designed with isolation condensers.

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.1.2.2.4, Items (1) and (2) do not apply to IP2 and IP3 because the guidance is applicable to BWR-designed reactors and because IP2 and IP3 are PWRs.

3.1.2.2.5 Crack Growth Due to Cyclic Loading

The staff reviewed LRA Section 3.1.2.2.5 against the criteria in SRP-LR Section 3.1.2.2.5.

LRA Section 3.1.2.2.5 states that growth of intergranular separations (underclad cracks) in the heat-affected zone under austenitic steel cladding is not an applicable aging effect because the IP vessel shells are not composed of SA 508-Cl 2 forgings with stainless steel cladding deposited with a high heat input welding process.

SRP-LR Section 3.1.2.2.5 states that crack growth due to cyclic loading could occur in reactor vessel shell forgings clad with stainless steel using a high-heat-input welding process. Growth of intergranular separations (underclad cracks) in the heat affected zone under austenitic stainless steel cladding is a TLAA to be evaluated for the period of extended operation for all SA 508-Cl 2 forgings where the cladding was deposited with a high heat input welding process. The methodology for evaluating the underclad flaw should be consistent with the current well-established flaw evaluation procedure and criterion in the ASME Section XI Code. See the SRP-LR, Section 4.7, "Other Plant-Specific Time-Limited Aging Analysis," for generic guidance for meeting the requirements of 10 CFR 54.21(c).

The staff confirmed that, in Table 5.1-2 of WCAP-16157-NP, Westinghouse Electric Company reports that the IP2 RV shells are fabricated from SA-533 alloy steel plate materials, and in WCAP-16251-NP, Revision 0, Westinghouse Electric Company reports that the IP3 RV shells are fabricated from SA-302 Grade B alloy steel plate materials. Based on this review, the staff finds that the applicant has provided an acceptable basis for concluding that the staff's guidance on RV underclad cracking, as given in SRP-LR Section 3.1.2.2.5, is not applicable to IP because the IP2 and IP3 RV shells are not fabricated from SA 508, Class 2 or Class 2 alloy steel forging materials.

3.1.2.2.6 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement and Void Swelling

The staff reviewed LRA Section 3.1.2.2.6 against the criteria in SRP-LR Section 3.1.2.2.6.

LRA Section 3.1.2.2.6 addresses loss of fracture toughness due to neutron irradiation embrittlement and change in dimensions (void swelling) that could occur in stainless steel and nickel alloy RVI components exposed to reactor coolant and neutron flux, stating that to manage loss of fracture toughness in such components, Entergy will (1) participate in industry programs for investigating and managing aging effects on reactor internals, (2) evaluate and implement the results of the industry programs pertinent to reactor internals, and (3) upon completion of these programs but not less than 24 months before the period of extended operation, submit an inspection plan for RVI to the staff for review and approval. This commitment is in the UFSAR Supplement, LRA Appendix A, Sections A.2.1.41 and A.3.1.41.

SRP-LR Section 3.1.2.2.6 states that "loss of fracture toughness due to neutron irradiation embrittlement and void swelling may occur in stainless steel and nickel alloy reactor vessel internals components exposed to reactor coolant and neutron flux. The GALL Report recommends no further AMR if the applicant commits in the FSAR supplement (1) to participate in industry programs for investigating and managing aging effects on reactor internals, (2) to evaluate and implement the results of the industry programs as applicable to the reactor internals, and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, to submit an inspection plan for reactor internals to the staff for review and approval."

For Westinghouse-designed reactor vessel internals, SRP-LR Section 3.1.2.2.6 refers to the staff's guidance in AMR 22 of Table 1 to the GALL Report, Volume 1, and in GALL AMRs IV.B2-3, IV.B2-6, IV.B2-9, IV.B2-17, IV.B2-18, and IV.B2-22. These AMRs are applicable to the management of loss of fracture toughness due to neutron irradiation embrittlement and/or void swelling in Westinghouse-designed RVI core baffle/former assembly plates; core baffle/former assembly bolts and screws; core barrel (CB), CB flange, CB outlet nozzles, and thermal shield; lower internals assembly fuel alignment pins, lower support plate column bolts, and clevis insert bolts; lower internals assembly core plate; and lower internals assembly – lower support forging or castings and lower support columns.

The commitment that is recommended by the staff includes a provision for PWR applicant's to submit an inspection plan for their RVI components that is based on the industry's augmented inspection program recommendations for PWR RVI components to the NRC for review and approval at least two years prior to entering the period of extended operation. The staff verified that LRA Tables 3.1.2-2-IP2 and 3.1.2-2-IP3 include all of the appropriate AMRs on loss of fracture toughness due neutron irradiation embrittlement and/or void swelling for the various IP2 and IP3 RVI components

The staff verified that Entergy has made the applicable commitment for IP2 and IP3 in Commitment 30, which was provided in Entergy letter dated March 24, 2008, and included in UFSAR Supplements A.2.1.41 and A.3.1.41 for the IP2 PWR Vessel Internals Program and the IP3 PWR Vessel Internals Program, respectively.

Thus, based on this review, the staff finds that the applicant has provided an acceptable basis for using Commitment 30 as its basis for aging management of loss of fracture toughness due to neutron irradiation embrittlement and/or void swelling in these IP2 and IP3 RVI components. The staff confirmed that Entergy has committed to participate in industry programs for investigating and managing aging effects on IP2 and IP3 RVI components in the UFSAR Supplement Sections A.2.1.41 and A.3.1.41, and therefore, the staff finds this acceptable.

Based on the applicant's commitment (Commitment 30),,the staff concludes that the applicant meets SRP-LR Section 3.1.2.2.6 criteria. For those line items that apply to LRA Section 3.1.2.2.6, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.7 Cracking Due to Stress Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.7 against the criteria in SRP-LR Section 3.1.2.2.7.

(1) LRA Section 3.1.2.2.7 addresses cracking due to SCC in the stainless steel bottom-mounted instrument (BMI) guide tube components exposed to reactor coolant, stating that the Inservice Inspection and Water Chemistry Control - Primary and Secondary Programs manages this aging effect by minimizing contaminants which promote SCC. The Inservice Inspection Program provides periodic pressure testing of these components.

SRP-LR Section 3.1.2.2.7, Item (1) states that cracking due to SCC may occur in the PWR stainless steel reactor vessel flange leak detection lines and BMI guide tubes exposed to reactor coolant. The GALL Report recommends that a plant-specific AMP be evaluated to ensure that this aging effect is adequately managed.

The staff verified that in LRA Table 3.1.2-1-IP2 and 3.1.2-1-IP3, the applicant credits its Water Chemistry Control – Primary and Secondary Program and Inservice Inspection Program to manage cracking in stainless steel BMI guide tube components, including the BMI guide tubes, BMI seal tables and BMI flux thimble tube bullet plugs, which are ASME Code Class 1 components. The staff also verified that the applicant's Inservice Inspection Program credits periodic ISI inspections and pressure testing ensures that the cracking of these components are not occurring and the water chemistry program manages the contaminants that are detrimental to SCC in stainless steel will be controlled by the applicant. The staff verified that, in GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD," the staff endorses inservice inspection programs as acceptable condition monitoring AMPs for managing the aging effects (including cracking) that are applicable ASME Code Class components. The staff verified that, in GALL AMP XI.M2 “Water Chemistry,” the staff endorses water chemistry control programs as acceptable preventive/mitigative AMPs for controlling the water impurities that may induce aging effects (including cracking) in plant components (included ASME Code Class components) that are exposed to water-based coolants (i.e., treated water-type environments).

Based on this review, the staff finds that the applicant has provided an acceptable basis for crediting of the Inservice Inspection Program and the Water Chemistry Control Program – Primary and Secondary to manage cracking in these stainless steel BMI components because it conforms to the staff’s recommendation that a plant-specific AMP or AMPs be evaluated and credited for aging management of cracking in the components, and because the crediting of these program is consistent with the bases in GALL AMP XI.M1 and XI.M2 for ASME Code Class components.

With regard to RV flange leak detection lines, the staff noted that the applicant identified that the RV flange leakage detection lines are composed of nickel alloy. As a result of this fabrication material, the AMR items in LRA Table 3.1.2-1-IP2 and 3.1.2-1-IP3 for the RV flange leakage detection lines are aligned to LRA Section 3.1.2.2.13, AMR Item 31 in LRA Table 3.1.1, and GALL IV.C2-13 for nickel alloy ASME Code Class 1 piping less than 4-inch NPS. The staff evaluates the applicant’s AMRs on management of cracking in the nickel alloy RV flange leakage detection lines in SER Section 3.1.2.2.13.

(2) LRA Section 3.1.2.2.7 addresses cracking due to SCC in CASS reactor coolant system piping, piping components, and piping elements exposed to reactor coolant, stating that the Water Chemistry Control - Primary and Secondary and Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) programs manage this aging effect by (a) determining the susceptibility of CASS components to thermal aging embrittlement based on casting method, molybdenum content, and percent ferrite, and (b) accomplishing aging management for potentially susceptible components through either enhanced volumetric examination or plant- or component-specific flaw tolerance evaluation. The Inservice Inspection Program supplements these programs for some components.

SRP-LR Section 3.1.2.2.7, Item (2) states that cracking due to SCC may occur in Class 1 PWR CASS reactor coolant system piping, piping components, and piping elements exposed to reactor coolant. The existing program controls water chemistry to mitigate SCC. However SCC may occur in CASS components that do not meet the NUREG-0313 guidelines with regard to ferrite and carbon content. The GALL Report recommends further evaluation of a plant-specific program for these components to ensure this aging effect is adequately managed.

The staff noted that in LRA Tables 3.1.2-3-IP2 and 3.1.2-3-IP3, the applicant included the following AMRs on cracking of CASS RCS piping, piping components, and piping elements that aligned to SRP-LR Section 3.1.2.2.7, Item (2) and the staff’s guidance in GALL AMR IV.C2-3:

- Class 1 RCS piping elements made from CASS, including ASME Code Class 1 CASS elbows, flange components, scoops and tees
- The CASS pressurizer spray head, which in not categorized as an ASME Code Class component

For the ASME Code Class 1 CASS elbows, flange components, scoops and tees, the staff verified that the applicant identified the components as exceeding the NUREG-0313 acceptance criteria for cracking, and that the applicant's AMR credited a combination of the Water Chemistry Program – Primary and Secondary, the Inservice Inspection Program, and Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for management of cracking due to SCC in the component surfaces that are exposed to the reactor coolant. In contrast, for the CASS pressurizer spray head, the staff noted that the applicant only credited the Water Chemistry Program – Primary and Secondary and Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for management of this aging effect.

The staff verified that the applicant's Water Chemistry Program – Primary and Secondary is credited as an preventive and mitigative-based AMP for managing aging effects, including SCC, on metallic components from corrosion. The AMP is consistent with the staff's recommended program element criteria in GALL AMP XI.M2, "Water Chemistry." Based on this review, the staff finds that the applicant's crediting of the Water Chemistry Program – Primary and Secondary for the ASME Code Class 1 CASS elbows, flange components, scoops and tees, and for the non-ASME Code Class CASS pressurizer spray head, is consistent with the staff recommended position in SRP-LR Section 3.1.2.2.7, Item 2 and in GALL AMR IV.C2-3, and is acceptable. The staff's evaluation of the Water Chemistry Program – Primary and Secondary is given in SER Section 3.0.3.2.17. The staff's evaluation of this program includes its basis for accepting that the Water Chemistry Program – Primary and Secondary, when enhanced, is an acceptable program for preventing or mitigating the aging effects that are applicable to metallic components as a result of corrosion. The staff's evaluation includes the basis for accepting this program for the management of cracking in these CASS components.

The staff noted that the applicant's Inservice Inspection Program (described in LRA Section B.1.18) is credited, in part, as an acceptable plant-specific condition monitoring program for the management of cracking in ASME Code Class 1 components, including ASME Code Class 1 CASS components. However, the staff noted that the inspections credited under this program might be either ultrasonic test (UT) examinations or enhanced VT-1 visual examinations. The staff sought additional clarification on how a UT method for CASS material would be capable of differentiating between a UT reflector that results from a actual flaw indication in the material as opposed to a UT reflector that results as a background noise signal from the complexity of the CASS microstructure or the complexity of the component geometry.

By letter dated December 30, 2008, the staff issued RAI 3.1.2.2.7.2-1, Part A, and asked the applicant to clarify how current state of the art UT methods, as implemented through the Inservice Inspection Program or other programs, would be adequate to detect cracks in CASS materials, or else to credit an alternative non-destructive inspection technique for the detection of cracking in the CASS components at IP if the current state-of-the-art UT techniques are incapable of detecting cracks in the CASS materials. This was identified as Open Item 3.1.2.2.7.2-1, Part A.

The applicant responded to RAI 3.1.2.2.7.2-1, Part A in a letter dated January 27, 2009. In this response, the applicant stated that current volumetric examination methods, (including UT) are not currently reliable for the detection of cracking in CASS materials and therefore are not credited for aging management of cracking in the CASS components, including the CASS pressurizer spray heads. Thus, the staff noted that the applicant is currently relying on enhanced VT-1 visual examination methods to manage cracking in the CASS pressurizer spray heads. The staff finds this to be acceptable because current UT technology methods are currently unable to differentiate between UT reflections that result from actual flaw indications in the CASS material and those UT reflections that result from a background noise signal due to the complexity of the CASS microstructure. In addition, ASME Code, Section XI lists VT-1 visual examination methods as acceptable examination techniques for the detection of cracking. RAI 3.1.2.2.7.2-1, Part A is resolved and Open Item 3.1.2.2.7.2-1, Part A is closed with respect to the inspection techniques that are credited to manage cracking in the CASS pressurizer spray heads.

The staff also noted that the applicant's Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program (LRA Section B.1.37) was credited for: (1) evaluation of thermal aging embrittlement in both the Code Class 1 CASS elbows, flanges, tees, and scoops, and in the non-ASME Code Class CASS pressurizer spray head, and (2) detection of cracking in the non-ASME Code Class CASS pressurizer spray head. The staff verified that the applicant's Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program is credited as an acceptable condition monitoring program for the management of reduction of fracture toughness as a result of thermal aging in CASS components. The staff also verified that this program has been identified as a new AMP that is consistent with the staff's recommended program element criteria in GALL AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)."

The staff also noted that the applicant's program includes a flaw evaluation methodology for CASS components that are susceptible to thermal aging embrittlement. This AMP may propose UT or enhanced VT-1 visual examinations as an indirect basis for managing loss/reduction of fracture toughness as a result of thermal aging. However, the staff noted that the applicant's program is not specifically credited for the management of cracking in CASS components. Thus, while the applicant's Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program could be used as an acceptable basis for meeting the staff's "flaw evaluation methodology for CASS components that are susceptible to thermal aging embrittlement" criterion in GALL AMR IV.C2-3, the staff noted that the program may not be valid to manage cracking in these components because the aging effect addressed by the corresponding program in GALL AMP XI.M12 is limited to management of loss/reduction of fracture toughness in CASS components.

By letter dated December 30, 2008, the staff issued RAI 3.1.2.2.7.2-1, Part B, and asked the applicant to justify its basis crediting AMP B.1.37, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program, to manage and detect for cracking in the CASS pressurizer spray heads at IP2 and IP3; GALL AMP XI.M12 only credits this type of program for management of reduction or fracture toughness in components made from CASS and the program may not actually be performing inspections of this component (i.e., the program has the option only to do the flaw tolerance evaluation without implementation of either a UT or EVT-1 examination). This was identified as Open Item 3.1.2.2.7.2-1, Part B.

The applicant responded to RAI 3.1.2.2.7.2-1, Part A in a letter dated January 27, 2009. In this response, the applicant stated that the Water Chemistry Program is credited for the management of cracking in the CASS pressurizer spray heads and that the One-Time Inspection Program will be used to verify the effectiveness of the Water Chemistry Program in managing cracking of these components. The staff noted that the applicant's response to RAI 3.1.2.2.7.2-1 clarified that this one-time inspection will be done using enhanced VT-1 techniques (EVT-1). The staff finds this to be acceptable because it is in conformance with the recommend AMPs for managing cracking in CASS pressurizers in GALL AMR IV.C2-17, and with the recommended inspection methods in GALL AMP XI.M12 for detecting cracking in CASS materials. RAI 3.1.2.2.7.2-1, Part B is resolved and Open Item 3.1.2.2.7.2-1, Part B is closed.

Based on the programs identified above, pending acceptable resolution of Open Item 3.1.2.2.7.2-1, Parts A and B, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.7 criteria. For those line items that apply to LRA Section 3.1.2.2.7, pending acceptable resolution of Open Item 3.1.2.2.7.2-1, Parts A and B, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.8 Cracking Due to Cyclic Loading

The staff reviewed LRA Section 3.1.2.2.8 against the criteria in SRP-LR Section 3.1.2.2.8.

(1) LRA Section 3.1.2.2.8 addresses cracking due to cyclic loading in BWR jet pump sensing lines, stating that this aging effect is not applicable to IP, which are PWRs.

SRP-LR Section 3.1.2.2.8 states that cracking due to cyclic loading may occur in the stainless steel BWR jet pump sensing lines.

The staff verified that SRP-LR Section 3.1.2.2.8, Item (1) is not applicable to IP2 and IP3 because IP2 and IP3 are PWRs and the staff guidance in this SRP-LR section is only applicable to BWR-designed reactors that are designed with stainless steel jet pump sensing lines.

(2) LRA Section 3.1.2.2.8 addresses cracking due to cyclic loading in BWR isolation condenser components, stating that this aging effect is not applicable to IP, which are PWRs.

SRP-LR Section 3.1.2.2.8 states that cracking due to cyclic loading may occur in steel and stainless steel BWR isolation condenser components exposed to reactor coolant.

The staff verified that SRP-LR Section 3.1.2.2.8, Item (2) is not applicable to IP2 and IP3 because IP2 and IP3 are PWRs and the staff guidance in this SRP-LR section is only applicable to BWR-designed reactors that are designed with isolation condensers.

Based on the above, the staff concludes that SRP-LR Section 3.1.2.2.8 criteria do not apply to the IP2 and IP3 LRA.

3.1.2.2.9 Loss of Preload Due to Stress Relaxation

The staff reviewed LRA Section 3.1.2.2.9 against the criteria in SRP-LR Section 3.1.2.2.9.

LRA Section 3.1.2.2.9 addresses loss of preload due to stress relaxation (creep), stating that this aging effect would be a concern only in very high temperature (more than 700°F) applications as stated in ASME Code, Section II, Part D, Table 4. No IP internals components operate at more than 700°F. Therefore, loss of preload due to stress relaxation (creep) is not an applicable aging effect for reactor vessel internals components. Nevertheless, loss of preload of stainless steel and nickel alloy reactor vessel internals components will be managed to the extent that industry-developed reactor vessel internals AMPs address the aging effect. The applicant's commitment to these programs is in the UFSAR Supplement, LRA Appendix A, Sections A.2.1.41 and A.3.1.41.

SRP-LR Section 3.1.2.2.9 states that loss of preload due to stress relaxation may occur in stainless steel and nickel alloy PWR RVI screws, bolts, tie rods, and hold-down springs exposed to reactor coolant. The GALL Report recommends no further AMR if the applicant commits in the FSAR supplement (1) to participate in the industry programs for investigating and managing aging effects on reactor internals, (2) to evaluate and implement the results of the industry programs as applicable to the reactor internals, and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, to submit an inspection plan for reactor internals to the staff for review and approval.

For Westinghouse-designed RVI, SRP-LR Section 3.1.2.2.9 refers to the staff's guidance in AMR 27 of Table 1 to the GALL Report, Volume 1, and in GALL AMRs IV.B2-5, IV.B2-14, IV.B2-25, IV.B2-33, and IV.B2-38, as applicable to the management of loss of preload due to stress relaxation in Westinghouse-designed RVI baffle/former bolts, clevis insert bolts, lower support plate column bolts, upper internals assembly hold-down springs, and upper support column bolts.

The staff verified that Entergy has made the applicable commitment for these IP2 and IP3 AMRs in Commitment 30, which was provided in a letter dated March 24, 2008, and included in UFSAR Supplements A.2.1.41 and A.3.1.41 for the IP2 and IP3 PWR Vessel Internals Programs, respectively.

Thus, based on this review, the staff finds that the applicant has provided an acceptable basis for using Commitment 30 as its basis for aging management of loss of preload due to stress relaxation in the RVI bolting, hold-down springs and fastener components at IP2 and IP3 because the AMRs for the components are in conformance with the staff's recommended aging management position in GALL AMRs IV.B2-5, IV.B2-14, IV.B2-25, IV.B2-33, and IV.B2-38.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.9 criteria. For those line items that apply to LRA Section 3.1.2.2.9, the staff determines that the LRA is consistent with the GALL Report, and that the applicant's Commitment 30 will adequately address management of loss of preload in the RVI bolting, hold-down springs, and fasteners so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.10 Loss of Material Due to Erosion

The staff reviewed LRA Section 3.1.2.2.10 against the criteria in SRP-LR Section 3.1.2.2.10.

LRA Section 3.1.2.2.10 addresses loss of material due to erosion that could occur in steel steam generator feedwater impingement plates and supports exposed to secondary feedwater, stating that this aging effect is not applicable because the IP SG design employs no feedwater impingement plate.

SRP-LR Section 3.1.2.2.10 states that loss of material due to erosion may occur in steel steam generator feedwater impingement plates and supports exposed to secondary feedwater.

The staff verified that the replacement steam generators (SGs) at IP are Westinghouse Model 44F SGs and that this SG design does not include steel SG impingement plates or supports. Thus, based on this review, the staff finds that the applicant has provided an acceptable basis for concluding that the staff's recommended guidance in SRP-LR Section 3.1.2.2.10 is not applicable to the IP SGs because the new SGs are not designed with feedwater impingement plates and supports that are exposed to secondary water.

Based on the above, the staff concludes that recommended guidance in SRP-LR Section 3.1.2.2.10 does not apply to IP.

3.1.2.2.11 Cracking Due to Flow-Induced Vibration

The staff reviewed LRA Section 3.1.2.2.11 against the criteria in SRP-LR Section 3.1.2.2.11.

LRA Section 3.1.2.2.11 addresses cracking due to flow-induced vibration of BWR steam dryers by stating that this aging effect is not applicable to IP, which are PWRs.

SRP-LR Section 3.1.2.2.11 states that cracking due to flow-induced vibration could occur for the BWR stainless steel steam dryers exposed to reactor coolant.

The staff finds that SRP-LR Section 3.1.2.2.11 is not applicable to IP because IP2 and IP3 are PWRs and the staff guidance in this SRP-LR section is only applicable to the design of steam dryers in BWR-designed reactors.

Based on the above, the staff concludes that the guidance in SRP-LR Section 3.1.2.2.11 does not apply to IP.

3.1.2.2.12 Cracking Due to Stress Corrosion Cracking and Irradiation-Assisted Stress Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.12 against the criteria in SRP-LR Section 3.1.2.2.12.

LRA Section 3.1.2.2.12 addresses cracking due to SCC and irradiation-assisted stress corrosion cracking (IASCC) in PWR stainless steel reactor vessel internal (RVI) components exposed to reactor coolant, stating that, to manage cracking such components, Entergy maintains the Water Chemistry Control - Primary and Secondary Program and will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the staff for review and approval. The applicant's commitment to these programs is in the UFSAR Supplement, LRA Appendix A, Sections A.2.1.41 and A.3.1.41.

SRP-LR Section 3.1.2.2.12 states that SCC and IASCC may occur in PWR stainless steel reactor internals exposed to reactor coolant. The existing program controls water chemistry to mitigate these aging effects. The GALL Report recommends no further AMR if the applicant commits in the FSAR supplement (1) to participate in the industry programs for investigating and managing aging effects on reactor internals, (2) to evaluate and implement the results of the industry programs as applicable to the reactor internals, and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, to submit an inspection plan for reactor internals to the staff for review and approval.

The staff verified that Entergy has made the applicable commitment for these AMRs in Commitment 30, which was provided in a letter dated March 24, 2008, and included in UFSAR Supplements A.2.1.41 and A.3.1.41 for the IP2 and IP3 PWR Vessel Internals Programs, respectively.

Thus, based on this review, the staff finds that the applicant has provided an acceptable basis for using Commitment 30 as its basis for aging management of cracking due to SCC or IASCC in these RVI components because the AMRs for the components are in conformance with the staff's recommended aging management position in SRP-LR Section 3.1.2.2.12 and the aforementioned AMRs in GALL AMRs IV.B2-2, IV.B2-8, IV.B2-10, IV.B2-12, IV.B2-24, IV.B2-30, IV.B2-36, and IV.B2-42.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.12 criteria. For those line items that apply to LRA Section 3.1.2.2.12, the staff determines that the LRA is consistent with the GALL Report and that the applicant's Commitment 30 will adequately address management cracking of the RVI components so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.13 Cracking Due to Primary Water Stress Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.13 against the criteria in SRP-LR Section 3.1.2.2.13.

LRA Section 3.1.2.2.13 addresses cracking due to PWSCC, stating that the Water Chemistry Control - Primary and Secondary, Inservice Inspection, and Nickel Alloy Inspection programs manage this aging effect for most nickel alloy components. The Nickel Alloy Inspection Program implements applicable NRC orders and will implement applicable (1) bulletins and generic letters and (2) staff-accepted industry guidelines. UFSAR Supplement Sections A.2.1.20 and A.3.1.20 include this commitment.

SRP-LR Section 3.1.2.2.13 states that cracking due to PWSCC may occur in PWR components made of nickel alloy and steel with nickel alloy cladding, including reactor coolant pressure boundary components and penetrations inside the reactor coolant system such as pressurizer heater sheathes and sleeves, nozzles, and other internal components. Except for reactor vessel upper head nozzles and penetrations, the GALL Report recommends ASME Code, Section XI ISI (for Class 1 components) and control of water chemistry. For nickel alloy components, no further AMR is necessary if the applicant complies with applicable NRC orders and commits in the FSAR supplement to implement applicable (1) bulletins and generic letters, and (2) staff-accepted industry guidelines.

For Westinghouse-designed PWRs with recirculating SGs, SRP-LR Section 3.1.2.2.13 invokes AMR Item 31 in Table 1 of the GALL Report, Volume 1 and AMR Items IV.A2-12, IV.A2-19, IV.C2-13, IV.C2-21, IV.C2-24, and IV.D1-4, as applicable to the management of cracking due to PWSCC in nickel alloy RV core support pads/lugs; RV bottom mounted instrumentation (BMI) tubes; RCS piping, piping components and piping elements; pressurizer instrumentation nozzles, heater sheaths and sleeves, heater bundle diaphragm plates, manways and flanges; pressurizer surge and steam space nozzles and welds; and SG instrument penetrations and primary side nozzles, safe ends, and welds.

The staff noted that of the possible nickel alloy components listed in the GALL AMRs that are invoked by this SRP-LR item, the Table 2 LRA Tables for the IP2 and IP3 RCS designs only include the following nickel alloy components:

- RV core support pads/lugs (Refer to LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3)
- RV BMI tubes (Refer to LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3)
- ASME Code Class 1 piping, piping components, and piping elements (Refer to LRA Tables 3.1.2-3-IP2 and 3.1.2-3-IP3)

The staff verified that the applicant appropriately aligned its AMRs for these nickel alloy components to LRA AMR 3.1.1-31, which credits the Water Chemistry Control Program – Primary and Secondary, the Inservice Inspection Program, and the Nickel Alloy Inspection Program to manage PWSCC-induced cracking in the nickel alloy component surfaces that are exposed to the borated treated water environment of the reactor coolant. The staff finds this to be acceptable because it is in conformance with recommendations for aging management in AMR Item 31 in Table 1 of the GALL Report, Volume 1. The staff also verified that for the AMRs on cracking of the nickel alloy RV BMI tubes and nickel alloy ASME Code Class 1 piping, piping components, and piping elements, the applicant credited its Water Chemistry Control Program – Primary and Secondary, Inservice Inspection Program, and Nickel Alloy Inspection Program to manage PWSCC-induced cracking in the nickel alloy component surfaces that are exposed to the treated water environment of the reactor coolant. The staff noted that the AMPs credited for aging management of cracking due to PWSCC is in conformance with the staff's recommended aging management position and the AMPs that are recommended for aging management in SRP-LR Section 3.1.2.2.13 and GALL AMRs IV.A2-19, and IV.C2-13. Based on this review, the staff finds that the crediting of these AMPs for management of cracking in the nickel alloy RV BMI tubes and nickel alloy ASME Code Class 1 piping, piping components, and piping elements is acceptable because it is in conformance with the AMPs that are recommended for aging management in SRP-LR Section 3.1.2.2.13 and in GALL AMRs IV.A2-19 and IV.C2-13.

The staff noted that in the applicant's letter of December 18, 2007, the applicant amended its aging management basis in LRA AMR 3.1.1-31 and in the AMRs in LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3 to credit its Water Chemistry Control Program – Primary and Secondary, its Inservice Inspection Program, and its Nickel Alloy Inspection Program to manage cracking of its RV internals core support lugs (pads). GALL AMR IV.A2-12 recommends that AMPs corresponding to GALL AMP XI.M2, "Water Chemistry," and XI.M1, "ASME Section XI Inservice Inspection, Subsections, IWB, IWC, and IWD," be credited to manage cracking in RV core support pads or lugs. In addition, for RV core support pads or lugs that are made of nickel-alloy materials, GALL AMR IV.A2-12 recommends that PWR applicant provide a commitment on the FSAR supplement to submit a plant-specific AMP to implement applicable (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines. . The staff verified that the applicant placed this commitment for the nickel-alloy components as part of the applicant's UFSAR Supplements A.2.1.30 and A.3.1.30 for the Nickel Alloy Inspection Program, which were amended in the applicant's letter of December 18, 2007 to include this commitment. The staff finds that the applicant's amended AMR basis for managing cracking of the RV internal core support lugs is acceptable because it is in conformance with the staff's aging management recommendations for these components in GALL AMR IV.A2-12.

The staff also noted that in SRP-LR Section 3.1.2.2.13, the staff states that no further evaluation of cracking due to PWSCC is necessary for ASME Code Class 1 nickel alloy components if PWR applicants for license renewal state in the LRA UFSAR Supplements that they will comply with applicable NRC Orders on nickel alloy cracking and if they place a commitment in their LRA UFSAR supplement to "implement applicable (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines." The staff reviewed LRA Section A.2.1.20, "Nickel Alloy Inspection Program," and noted that in the applicant's LRA letter of March 12, 2008, the applicant responded to RAI 3.0.3.3.5-2 and committed to: (1) comply with applicable NRC Orders on nickel alloy components and (2) conform to applicable NRC Bulletins, Generic Letters and NRC-staff accepted industry guidelines associated with nickel alloy components. The staff also verified that in the applicant's letter of June 11, 2008, the applicant amended UFSAR Supplement Sections A.2.1.20 for the IP2 Nickel Alloy Inspection Program and UFSAR Supplement Section A.3.1.20 for the IP3 Nickel Alloy Inspection Program and placed the nickel alloy commitment referred to in the applicant's letter of June 11, 2008, in the appropriate UFSAR Supplement Sections for the applicant's Nickel Alloy Inspection Program. The staff noted that this is consistent with the staff's recommended further evaluation guidance and nickel alloy commitment basis that is provided in SRP-LR Section 3.1.2.2.13 and in GALL AMRs IV.A2-12, IV.A2-19, and IV.C2-13

The staff verified that, consistent with the documentation in WCAP-14574-A, which was approved by the staff in a safety evaluation dated October 26, 2000 (ADAMS Accession number ML003763768), the applicant's AMRs in the LRA indicated that the IP2 and IP3 pressurizer designs do not include nickel alloy pressurizer components. The staff noted this was consistent with the design basis information for the IP2 and IP3 pressurizer designs that was provided in WCAP-14574-NP-A. Based on this review, the staff finds that the applicant has provided an acceptable basis for concluding that recommendations in GALL AMRs IV.C2-21 and IV.C2-24 are not applicable to the IP2 and IP3 LRA because the staff has verified, based on a review of WCAP-14574-NP-A, that the IP2 and IP3 pressurizer designs do not include any nickel alloy pressurizer instrumentation nozzles, heater sheaths and sleeves, heater bundle diaphragm plates, manways and flanges; pressurizer surge and steam space nozzles and welds.

The staff also noted that, in LRA Table 3.1.2-4-IP2 and 3.1.2-4-IP3, the applicant did include AMRs for cracking of the nickel alloy SG primary nozzle closure rings, and that in these AMRs, the applicant credited only its Water Chemistry Control Program – Primary and Secondary to manage cracking in the component surfaces that are exposed to borated treated water.
By letter dated December 30, 2008, the staff issued RAI 3.1.2-1, Part C, and asked the applicant to justify why the applicant has aligned its AMRs for the SG primary nozzle closure rings to GALL AMR IV.D1-6 which is for SG divider plates, and why the Inservice Inspection Program was not credited in addition to the Water Chemistry Control Program – Primary and

Secondary to manage cracking due to SCC or PWSCC in the SG primary nozzle closure rings. This is part of Open Item 3.1.2-1. The issue on whether the AMRs in LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3 on cracking of nickel alloy SG primary nozzle closure rings need to credit the Inservice Inspection Program as an additional AMP for managing cracking in the SG primary nozzle closure rings is pending acceptable resolution of RAI 3.1.2-1, Part C (Open Item 3.1.2-1).

The applicant responded to RAI 3.1.2-1, Part C in a letter dated January 27, 2009. In this response the applicant explained that GALL AMR IV.D1-6 is only applicable to SG divider plates which are not part of the primary pressure boundary. The applicant also explained that the SG primary closure nozzle closure rings are fabricated from nickel alloy materials, they are not reactor coolant pressure boundary components, and are therefore not subject to ASME Code, Section XI inservice inspection requirements. The staff finds the applicant's response to RAI 3.1.2-1, Part C provides an acceptable basis for not crediting the ISI program for the SG feedwater nozzle closure rings because the rings are not categorized as ASME Code Class 1 reactor coolant pressure boundary components, and because the applicant would only be required to apply the ISI requirements of the applicant's Inservice Inspection Program to the rings if they were ASME Code Class 1 reactor coolant pressure components. The staff also finds that the applicant has provided an acceptable basis for not using GALL AMR Item IV.D1-6 for the SG feedwater nozzle closure rings because GALL AMP IV.-D1-6 is applicable to SG divider plates made from nickel alloy materials. RAI 3.1.2-1, Part C is resolved and Open Item 3.1.2-1 is closed with respect to the AMPs that need to be credited for aging management of cracking due to PWSCC of the SG feedwater nozzle closure rings.

Based on the programs identified above, and resolution of Open Item 3.1.2-1, Part C, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.13 criteria. For those line items that apply to LRA Section 3.1.2.2.13, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.14 Wall Thinning Due to Flow-Accelerated Corrosion

The staff reviewed LRA Section 3.1.2.2.14 against the criteria in SRP-LR Section 3.1.2.2.14.

LRA Section 3.1.2.2.14 addresses wall thinning due to flow-accelerated corrosion, stating that it could occur in steel feedwater inlet rings and supports. The Steam Generator Integrity Program manages loss of material due to flow-accelerated corrosion in the feedwater inlet ring using periodic visual inspections.

SRP-LR Section 3.1.2.2.14 states that wall thinning due to flow accelerated corrosion may occur in steel feedwater inlet rings and supports. The GALL Report references IN 91-19, "Steam Generator Feedwater Distribution Piping Damage," for evidence of flow-accelerated corrosion in steam generators and recommends that a plant-specific AMP be evaluated because existing programs may not be capable of mitigating or detecting wall thinning due to flow accelerated corrosion.

For Westinghouse-design PWRs with recirculation SGs, SRP-LR Section 3.1.2.2.14 invokes AMR Item 32 in the GALL Report, Volume 1 and AMR Item IV.D1-26, as applicable to loss of material (wall thinning) due to flow accelerated corrosion in SG FW inlet rings and supports.

The staff verified that in LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3, the applicant includes AMRs on management of loss of material (wall thinning) in the SG feedwater rings and fittings that are made from carbon steel and that are exposed internally to treated water. The staff also verified that in these AMRs, the applicant credits a combination of its Water Chemistry Control Program – Primary and Secondary and its Steam Generator Integrity Program to manage loss of material in the internal SG FW ring surfaces.

The staff noted that in GALL AMR IV.D1-26, the staff recommends that a plant-specific program be evaluated and credited to address operating experience discussed in IN 91-19. The staff requested the applicant to discuss the type of visual inspections that could detect the wall thinning of carbon steel FW rings and supports, as noted in IN 91-19 (Audit Item 199). Although the description of the SG integrity AMP includes other mechanically induced phenomena, such as denting, wear, impingement damage, and fatigue, no details are found in the LRA about how the inspection methods and their evaluation are performed with regard to loss of material in carbon steel FW inlet ring and supports in the IP SGs. In response, dated December 18, 2007, the applicant stated that the SG integrity program includes processes for monitoring and maintaining secondary side components. Visual inspections are performed by qualified vendors.

The staff notes that SGs were replaced at IP2 in 2001 and at IP3 in 1989. Therefore, the FW ring inspections have not been performed in the IP2 SGs, but are scheduled in two of its SGs in 2010. However, the FW ring inspections were performed in IP3 SGs in: 1992 (all four), 1997 (34SG), 1999 (33SG), 2001 (32SG), and 2007 (31SG and 32SG). The inspections included visual examinations of the outer diameter (OD) of the ring and a fiberscope inspection of the inner diameter (ID) of 5 selected J-nozzles of 36 total and the FW ring tee. The inspection also included various support structures including the feedring hangers. No anomalies were noted other than minor washed out areas of the feedring beneath the outlet of the J-nozzles. The next inspection is scheduled in two SGs in 2013. Therefore, the staff concluded that wall thinning due to flow-accelerated corrosion is properly managed by the SG integrity program and hence, finds it acceptable.

Based on the programs identified above, the staff concludes that the applicant’s programs meet SRP-LR Section 3.1.2.2.14 criteria. For those line items that apply to LRA Section 3.1.2.2.14, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.15 Changes in Dimensions Due to Void Swelling

The staff reviewed LRA Section 3.1.2.2.15 against the criteria in SRP-LR Section 3.1.2.2.15.

LRA Section 3.1.2.2.15 addresses changes in dimensions due to void swelling, stating that it could occur in stainless steel and nickel alloy reactor vessel internal components exposed to reactor coolant. To manage changes in dimensions of such components, Entergy will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the staff for review and approval. This commitment is in the UFSAR Supplement, LRA

Appendix A, Sections A.2.1.41 and A.3.1.41.

SRP-LR Section 3.1.2.2.15 states that changes in dimensions due to void swelling may occur in stainless steel and nickel alloy PWR internal components exposed to reactor coolant. The GALL Report recommends no further AMR if the applicant commits in the FSAR supplement (1) to participate in the industry programs for investigating and managing aging effects on reactor internals, (2) to evaluate and implement the results of the industry programs as applicable to the reactor internals, and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, to submit an inspection plan for reactor internals to the staff for review and approval.

For Westinghouse-designed reactor vessel internals, SRP-LR Section 3.1.2.2.15 refers to the staff's guidance in AMR 33 of Table 1 to the GALL Report, Volume 1, and in GALL AMRs IV.B2-1, IV.B2-4, IV.B2-7, IV.B2-11, IV.B2-15, IV.B2-19, IV.B2-23, IV.B2-27, IV.B2-29, IV.B2-35, IV.B2-39, and IV.B2-41, as applicable to the management of changes in dimensions due to void swelling in Westinghouse-designed RVI baffle/former plates; baffle/former bolts; core barrel (CB), CB flange, CB outlet nozzles and thermal shield; flux thimble guide tubes; flux thimble guide tubes; lower internal assembly – fuel alignment pins, lower support plate column bolts, and clevis insert bolts; lower internals assembly – lower core plate radial keys and clevis inserts; lower internals assembly – lower support casting or forging and lower support columns; RCCA guide tube assemblies – RCCA guide tube bolts and RCCA guide tube support pins; RCCA guide tube assemblies – RCCA guide tubes; upper internals assembly – upper support columns; upper internals assembly – upper support column bolts, upper core plates, and fuel alignment pins; and upper internals assembly – upper support plates, upper core plates, and hold-down springs.

The staff verified that Entergy has made the applicable commitment for these AMRs in Commitment 30, which was provided in Entergy letter dated March 24, 2008, and included in UFSAR Supplements A.2.1.41 and A.3.1.41 for the IP2 and IP3 PWR Vessel Internals Programs, respectively.

Thus, based on this review, the staff finds that the applicant has provided an acceptable basis for using Commitment 30 as its basis for aging management of changes in dimension due to void swelling in these RVI components because the AMRs for the components are in conformance with the staff's recommended aging management position in SRP-LR Section 3.1.2.2.12 and GALL AMRs IV.B2-1, IV.B2-4, IV.B2-7, IV.B2-11, IV.B2-15, IV.B2-19, IV.B2-23, IV.B2-27, IV.B2-29, IV.B2-35, IV.B2-39, and IV.B2-41.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.15 criteria. For those line items that apply to LRA Section 3.1.2.2.15, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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

The staff reviewed LRA Section 3.1.2.2.16 against the criteria in SRP-LR Section 3.1.2.2.16.

(1) LRA Section 3.1.2.2.16 addresses cracking due to SCC in stainless steel control rod drive head penetration components and on the primary coolant side of steel steam generator heads clad with stainless steel, stating that the Water Chemistry Control - Primary and Secondary and Inservice Inspection programs manage this aging effect. The Water Chemistry Control - Primary and Secondary, Inservice Inspection, and Reactor Vessel Head Penetration Inspection programs manage cracking of nickel alloy control rod drive head penetration components due to PWSCC. The Reactor Vessel Head Penetration Inspection Program implements applicable NRC orders and will implement applicable (1) bulletins and generic letters and (2) staff-accepted industry guidelines. The UFSAR Supplement, LRA Appendix A, Sections A.2.1.30 and A.3.1.30, state this commitment. The Water Chemistry Control - Primary and Secondary and Steam Generator Integrity programs manage cracking for the steam generator tubesheets.

SRP-LR Section 3.1.2.2.16, Item (1) states that cracking due to SCC may occur on the primary coolant side of PWR steel steam generator upper and lower heads, tubesheets, and tube-to-tube sheet welds made or clad with stainless steel. Cracking due to PWSCC may occur on the primary coolant side of PWR steel steam generator upper and lower heads, tubesheets, and tube-to-tube sheet welds made or clad with nickel alloy. The GALL Report recommends ASME Code, Section XI ISI and control of water chemistry to manage this aging effect and recommends no further AMR for PWSCC of nickel alloy if the applicant complies with applicable NRC orders and commits in the FSAR supplement to implement applicable (1) bulletins and generic letters, and (2) staff-accepted industry guidelines.

The staff noted that, in LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3, consistent with GALL Report, the applicant credited its Water Chemistry Control Program – Primary and Secondary and Inservice Inspection Program to manage cracking of the stainless steel CRD pressure housings. The staff noted that this is appropriate for the stainless steel base metals used to fabricate the CRD pressure housings. However, the staff noted that the welds used to join the stainless steel CRD pressure housings to the nickel alloy upper RVCH penetration nozzles (e.g., CRD mechanism penetration nozzles) would normally be fabricated from bimetallic (nickel alloy) weld materials. Thus, the staff noted that for the CRD housing bimetallic weld materials, the applicant did not include the appropriate commitment in UFSAR Supplements A.2.1.20 and A.3.1.20. By letter dated December 30, 2008, the staff issued RAI 3.1.2-1, and asked whether the weld used to secure the CRD housings to the nickel alloy upper RVCH penetration nozzles were made of nickel alloy filler weld materials. If so, the staff requested that the applicant amend the LRA to provide AMRs on the IP2 and IP3 SG CRD pressure housing-to-CRD penetration nozzle welds that credit the Water Chemistry Control Program – Primary and Secondary, the Inservice Inspection Program, and the Nickel Alloy Inspection Program, as bases for managing cracking of these bimetallic (nickel alloy) weld materials along with the appropriate commitment that was made for Nickel alloy components in the applicant's letter dated March 12, 2008, as amended by letter dated June 11, 2008. This was identified as Open Item 3.1.2-1, Part A.

In its response dated January 27, 2009, the applicant clarified that the CETNA nozzles used in the upper RV head designs are fabricated from stainless steel and do not include any nickel alloy base metal or weld materials. Instead, the applicant clarified that the CETNA assemblies are fabricated as follows:

> A CET head port adapter is connected to the penetration housing adapter flange, and then connected to the CETNA assembly via a conoseal joint. All CETNA assemblies are sealed to the CET columns with Grafoil seals using a compression collar and a hold down nut with no welds. As shown in the LRA tables, the CETNA are constructed from stainless steel. Based on this supplemental information, the applicant has provided an acceptable basis for concluding that the CETNA assemblies do not need to be within the scope of and managed by the Nickel Alloy Inspection Program because these components do not include any nickel alloy base metal or weld components.

In its response to RAI 3.1.2-1, the applicant also clarified that the only nickel alloy welds associated with the upper RVCH vent nozzles are those nickel alloy welds that join these nozzles to the nickel alloy closure head vent nozzle safe-end. The applicant explained the vent nozzles are carbon steel nozzles with internal stainless steel cladding that are weld to the carbon steel upper RVCH using carbon steel weld materials that have been post weld heat treated. The applicant clarified that the nickel alloy welds associated with the nickel alloy vent nozzle safe ends are within the scope of the applicant's Nickel Alloy Inspection Program. Based on this review, the staff finds that the applicant has provided an acceptable basis for concluding that the upper RVCH head vent nozzle-to-upper RVCH welds do not need to be managed by or be within the scope of either the Nickel Alloy Inspection Program or Reactor Vessel Head Penetration Inspection Program because these components and their associated welds are not fabricated from nickel alloy materials.

Based on this review, the staff finds that the applicant has provided an acceptable basis for managing cracking in these upper RVCH head vent nozzles and CETNA nozzles because: (1) the applicant has clarified which of nozzle designs include nickel alloy base metal or weld materials, (2) the applicant has appropriately credited its Nickel Alloy Inspection Program and Water Chemistry Program to manage cracking in the nickel alloy upper RVCH head vent nozzle safe ends and their nickel alloy safe-end-to-nozzle welds, and (3) in the applicant's AMRs for the CETNA nozzles and upper RVCH head vent nozzles, as given in LRA Tables 3.1.2-IP2-1 and 3.1.2-IP3, the applicant has appropriately credited its Water Chemistry Program and Inservice Inspection Program to manage any cracking that may develop in the components. RAI 3.1.2-1 is resolved and Open Item 3.1.2-1, Part A is closed with respect to the management of cracking in the upper RVCH head vent nozzles and the CETNA nozzles.

The staff verified that the staff's aging management recommendations in GALL AMR IV.D2-4 for primary side steel SG upper and lower heads, tubesheets and tube-to-tubesheet welds with internal stainless steel or nickel alloy cladding is not applicable to the IP2 LRA because the IP2 is currently designed with Model 44F recirculating SGs, and because the staff's guidance in AMR IV.D2-4 is only applicable to once-through SG designs. The staff noted, however, that for these components, the applicant credited its Water Chemistry Control – Primary and Secondary and Steam Generator Integrity

Programs to manage cracking due to SCC in the components. The staff noted that this is appropriate for the SG upper and lower heads because the cladding on these components is made from stainless steel and because this is consistent with the staff's recommendations in GALL AMR IV.D2-4 for stainless steel SG cladding that is exposed to the reactor coolant.

The staff noted, however, that the internal cladding for the SG tubesheets is made from nickel alloy material, and that in the LRA, the applicant did not commit to applying any applicable (1) bulletins and generic letters, and (2) staff-accepted industry guidelines to the any nickel alloy cladding associated with the tubesheets. By letter dated December 18, 2007, in the response to Audit Item 200, the applicant stated that it is committed to implement NRC Orders, bulletins, generic letters, and staff-accepted industry guidelines associated with nickel alloy cladding associated with the SG tubesheets.

Based on this review, the staff finds that the applicant has created an acceptable basis for managing cracking in these nickel alloy components. This is based on the fact that the applicant is crediting the Water Chemistry Program, the Inservice Inspection Program and either the commitment associated with the Nickel Alloy Inspection Program or Reactor Vessel Penetration Inspection Program to manage cracking in the nickel alloy upper RVCH penetration nozzles or housings. In addition, the applicant will use the Water Chemistry Program, Steam Generator Integrity Program, and commitment associated with Nickel Alloy Inspection Program to manage cracking in the nickel alloy SG tubesheet cladding,

(2) LRA Section 3.1.2.2.16 addresses cracking due to SCC that could occur on stainless steel pressurizer spray heads and cracking due to PWSCC that could occur on nickel alloy pressurizer spray heads. The IP pressurizer spray heads are composed of CASS. LRA Section 3.1.2.2.7 item 2 addresses management of cracking for these components.

SRP-LR Section 3.1.2.2.16 states that cracking due to SCC may occur on stainless steel pressurizer spray heads. Cracking due to PWSCC may occur on nickel alloy pressurizer spray heads. The existing program controls water chemistry to mitigate this aging effect. The GALL Report recommends one-time inspection to confirm that cracking has not occurred. For nickel alloy welded spray heads, the GALL Report recommends no further AMR if the applicant complies with applicable NRC orders and commits in the FSAR supplement to implement applicable (1) bulletins and generic letters, and (2) staff-accepted industry guidelines.

The staff verified that in the applicant's AMR on cracking of the IP2 pressurizer spray head, the applicant identifies that the spray heads are made of CASS. Thus, the staff verified that the guidance in SRP-LR Section 3.1.2.2.16 is not applicable to the evaluation of management of cracking in the IP2 and IP3 pressurizer spray heads because the spray heads are not fabricated from nickel alloy materials. The staff 's evaluation of the AMRs for managing cracking of the IP2 and IP3 pressurizer spray heads which are made from CASS materials is documented in Section 3.1.2.2.7, Item (2).

Based on its review, the staff concludes that the applicant's programs, discussed above, meet SRP-LR Section 3.1.2.2.16 criteria for the AMRs that are used to manage cracking in the upper RVCH nozzle tube (i.e., the CRDM penetration nozzles) and housing welds and the SG tubesheet cladding. For the AMR items that apply to LRA Section 3.1.2.2.16, 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). Based on this review, the staff has determined that the guidance in SRP-LR Section 3.1.2.2.16.2 is not applicable to the management of cracking in the IP2 and IP3 pressurizer spray heads because the spray heads are not fabricated from nickel alloy materials. The staff evaluates the applicant's AMRs for managing cracking of the CASS pressurizer spray heads in SER Section 3.1.2.2.7, Item (2).

3.1.2.2.17 Cracking Due to Stress Corrosion Cracking, Primary Water Stress Corrosion Cracking, and Irradiation-Assisted Stress Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.17 against the criteria in SRP-LR Section 3.1.2.2.17.

LRA Section 3.1.2.2.17 addresses cracking due to SCC, PWSCC, and IASCC, stating that they could occur in PWR stainless steel and nickel alloy reactor vessel internals components. To manage cracking for such components, Entergy maintains the Water Chemistry Control – Primary and Secondary Program and will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the staff for review and approval. The applicant's commitment to these programs is in the UFSAR Supplement, LRA Appendix A, Sections A.2.1.41 and A.3.1.41.

SRP-LR Section 3.1.2.2.17 states that cracking due to SCC, PWSCC, and IASCC may occur in PWR stainless steel and nickel alloy reactor vessel internals components. The existing program controls water chemistry to mitigate these aging effects; however, the existing program should be augmented to manage these aging effects for reactor vessel internals components. The GALL Report recommends no further AMR if the applicant commits in the FSAR supplement (1) to participate in the industry programs for investigating and managing aging effects on reactor internals, (2) to evaluate and implement the results of the industry programs as applicable to the reactor internals, and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, to submit an inspection plan for reactor internals to the staff for review and approval.

For Westinghouse-designed reactors, SRP-LR Section 3.1.2.2.17 invokes AMR Item 37 in Table 1 of the GALL Report, Volume 1 and GALL AMR IV.B2-16, IV.B2-20, IV.B2-28, and IV.B2-40, as applicable to the management of cracking due to SCC, PWSCC, or IASCC in Westinghouse RVI lower internals assembly – fuel alignment pins, lower support plate column bolts, and clevis insert bolts; lower internals assembly – lower core plate, radial keys and clevis inserts; RCCA guide tube assemblies – RCCA guide tubes bolts and RCCA guide tubes support pins; and upper internals assembly – upper support column bolts, upper core plate alignment pins, and fuel alignment pins. The staff's aging management recommendations in these GALL-based AMRs is the same as that recommended in SRP-LR 3.1.2.2.17.

The staff verified that, in these AMRs, the applicant credited its Water Chemistry Control Program – Primary and Secondary and LRA Commitment No. 30 to manage cracking of stainless steel and nickel alloy reactor vessel internals components. The staff finds that this is acceptable because it is in conformance with the guidance in SRP-LR Section 3.1.2.2.17 and in the GALL AMRs that are based on this SRP-LR section. The staff also verified that, for these AMRs (and other AMRs on aging management of the RVI components), Entergy has made the applicable commitment for IP2 and IP3 in Commitment 30, which was provided in Entergy letter dated March 24, 2008, and included in UFSAR Supplement Sections A.2.1.41 and A.3.1.41 for the IP2 and IP3 PWR Vessel Internals Programs, respectively. The staff finds this acceptable because it is in conformance with the staff's recommended aging management position that is given in SRP-LR Section 3.1.2.2.17 and in the GALL AMRs that are based on this SRP-LR section.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.17 criteria. For those line items that apply to LRA Section 3.1.2.2.17, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.18 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.

3.1.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.1.2-1-IP2 through 3.1.2-4-IP2 and 3.1.2-1-IP3 through 3.1.2-4-IP3, 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 these LRA tables, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided more information about how it will manage the aging effects. Specifically, Note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation. The following sections document the staff's evaluation.

3.1.2.3.1 Reactor Vessel—Summary of Aging Management Review

The staff reviewed LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3, which summarize the results of AMR evaluations for the RV component groups. The staff's review did not identify any line items with plant-specific Notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

SER Section 3.1.2.1 documents the staff's evaluation of the line items with Notes A through E.

3.1.2.3.2 Reactor Vessel Internals—Summary of Aging Management Review

The staff reviewed LRA Tables 3.1.2-2-IP2 and 3.1.2-2-IP3, which summarize the results of AMR evaluations for the RVI component groups. The staff's review did not identify any line items with plant-specific Notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

SER Section 3.1.2.1 documents the staff's evaluation of the line items with Notes A through E.

3.1.2.3.3 Reactor Coolant System and Pressurizer—Summary of Aging Management Review

The staff reviewed LRA Tables 3.1.2-3-IP2 and 3.1.2-3-IP3, which summarize the results of AMR evaluations for the RCPB.

LRA Tables 3.1.2-3-IP2 and 3.1.3-3-IP3 include AMRs on management of fouling in stainless steel RCS HX tubes whose external surfaces are exposed to treated borated water in a greater than 60 degrees C (140 degrees F) environment. In these AMRs, the applicant credits its Water Chemistry Control—Primary and Secondary Program with managing fouling affecting the heat transfer function of stainless steel HX tubes externally exposed to treated borated water in a greater than 60 degrees C (140 degrees F) environment. These AMRs are marked with a Note H, indicating that this aging effect is not in the GALL Report for this component and material.

In Audit Item 190, the staff asked the applicant to explain how it ensures the effectiveness of the water chemistry control. By letter dated December 18, 2007, the applicant stated that fouling of HX tubes occurs due to the lack of effective water chemistry control on the tube surface and that contaminants, such as corrosion products, often deposit on the tube surfaces, which reduces their heat transfer capability. The applicant stated that treating the water chemistry to reduce the development of any contaminants would minimize the fouling of the HX tubes. To verify the effectiveness of the water chemistry programs, the applicant will use the One-Time Inspection Program to inspect the external surfaces of these HX tubes during the period of extended operation. The applicant stated that, to accomplish this, it will amend the AMRs for these HX tubes by adding LRA RCS AMR Note 104, which indicates that a One-Time Inspection will be performed to verify the effectiveness of the Water Chemistry Control—Primary and Secondary Program in managing aging.

The staff verified that, in the applicant's letter of December 18, 2007, the applicant appropriately amended the AMRs on loss of material for these stainless steel HX components by adding LRA RCS AMR Note 104. The staff noted that the applicant's amended basis for aging management conforms with other AMRs in the GALL Report, Volume 2, for PWR systems (such as GALL AMR V.A-16) in which a program corresponding to GALL AMP XI.M2, "Water Chemistry," is recommended for aging management of loss of heat transfer capability due to fouling in stainless steel HX tubes exposed to treated water, and for which a program corresponding to GALL AMP XI.M32, "One-Time Inspection," is recommended for verification of the effectiveness of the water chemistry program in managing this aging effect. Thus, the staff finds the applicant's basis for aging management to be acceptable because (1) the implementation of the

Water Chemistry Control—Primary and Secondary Program would minimize the buildup of contaminants that could lead to corrosion products and fouling in HX tubes, (2) the implementation of the One-Time Inspection Program would verify that this process is not occurring, and (3) this approach conforms with the staff's aging management basis in GALL AMR V.A-16.

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

3.1.2.3.4 Steam Generator—Summary of Aging Management Review

The staff reviewed LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3, which summarize the results of AMR evaluations for the SG component groups.

LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3 include AMRs on management of fouling in nickel alloy SG tubes whose internal surfaces are exposed to treated borated water and whose external surfaces are exposed to treated water. In these AMRs, the applicant credits its Water Chemistry Control—Primary and Secondary Program with managing the loss of heat transfer function due to fouling on internal surfaces that are exposed to treated borated water and whose external surfaces are exposed to treated water. These AMRs are marked with Note H, indicating that this aging effect is not in the GALL Report for this component and material.

In Audit Item 190, the staff asked the applicant to explain how it would ensure the effectiveness of the water chemistry control. By letter dated December 18, 2007, the applicant stated that fouling of SG tubes occurs due to the lack of effective water chemistry control on the tube surface and that contaminants, such as corrosion products, often deposit on the tube surfaces, which reduces their heat transfer capability. The applicant stated that treating the water chemistry to reduce the development of any contaminants would minimize the fouling of the SG tubes. To verify the effectiveness of the water chemistry programs, the applicant will use the One-Time Inspection Program to inspect the external surfaces of these SG tubes during the period of extended operation. The applicant stated that, to accomplish this, it will amend the AMRs for these tubes by adding LRA RCS AMR Note 104, which indicates that a One-Time Inspection will be performed to verify the effectiveness of the Water Chemistry Control—Primary and Secondary Program in managing aging.

The staff verified that, in the applicant's letter of December 18, 2007, the applicant had appropriately amended the AMRs on loss of heat transfer function due to fouling for these nickel alloy SG components by adding LRA RCS AMR Note 104. The staff noted that the applicant's amended basis for aging management conforms with other AMRs in the GALL Report, Volume 2, for PWR systems (such as GALL AMR V.A-16) in which a program corresponding to GALL AMP XI.M2, "Water Chemistry," is recommended for aging management of loss of heat transfer capability due to fouling in HX tubes exposed to treated water type environments, and for which a program corresponding to GALL AMP XI.M32, "One-Time Inspection," is recommended for verification of the effectiveness of the water chemistry program in managing this aging effect. Thus, the staff finds the applicant's basis for aging management to be acceptable because (1) the implementation of the Water Chemistry Control—Primary and Secondary Program would minimize the buildup of contaminants that could lead to corrosion products and fouling in SG tubes, (2) the implementation of the One-Time Inspection Program would be used to verify that this is not occurring, and (3) this approach conforms with the staff's aging management basis in GALL AMR V.A-16.

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

3.1.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the RV, RVI, and RCS 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 following engineered safety feature (ESF) system components and component groups:

- RHR system
- CS system
- containment isolation support system
- safety injection system
- containment penetrations

3.2.1 Summary of Technical Information in the Application

LRA Section 3.2 provides AMR results for the ESF system components and component groups. LRA Table 3.2.1, "Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of NUREG-1801," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the ESF system components and component groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included CRs and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.2.2 Staff Evaluation

The staff reviewed LRA Section 3.2 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for the ESF system components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff conducted an onsite audit of AMRs to verify the applicant's claim that certain AMRs are consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA is applicable and that the applicant identified the appropriate GALL Report AMRs. SER Section 3.0.3 documents the staff's evaluations of the AMPs. SER Section 3.2.2.1 documents the details of the staff's audit evaluation.

During an onsite audit, the staff also selected AMRs consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's additional evaluations are consistent with the SRP-LR Section 3.2.2.2 acceptance criteria. SER Section 3.2.2.2 documents the staff's evaluations.

The staff also conducted a technical review of the remaining AMRs not consistent with or not addressed in the GALL Report. The technical review evaluated whether the applicant identified all plausible aging effects and whether the aging effects listed are appropriate for the material-environment combinations specified. SER Sections 3.2A.2.3 (for IP2) and 3.2B.2.3 (for IP3) document the staff's evaluations.

For components that the applicant claimed are not applicable or require no aging management, the staff reviewed the AMR line items and the plant's operating experience to verify the applicant's claims.

Table 3.2-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.2 and addressed in the GALL Report.

Table 3.2-1 Staff Evaluation for Engineered Safety Features System Components in the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel and stainless steel piping, piping components, and piping elements in emergency core cooling system (3.2.1-1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Consistent with GALL Report (see SER Section 3.2.2.2.1)
Steel with stainless steel cladding pump casing exposed to treated borated water (3.2.1-2)	Loss of material due to cladding breach	A plant-specific AMP is to be evaluated. Reference NRC Information Notice 94-63, "Boric Acid Corrosion of Charging Pump Casings Caused by Cladding Cracks"	Yes	Not applicable	Not applicable (see SER Section 3.2.2.2.2)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel containment isolation piping and components internal surfaces exposed to treated water (3.2.1-3)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry Control – Primary and Secondary and One-Time Inspection	Consistent with GALL Report (see SER Section 3.2.2.2.3(1))
Stainless steel piping, piping components, and piping elements exposed to soil (3.2.1-4)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable (see SER Section 3.2.2.2.3(2))
Stainless steel and aluminum piping, piping components, and piping elements exposed to treated water (3.2.1-5)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.2.3(3))
Stainless steel and copper alloy piping, piping components, and piping elements exposed to lubricating oil (3.2.1-6)	Loss of material due to pitting and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	Oil Analysis and One-Time Inspection	Consistent with GALL Report (see SER Section 3.2.2.2.3(4))
Partially encased stainless steel tanks with breached moisture barrier exposed to raw water (3.2.1-7)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated for pitting and crevice corrosion of tank bottoms because moisture and water can egress under the tank due to cracking of the perimeter seal from weathering.	Yes	Not applicable	Not applicable (see SER Section 3.2.2.2.3(5))
Stainless steel piping, piping components, piping elements, and tank internal surfaces exposed to condensation (internal) (3.2.1-8)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	One-Time Inspection	Consistent with GALL Report (see SER Section 3.2.2.2.3(6))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel, stainless steel, and copper alloy HX tubes exposed to lubricating oil (3.2.1-9)	Reduction of heat transfer due to fouling	Lubricating Oil Analysis and One-Time Inspection	Yes	Oil Analysis and One-Time Inspection	Consistent with GALL Report (see SER Section 3.2.2.2.4(1))
Stainless steel HX tubes exposed to treated water (3.2.1-10)	Reduction of heat transfer due to fouling	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable (see SER Section 3.2.2.2.4(2))
Elastomer seals and components in standby gas treatment system exposed to air - indoor uncontrolled (3.2.1-11)	Hardening and loss of strength due to elastomer degradation	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.2.5)
Stainless steel high-pressure safety injection (HPSI) (charging) pump miniflow orifice exposed to treated borated water (3.2.1-12)	Loss of material due to erosion	A plant-specific AMP is to be evaluated for erosion of the orifice due to extended use of the centrifugal HPSI pump for normal charging.	Yes	Not applicable	Not applicable (see SER Section 3.2.2.2.6)
Steel drywell and suppression chamber spray system nozzle and flow orifice internal surfaces exposed to air - indoor uncontrolled (internal) (3.2.1-13)	Loss of material due to general corrosion and fouling	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.2.7)
Steel piping, piping components, and piping elements exposed to treated water (3.2.1-14)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.2.2.2.8(1))
Steel containment isolation piping, piping components, and piping elements internal surfaces exposed to treated water (3.2.1-15)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry Control – Primary and Secondary and One-Time Inspection	Consistent with GALL Report (see SER Section 3.2.2.2.8(2))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to lubricating oil (3.2.1-16)	Loss of material due to general, pitting, and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	Oil Analysis and One-Time Inspection	Consistent with GALL Report (see SER Section 3.2.2.2.8(3))
Steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil (3.2.1-17)	Loss of material due to general, pitting, crevice, and microbiologically -influenced corrosion	Buried Piping and Tanks Surveillance or Buried Piping and Tanks Inspection	No Yes	Not applicable	Not applicable (see SER Section 3.2.2.2.9)
Stainless steel piping, piping components, and piping elements exposed to treated water > 60°C (> 140°F) (3.2.1-18)	Cracking due to stress corrosion cracking (SCC) and intergranular stress corrosion cracking (IGSCC)	BWR Stress Corrosion Cracking and Water Chemistry	No	Not applicable	Not applicable to PWRs
Steel piping, piping components, and piping elements exposed to steam or treated water (3.2.1-19)	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	No	Not applicable	Not applicable to PWRs
Cast austenitic stainless steel piping, piping components, and piping elements exposed to treated water (borated or unborated) > 250°C (> 482°F) (3.2.1-20)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS	No	Not applicable	Not applicable to PWRs
High-strength steel closure bolting exposed to air with steam or water leakage (3.2.1-21)	Cracking due to cyclic loading, SCC	Bolting Integrity	No	Not applicable	Not applicable (see SER Section 3.2.2.1.1)
Steel closure bolting exposed to air with steam or water leakage (3.2.1-22)	Loss of material due to general corrosion	Bolting Integrity	No	Not applicable	Not applicable (see SER Section 3.2.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel bolting and closure bolting exposed to air - outdoor (external), or air - indoor uncontrolled (external) (3.2.1-23)	Loss of material due to general, pitting, and crevice corrosion	Bolting Integrity	No	Bolting Integrity	Consistent with GALL Report
Steel closure bolting exposed to air - indoor uncontrolled (external) (3.2.1-24)	Loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	No	Bolting Integrity	Consistent with GALL Report (see SER Section 3.2.2.1.2)
Stainless steel piping, piping components, and piping elements exposed to closed cycle cooling water > 60°C (> 140°F) (3.2.1-25)	Cracking due to SCC	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable (see SER Section 3.2.2.1.1)
Steel piping, piping components, and piping elements exposed to closed-cycle cooling water (3.2.1-26)	Loss of material due to general, pitting, and crevice corrosion	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable (see SER Section 3.2.2.1.1)
Steel heat exchanger components exposed to closed-cycle cooling water (3.2.1-27)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	No	Water Chemistry Control – Closed Cooling Water	Consistent with GALL Report
Stainless steel piping, piping components, piping elements, and HX components exposed to closed-cycle cooling water (3.2.1-28)	Loss of material due to pitting and crevice corrosion	Closed-Cycle Cooling Water System	No	Water Chemistry Control – Closed Cooling Water	Consistent with GALL Report
Copper alloy piping, piping components, piping elements, and HX components exposed to closed-cycle cooling water (3.2.1-29)	Loss of material due to pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	No	Water Chemistry Control – Closed Cooling Water	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and copper alloy HX tubes exposed to closed-cycle cooling water (3.2.1-30)	Reduction of heat transfer due to fouling	Closed-Cycle Cooling Water System	No	Water Chemistry Control – Closed Cooling Water	Consistent with GALL Report
External surfaces of steel components including ducting, piping, ducting closure bolting, and containment isolation piping external surfaces exposed to air - indoor uncontrolled (external); condensation (external) and air - outdoor (external) (3.2.1-31)	Loss of material due to general corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring	Consistent with GALL Report
Steel piping and ducting components and internal surfaces exposed to air - indoor uncontrolled (Internal) (3.2.1-32)	Loss of material due to general corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Externals Surfaces Monitoring, Fire Protection, or Periodic Surveillance and Preventive Maintenance	Consistent with GALL Report (see SER Section 3.2.2.1.3)
Steel encapsulation components exposed to air - indoor uncontrolled (internal) (3.2.1-33)	Loss of material due to general, pitting, and crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable	Not applicable (see SER Section 3.2.2.1.1)
Steel piping, piping components, and piping elements exposed to condensation (internal) (3.2.1-34)	Loss of material due to general, pitting, and crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable	Not applicable (see SER Section 3.2.2.1.1)
Steel containment isolation piping and components internal surfaces exposed to raw water (3.2.1-35)	Loss of material due to general, pitting, crevice, and microbiologically -influenced corrosion, and fouling	Open-Cycle Cooling Water System	No	Not applicable	Not applicable (see SER Section 3.2.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel HX components exposed to raw water (3.2.1-36)	Loss of material due to general, pitting, crevice, galvanic, and microbiologically -influenced corrosion, and fouling	Open-Cycle Cooling Water System	No	Not applicable	Not applicable (see SER Section 3.2.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to raw water (3.2.1-37)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion	Open-Cycle Cooling Water System	No	Periodic Surveillance and Preventive Maintenance	Consistent with GALL Report (see SER Section 3.2.2.1.4)
Stainless steel containment isolation piping and components internal surfaces exposed to raw water (3.2.1-38)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion, and fouling	Open-Cycle Cooling Water System	No	Not applicable	Not applicable (see SER Section 3.2.2.1.1)
Stainless steel HX components exposed to raw water (3.2.1-39)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion, and fouling	Open-Cycle Cooling Water System	No	Not applicable	Not applicable (see SER Section 3.2.2.1.1)
Steel and stainless steel HX tubes (serviced by open-cycle cooling water) exposed to raw water (3.2.1-40)	Reduction of heat transfer due to fouling	Open-Cycle Cooling Water System	No	Not applicable	Not applicable (see SER Section 3.2.2.1.1)
Copper alloy > 15% Zn piping, piping components, piping elements, and HX components exposed to closed cycle cooling water (3.2.1-41)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Selective Leaching	Consistent with GALL Report
Gray cast iron piping, piping components, piping elements exposed to closed-cycle cooling water (3.2.1-42)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Selective Leaching	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Gray cast iron piping, piping components, and piping elements exposed to soil (3.2.1-43)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Not applicable	Not applicable (see SER Section 3.2.2.1.1)
Gray cast iron motor cooler exposed to treated water (3.2.1-44)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Not applicable	Not applicable (see SER Section 3.2.2.1.1)
Aluminum, copper alloy > 15% Zn, and steel external surfaces, bolting, and piping, piping components, and piping elements exposed to air with borated water leakage (3.2.1-45)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	No	Boric Acid Corrosion Prevention	Consistent with GALL Report
Steel encapsulation components exposed to air with borated water leakage (internal) (3.2.1-46)	Loss of material due to general, pitting, crevice and boric acid corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable	Not applicable (see SER Section 3.2.2.1.1)
Cast austenitic stainless steel piping, piping components, and piping elements exposed to treated borated water > 250°C (> 482°F) (3.2.1-47)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS	No	Not applicable	Not applicable (see SER Section 3.2.2.1.1)
Stainless steel or stainless-steel-clad steel piping, piping components, piping elements, and tanks (including safety injection tanks/accumulators) exposed to treated borated water > 60°C (> 140°F) (3.2.1-48)	Cracking due to SCC	Water Chemistry	No	Water Chemistry Control – Primary and Secondary	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel piping, piping components, piping elements, and tanks exposed to treated borated water (3.2.1-49)	Loss of material due to pitting and crevice corrosion	Water Chemistry	No	Water Chemistry Control – Primary and Secondary	Consistent with GALL Report
Aluminum piping, piping components, and piping elements exposed to air - indoor uncontrolled (internal/external) (3.2.1-50)	None	None	NA	None	Consistent with GALL Report
Galvanized steel ducting exposed to air - indoor controlled (external) (3.2.1-51)	None	None	NA	Not applicable	Not applicable (see SER Section 3.2.2.1.1)
Glass piping elements exposed to air - indoor uncontrolled (external), lubricating oil, raw water, treated water, or treated borated water (3.2.1-52)	None	None	NA	None	Consistent with GALL Report
Stainless steel, copper alloy, and nickel alloy piping, piping components, and piping elements exposed to air - indoor uncontrolled (external) (3.2.1-53)	None	None	NA	None	Consistent with GALL Report
Steel piping, piping components, and piping elements exposed to air - indoor controlled (external) (3.2.1-54)	None	None	NA	Not applicable	Not applicable (see SER Section 3.2.2.1.1)
Steel and stainless steel piping, piping components, and piping elements in concrete (3.2.1-55)	None	None	NA	None	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel, stainless steel, and copper alloy piping, piping components, and piping elements exposed to gas (3.2.1-56)	None	None	NA	None	Consistent with GALL Report
Stainless steel and copper alloy < 15% Zn piping, piping components, and piping elements exposed to air with borated water leakage (3.2.1-57)	None	None	NA	None	Consistent with GALL Report

The staff's review of the ESF system component groups followed any one of several approaches. In one approach, documented in SER Section 3.2.2.1, the staff reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. In the second approach, documented in SER Section 3.2.2.2, the staff reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. In the third approach, documented in SER Sections 3.2A.2.3 (for IP2) and 3.2B.2.3 (for IP3), the staff reviewed AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. SER Section 3.0.3 documents the staff's review of AMPs credited to manage or monitor aging effects of the ESF system components.

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 system components:

- Bolting Integrity Program
- Boric Acid Corrosion Prevention Program
- Buried Piping and Tanks Inspection Program
- External Surfaces Monitoring Program
- Heat Exchanger Monitoring Program
- Oil Analysis Program
- One-Time Inspection Program
- Periodic Surveillance and Preventive Maintenance Program
- Selective Leaching Program
- Water Chemistry Control - Auxiliary Systems Program
- Water Chemistry Control - Closed Cooling Water Program
- Water Chemistry Control - Primary and Secondary Program

LRA Tables 3.2.2-1-IP2 through 3.2.2-5-IP2 and 3.2.2-1-IP3 through 3.2.2-5-IP3 summarize the results of AMRs for the ESF 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 with the report, where the report 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.

For each AMR line item, the applicant stated how the information in the tables aligns with the information in the GALL Report. Notes A through E indicate how the AMR is consistent with the GALL Report. The staff audited these AMRs.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report and validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report and verified that the identified exceptions to the GALL Report AMPs have been reviewed and accepted. The staff also determined whether the applicant's AMP was consistent with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the 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 line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review and whether the identified exceptions to the GALL Report AMPs have been reviewed and accepted. The staff also determined whether the applicant's AMP was consistent with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but credits a different AMP. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the credited AMP would manage the aging effect consistently with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

The staff audited and reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs.

In response to RAIs 2.3A.2.3-1 and 2.3B.2.3-2, by letter dated December 6, 2007, the applicant revised the LRA to include an AMR line item for aluminum valve body with an internal environment of treated air, an external environment of indoor air, and an aging effect of "none," and Note C or Note C with plant-specific Note 301.

In response to RAI 2.3A.2.2-1, by letter dated March 12, 2008, the applicant revised the LRA to include several AMR line items associated with the CS (IP2) system which were not previously included within the scope of license renewal under 10 CFR 54.4(a)(2). The AMR line items added included stainless steel bolting, flow indicator, piping, tubing, and valve body with internal environments of treated water or indoor air, external environment of indoor air, an aging effect of "loss of material" or "none," and Notes A or C.

By letter dated June 30, 2009, the applicant submitted an annual update to the LRA, identifying changes made to the CLB that materially affect the contents of the LRA. For the containment isolation support system, the applicant revised LRA Table 3.2.2-3-IP2 to add AMR line items for stainless steel piping exposed internally to treated air with an aging effect of "none," and exposed externally to soil with an aging effect of "loss of material." These line items were annotated with plant-specific Note 201 and/or Note C.

The staff reviewed the applicant's revisions, noted above, and found that the additional AMR results are consistent with the GALL Report for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

On the basis of its audit and review, the staff determines that, for AMRs not requiring further evaluation, as identified in LRA Table 3.2.1, the applicant's references to the GALL Report are acceptable and no further evaluation is required.

3.2.2.1.1 AMR Results Identified as Not Applicable

In LRA Table 3.2.1, the applicant identifies Items 21, 22, 25, 26, 33, 34, 35, 36, 38, 39, 40, 43, 44, 46, 47, 51, and 54, as not applicable since the component, material, and environment combination does not exist at IP. For each of these items, the staff reviewed the LRA and the applicant's supporting documents, and confirmed the applicant's claim that the component, material, and environment combination does not exist at IP. On the basis that IP does not have this combination, the staff finds that these AMRs are not applicable to IP.

LRA Table 3.2.1, Line Item 18 addresses stainless steel piping, piping components, and piping elements exposed to treated water >60°C (>140 °F) in BWRs. The LRA states that this line item is only applicable to boiling water reactor (BWR) designs, and, therefore, it is not applicable. Since IP2 and IP3 are both PWRs, the staff finds this line item is not applicable.

LRA Table 3.2.1, Line Item 19 addresses steel piping, piping components, and piping elements exposed to steam or treated water. The LRA states that this line item is only applicable to BWR designs, and, therefore, it is not applicable. Since IP2 and IP3 are both PWRs, the staff finds this line item is not applicable.

LRA Table 3.2.1, Line Item 20 addresses cast austenitic stainless steel piping, piping components, and piping elements exposed to treated water (borated or unborated) > 250°C (>482 °F). The LRA states that this line item is only applicable to BWR designs, and, therefore, it is not applicable. Since IP2 and IP3 are both PWRs, the staff finds this line item is not applicable.

3.2.2.1.2 Steel Closure Bolting Exposed to Air-Indoor Uncontrolled

In the discussion column of LRA Table 3.2.1, Item 3.2.1-24, the applicant stated that loss of preload is a design-driven effect and not an AERM. This statement is contrary to the GALL Report recommendation. During the audit, the staff asked the applicant to justify why other aging effects are not applicable and why the Bolting Integrity Program (B.1.2) did not take exception to the GALL Report since at Indian Point, loss of preload is not considered an aging effect (Audit Item 270).

In its response dated, December 18, 2007, the applicant stated:

> The review of IPEC operating experience did not identify instances in which mechanical components failure was attributable to loss of pressure boundary bolting preload. This is consistent with the EPRI Mechanical Tools (EPRI 1010639, Appendix F, Section 3.1) that do not consider loss of preload an aging effect for bolted closures. Gasket creep will normally occur shortly after initial loading, which allows for addressing this mechanism by installing practices and subsequent maintenance of the joint. Self-loosening is also not an aging mechanism but is an event-driven mechanism that occurs due to improper joint design or installation that doesn’t properly consider the potential for this mechanism. This would be detected early in component service life and actions would be taken to prevent recurrence.
>
> The program addresses all bolting regardless of size except reactor head closure stud, which are addressed by the Reactor Head Closure Studs Program. The program relies on industry recommendations for comprehensive bolting maintenance, as delineated in EPRI TR-104213 for pressure retaining bolting and structural bolting. The Bolting Integrity Program also includes preventive measures to preclude or minimize loss of preload, which is consistent with the GALL report so an exception to the GALL program description was not required.
>
> Commitment 2 will be clarified to specifically state the Bolting Integrity Program manages loss of preload and loss of material for all external loading.
>
> Clarification to be incorporated into the LRA.

The staff finds the applicant’s response acceptable, because the Bolting Integrity Program includes preventive measures that preclude or minimize loss of preload. This is consistent with the GALL Report. In the same letter, the applicant amended the LRA to provide clarification as stated above. On this basis, the staff finds the AMR results for this line item acceptable.

3.2.2.1.3 Loss of Material Due to General Corrosion

In the discussion column of LRA Table 3.2.1, Item 3.2.1-32, the applicant stated that loss of material from the internal surfaces of steel components exposed to indoor air is managed by the Externals Surfaces Monitoring, Fire Protection, and Periodic Surveillance and Preventive Maintenance Programs. During the audit, the staff asked the applicant to elaborate on how the Fire Protection Program would manage the loss of carbon steel components and to explain why the associated Table 2 items did not credit this. The staff also asked the applicant to compare the HX (housing) inspection frequency between the Periodic Surveillance and Preventive Maintenance Program proposed by the applicant and the External Surfaces Monitoring Program recommended by the GALL Report (Audit Item 272).

In its response, dated December 18, 2007, the applicant stated:

> As in the associated Table 2 line items, either the Fire Protection Program or the Periodic Surveillance and Preventive Maintenance Programs manage loss of material of carbon steel components by periodic visual inspection of component internal surfaces. One or the other program is adequate: both programs are not necessary. Table 3.3.2-12-IP2 and Table 3.3.2-12-IP3 include line items referring to Item 3.2.1-32 and crediting the Fire Protection Program. The associated components are part of the Halon or carbon dioxide gaseous fire protection systems. The specific components referencing Item 3.2.1-32 are distribution header components that are open to the atmosphere resulting in an indoor air internal environment.
>
> The Fire Protection Program manages loss of material for external carbon steel components by visual inspection of external surface. The IP2 cable spreading room Halon fire suppression system is visually inspected under the Fire Protection Program. The IP3 cable spreading room, 480V switchgear room, and EDG [emergency diesel generator] room CO_2 fire suppression system is visually inspected under the Fire Protection Program. For systems where internal carbon steel surfaces are exposed to the same environment as external surfaces, external surfaces will be representative of internal surfaces. Thus, loss of material on internal carbon steel surfaces is also managed by the Fire Protection Program
>
> Table 2 items that refer to Table 1 Item 3.2.1-32 credit the PSPM [periodic surveillance and preventive maintenance] for internal surfaces of carbon steel heat exchanger (housing) with an environment of indoor-air. The PSPM Program inspections are performed at least once per 5 years. Loss of material due to corrosion is a long-term aging effect for carbon steel components air in-door (int). The affected components have been in service for the life of the plant without significant corrosion. Based on the slow acting aging mechanisms confirmed by plant operating experience, the inspection frequency of at least once per 5 years is sufficient. The intervals of inspections may be adjusted, as necessary, based on inspection experience. The GALL program “Inspection of Internal Surfaces and Miscellaneous Piping and Duct Components” includes visual inspections to assure that existing environmental conditions are not causing material degradation that could result in a loss of component intended functions. Locations are chosen to include conditions likely to exhibit these aging effects

and inspection intervals are established such that they provide timely detection of degradation.

The staff reviewed the AMR result lines referring to Note E and determined that the component type, material, environment, and aging effect are consistent with those of the corresponding line of the GALL Report. The staff's review of the applicant's Periodic Surveillance and Preventive Maintenance Program and its evaluation is documented in SER Sections 3.0.3.3.7. The staff noted that the applicant's inspection frequency, which is based on the plant-specific operating experience, will provide for timely detection of aging prior to the loss of intended functions. The staff further noted that the applicant's inspection frequency of the periodic visual inspections may increase based on the inspection results. On the basis of its review, the staff finds the applicant's response acceptable because (1) the applicant's inspection frequency has been adjusted based on their plant specific operating experience, which is consistent with the recommendations provided in GALL AMP XI.M38 and (2) the applicant's inspection frequency may be altered based on the inspection results, which may increase the inspection frequency. The staff finds that this program includes activities that are consistent with the recommendations in the GALL Report, and are adequate to manage loss of material of carbon steel HX housings exposed to indoor air through visual inspections.

The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with the GALL Report. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff reviewed the AMR result lines referring to Note E, as amended by letters dated April 30, 2008, June 11, 2008, and June 30, 2009, and determined that the component type, material, environment, and aging effect are consistent with those of the corresponding line of the GALL Report. The staff's review of the applicant's Fire Protection Program and its evaluation is documented in SER Section 3.0.3.2.7. The staff's review of the applicant's External Surfaces Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.5. The staff finds that these programs include activities that are consistent with the recommendations in the GALL Report, and are adequate to manage loss of material of carbon steel piping, pump casings (External Surfaces Monitoring Program only), and valve bodies exposed to indoor air through visual inspections.

The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with the GALL Report. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.1.4 Stainless Steel Piping, Piping Components and Piping Elements Exposed to Raw Water

In LRA Tables 3.2.2-1-IP2 and 3.2.2-1-IP3, which cite Table 3.2.1, Item 3.2.1-37, the applicant proposed to manage loss of material of stainless steel piping, piping components and piping elements exposed to raw water using Periodic Surveillance and Preventive Maintenance Program. However, the AMP recommended by the GALL Report for this AERM is GALL AMP XI.M20, "Open-Cycle Cooling Water System." The applicant referred to Note E to the Table 2 line items indicating that a different AMP is credited.

The staff reviewed the AMR result lines referring to Note E and determined that the component type, material, environment, and aging effect are consistent with those of the corresponding line of the GALL Report. The staff's review of the applicant's Periodic Surveillance and Preventive Maintenance Program and its evaluation is documented in SER Section 3.0.3.3.7. The staff finds that this program includes activities that are consistent with the recommendations in the GALL Report, and are adequate to manage loss of material of material of stainless steel piping, piping components and piping elements exposed to raw water through visual inspections.

The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with the GALL Report. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation Is Recommended

In LRA Section 3.2.2.2, the applicant further evaluated aging management, as recommended by the GALL Report, for the ESF system components and provided information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to cladding (breach)
- loss of material due to pitting and crevice corrosion
- reduction of heat transfer due to fouling
- hardening and loss of strength due to elastomer degradation
- loss of material due to erosion
- loss of material due to general corrosion and fouling
- loss of material due to general, pitting, and crevice corrosion
- loss of material due to general, pitting, crevice, and microbiologically-influenced 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 report recommends further evaluation, the staff audited and reviewed the applicant's evaluation to determine whether it adequately addresses 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 states that fatigue is a TLAA, as defined in 10 CFR 54.3, "Definitions." Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(c)(1). SER Section 4.3 documents the staff's review of the applicant's evaluation of this TLAA.

During the audit, the staff noted that numerous line items in Tables 3.2.2-1-IP2 and 3.2.2-1-IP3 credit "TLAA—Metal Fatigue" to manage the aging effect of cumulative fatigue damage and indicate that Section 4.3 of the LRA addresses the evaluation. However, in LRA Section 4.3, it appears that the text does not include the discussion for certain components, such as flex hose, flow elements, thermowell, and tubing. The staff asked the applicant to explain the discrepancy (Audit Item 267).

In its response dated December 18, 2007, the applicant stated the following:

> The components identified, with the exception of flex hoses, are all considered part of the "piping and in-line components" line item identified in LRA Table 4.1-1 and 4.1-2 and as such are evaluated as part of the system. ASME B31.1 stress analysis is performed as required for the RHR system. These components are addressed by the 7000 cycle discussion in LRA Section 4.3.2 and further details are provided in section 3 of the TLAA—Mechanical Fatigue report IP-RPT-06-LRD04. The flex hoses should not be included as part of the TLAA evaluation since they isolate portions of the system from each other and would not be part of a specific stress analysis for the system or parts of the system. The line items for the flex hose in the RHR system in Tables 3.2.2-1-IP2 and 3.2.2-1-IP3 that identify TLAA—Metal Fatigue will be removed.
>
> Clarification to be incorporated into the LRA.

The staff finds the applicant's response acceptable, because the applicant has explained that the components identified by the staff, with the exception of flex hoses, are considered piping and in-line components, which will be evaluated as part of their respective systems. The applicant further explained that the discussion in LRA Section 4.3.2 addresses these components. The applicant explained that the component flex hose is not part of a specific stress analysis and agreed to clarify this in the LRA. The staff verified, in the letter dated December 18, 2007, that the applicant amended the LRA to remove the flex hose component with the following material, environment, aging effect and program combination : stainless steel, treated borated water greater than 140 °F, cracking-fatigue and TLAA—metal fatigue from LRA Table 3.2.2-1-1P2. This component/material/environment combination is not applicable to IP3, therefore an amendment to LRA Table 3.2.2-1-1P3 was not required.

3.2.2.2.2 Loss of Material Due to Cladding (Breach)

The staff reviewed LRA Section 3.2.2.2.2 against the criteria in SRP-LR Section 3.2.2.2.2.

LRA Section 3.2.2.2.2 addresses loss of material due to cladding breach. It states that this aging effect is not applicable because there are no stainless-steel-clad steel pump casings in IP ESF systems.

SRP-LR Section 3.2.2.2.2 states that loss of material due to cladding breach may occur in pressurized-water reactor (PWR) steel pump casings with stainless steel cladding exposed to treated borated water.

The staff finds that this item is not applicable because the IP2 and IP3 ESF do not have steel pump casings with stainless steel cladding exposed to treated borated water.

Based on the above, the staff concludes that SRP-LR Section 3.2.2.2.2 criteria do not apply.

3.2.2.2.3 Loss of Material Due to Pitting and Crevice Corrosion

The staff reviewed LRA Section 3.2.2.2.3 against the criteria in SRP-LR Section 3.2.2.2.3.

(1) LRA Section 3.2.2.2.3 addresses loss of material due to pitting and crevice corrosion for internal surfaces of stainless steel piping and components in containment isolation components exposed to treated water and states that the Water Chemistry Control - Primary and Secondary Program manages this aging effect. The One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control - Primary and Secondary Program by an inspection of a representative sample of components crediting this program, including those in areas of stagnant flow and other susceptible locations.

SRP-LR Section 3.2.2.2.3 states that loss of material due to pitting and crevice corrosion may occur on internal surfaces of stainless steel containment isolation piping, piping components, and piping elements exposed to treated water. The existing AMP monitors and controls water chemistry to mitigate degradation. However, control of water chemistry does not preclude loss of material due to pitting and crevice corrosion at locations with stagnant flow conditions; therefore, the effectiveness of water chemistry control programs should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to verify the effectiveness of water chemistry control programs. A one-time inspection of selected components at susceptible locations is an acceptable method to determine whether an aging effect is occurring or is slowly progressing such that the component's intended functions will be maintained during the period of extended operation.

The staff reviewed the Water Chemistry Control - Primary and Secondary Program, which monitors chlorides, fluorides, and dissolved oxygen to limit the contaminants, thus minimizing the occurrences of aging effects and maintaining component ability to perform intended functions. The applicant has stated that the Water Chemistry Control - Primary and Secondary Program will be verified for effectiveness by the One-Time Inspection Program. The One-time Inspection Program provides inspection of selected stainless steel components exposed to treated water at susceptible locations such as stagnant areas for loss of material due to pitting and crevice corrosion in applicable ESF systems. The staff evaluated the Water Chemistry Control—Primary and Secondary Program and the One-time Inspection Program and documented the evaluations in Sections 3.0.3.2.17 and 3.0.3.1.9, respectively. The staff finds that these programs include activities that are consistent with the recommendations in the GALL Report and are adequate to manage loss of material due to pitting and crevice corrosion on internal surfaces of stainless steel containment isolation piping and components exposed to treated water.

(2) LRA Section 3.2.2.2.3 addresses loss of material from pitting and crevice corrosion for stainless steel piping and piping components exposed to a soil environment, stating that the Buried Piping and Tanks Inspection Program manages this aging effect. The Buried Piping and Tanks Inspection Program includes (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel, copper alloy, gray cast iron, and stainless steel components. Buried components will be inspected when excavated during maintenance, within 10 years of entering the period of extended operation, and within the first 10 years of the period of extended operation unless opportunistic inspections occur within these 10-year periods.

SRP-LR Section 3.2.2.2.3 states that loss of material due to pitting and crevice corrosion may occur in stainless steel piping, piping components, and piping elements exposed to soil. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that the aging effect is adequately managed.

During the audit, the staff noted that IP3 has two line items in Table 3.2.2-2 (Containment Spray) and Table 3.2.2-4 (Safety Injection Systems), which correspond to GALL Report Item V.D1-26, Piping, Piping Components and Piping Elements, and reference Table 1, Item 3.2.1-4. The staff asked the applicant to explain why IP2 does not have similar items and why the Buried Piping and Tanks Program is adequate for managing the aging effect of loss of material due to pitting and crevice corrosion (Audit Item 268).

In its response, dated December 18, 2007, the applicant stated the following:

> GALL V.D1-26 is for buried piping. While the IP3 configuration of this piping includes a section of buried piping exposed to soil, the IP2 piping configuration for these systems does not include buried piping exposed to soil. The Buried Piping and Tanks Program is consistent with the GALL program and includes surveillance and preventive measures to manage loss of material due to the corrosion by protecting the external surface of buried carbon steel piping and tanks.

The staff verified that IP2 does not have ESF piping exposed to soil, and therefore, this item is not applicable to IP2.

On the basis of its review, the staff finds the applicant's Buried Piping and Tanks Program adequate to manage the effects of aging for IP3 because the applicant's program provide for surveillance and preventive measures that include coating the buried carbon steel piping and tanks on the external surface to mitigate corrosion, which is consistent with the recommendations in GALL AMP XI.M28.

(3) LRA Section 3.2.2.2.3 addresses loss of material due to pitting and crevice corrosion in BWR stainless steel and aluminum piping and states that this aging effect is not applicable to IP, which are PWRs.

SRP-LR Section 3.2.2.2.3 states that loss of material due to pitting and crevice corrosion may occur in BWR stainless steel and aluminum piping, piping components, and piping elements exposed to treated water.

This item is not applicable to IP because IP2 and IP3 are PWRs. On this basis, the staff finds that the SRP-LR 3.2.2.2.3(3) criteria do not apply to IP.

(4) LRA Section 3.2.2.2.3 addresses loss of material due to pitting and crevice corrosion and states that it could occur in copper alloy and stainless steel piping and components in ESF systems exposed to lubricating oil. The Oil Analysis Program manages loss of material by periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits to preserve an environment not conducive to corrosion. The One-Time Inspection Program will use visual inspections or NDEs of representative samples to confirm the effectiveness of the Oil Analysis Program in managing aging effects for components crediting this program.

SRP-LR Section 3.2.2.2.3 states that loss of material due to pitting and crevice corrosion may occur in stainless steel and copper alloy piping, piping components, and piping elements exposed to lubricating oil. The existing program periodically samples and analyzes lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment that is not conducive to corrosion. However, control of lube oil contaminants may not always be fully effective in precluding corrosion. Therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation to verify the effectiveness of the lubricating oil programs. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that intended functions of components will be maintained during the period of extended operation.

The staff reviewed the Oil Analysis Program, which monitors oil chemical and physical properties, wear metals, contaminants, additives, and water and thus minimizes the occurrence of aging effects and maintains component ability to perform intended functions. The effectiveness of the Oil Analysis Program is verified by the One-Time Inspection Program. The One-Time Inspection Program provides inspection of selected stainless steel and copper alloy components exposed to lubricating oil for loss of material due to pitting and crevice corrosion in applicable ESF systems. The staff evaluated the Oil Analysis and the One-Time Inspection Programs and documented the evaluations in SER Sections 3.0.3.2.12 and 3.0.3.1.9, respectively. The staff finds that these programs include activities that are consistent with the recommendations in the GALL Report and are adequate to manage loss of material due to pitting and crevice corrosion in stainless steel and copper piping and components exposed to lubricating oil.

(5) LRA Section 3.2.2.2.3 addresses loss of material from pitting and crevice corrosion. It states that this aging effect is not applicable to IP2 and IP3 ESF system outdoor

stainless steel tank bottoms exposed to raw water. Their design includes a perimeter seal under the tank lip and grouting behind the seal between the concrete foundation and the tank bottom to a depth of 18 inches which precludes the entry of water leaking from the outside and moving under the tank bottoms.

SRP-LR Section 3.2.2.2.3 states that loss of material due to pitting and crevice corrosion may occur in partially encased stainless steel tanks exposed to raw water due to cracking of the perimeter seal from weathering.

During the audit, the staff asked the applicant to identify the specific stainless tanks and their functions in the ESF systems that are applicable and to provide the equipment drawings of each applicable tank for onsite review.

As documented in the Audit Report (ADAMS Accession No. ML083540662), the staff reviewed equipment drawings for IP2 and IP3 and confirmed that the design included a fibrated rope seal around the lip of the tank, a 1-inch layer of grout that was placed behind the fibrated rope seal after the tank was welded, and a hot-poured bitumastic put on the outside perimeter of the tank after it was erected. The RWSTs were also erected on an elevated surface which was designed with a gradual decline around the perimeter to preclude outside water from leaking under the tanks.

The staff agrees with the applicant's determination that Item (5) of SRP-LR Section 3.2.2.2.3 does not apply to IP ESF systems because the moisture barrier configuration prevents exposure to raw water in the ESF system.

(6) LRA Section 3.2.2.2.3 addresses loss of material from pitting and crevice corrosion for ESF stainless steel components internally exposed to condensation and states that the One-Time Inspection Program manages this aging effect by using visual and other non-destructive examination (NDE) techniques to verify that loss of material has not occurred or is so insignificant that no AMP for these components is warranted.

SRP-LR Section 3.2.2.2.3 states that loss of material due to pitting and crevice corrosion may occur in stainless steel piping, piping components, piping elements, and tanks exposed to internal condensation. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that the aging effect is adequately managed.

During the audit, the staff asked the applicant to explain how a one-time inspection will be performed on these components and why a One-Time Inspection Program is sufficient to manage the aging effect of loss of material due to pitting and crevice corrosion (Audit Item 269).

In a letter dated December 18, 2007, the applicant responded:

> Parameter to be monitored or inspected is wall thickness. Inspection techniques will be visual (VT-I or equivalent) or volumetric (RT or UT) inspection.
>
> The normal internal environment for the gas analyzers is air/gas with material of stainless steel and no aging effects. Since condensation may be possible, a one time inspection was conservatively included to verify

that unacceptable pitting and crevice corrosion, although not expected, is not occurring, thereby confirming that there is no need for an ongoing aging management program for the period of extended operation. As specified in the One-Time Inspection Program, unacceptable inspection findings will be evaluated in accordance with the site corrective action process to determine the need for subsequent (including periodic) inspections and for monitoring and trending the results.

The staff noted that the One-Time Inspection Program will confirm that loss of material is not occurring or is insignificant for internal stainless steel surfaces exposed to condensation in ESF systems. This program uses visual and other NDE techniques to confirm that loss of material is not occurring or is so insignificant that an AMP for these components is not warranted. The staff evaluated the One-Time Inspection Program and documented the evaluation in SER Section 3.0.3.1.9. The staff finds that this program include activities that are consistent with the recommendations in the GALL Report and are adequate to manage loss of material due to pitting and crevice corrosion for ESF stainless steel components internally exposed to condensation.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.2.2.2.3 criteria. For those line items that apply to LRA Section 3.2.2.2.3, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.4 Reduction of Heat Transfer Due to Fouling

The staff reviewed LRA Section 3.2.2.2.4 against the criteria in SRP-LR Section 3.2.2.2.4.

(1) LRA Section 3.2.2.2.4 addresses reduction of heat transfer due to fouling in copper alloy HX tubes exposed to lubricating oil in ESF systems and states that the Oil Analysis Program manages this aging effect. This program periodically samples and analyzes lubricating oil to maintain contaminants within acceptable limits to preserve an environment that is not conducive to fouling. The One-Time Inspection Program will use visual inspections or NDEs of representative samples to ascertain whether the Oil Analysis Program has been effective in managing aging effects for components crediting this program.

SRP-LR Section 3.2.2.2.4 states that reduction of heat transfer due to fouling may occur in steel, stainless steel, and copper alloy HX tubes exposed to lubricating oil. The existing AMP monitors and controls lube oil chemistry to mitigate reduction of heat transfer due to fouling. However, control of lube oil chemistry may not always be fully effective in precluding fouling; therefore, the effectiveness of lube oil chemistry control should be verified to ensure that fouling does not occur. The GALL Report recommends further evaluation of programs to verify the effectiveness of lube oil chemistry control. A one-time inspection of selected components at susceptible locations is an acceptable method to determine whether an aging effect is occurring or is slowly progressing such that the component's intended functions will be maintained during the period of extended operation.

The staff reviewed the Oil Analysis Program, which monitors oil chemical and physical properties, excessive metal loss caused by wear, contaminants, additives, and water and thus minimizes the occurrence of aging effects and maintains component ability to perform intended functions. The effectiveness of the Oil Analysis Program is verified by the One-Time Inspection Program. The One-Time Inspection Program provides inspection of stainless steel and copper HX tubes exposed to lubricating oil for reduction of heat transfer due to fouling at susceptible locations where contaminants can accumulate in applicable ESF systems. The staff evaluated the Oil Analysis and the One-Time Inspection Programs and documented the evaluations in SER Sections 3.0.3.2.12 and 3.0.3.1.9, respectively. The staff finds that these programs include activities that are consistent with the recommendations in the GALL Report and are adequate to manage reduction of heat transfer due to fouling in copper HX tubes exposed to lubricating oil.

(2) LRA Section 3.2.2.2.4 addresses reduction of heat transfer due to fouling for stainless steel HX tubes exposed to treated water. It states that this aging effect is not applicable because there are no stainless steel HX tubes with an intended function of heat transfer exposed to treated water in the ESF systems.

SRP-LR Section 3.2.2.2.4 states that reduction of heat transfer due to fouling may occur in stainless steel HX tubes exposed to treated water.

The staff agrees that Item (2) of SRP-LR Section 3.2.2.2.4 does not apply to IP ESF systems because IP2 and IP3 do not have stainless steel HX tubes exposed to treated water with an intended function of heat transfer in the ESF systems.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.2.2.2.4 criteria. For those line items that apply to LRA Section 3.2.2.2.4, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.5 Hardening and Loss of Strength Due to Elastomer Degradation

The staff reviewed LRA Section 3.2.2.2.5 against the criteria in SRP-LR Section 3.2.2.2.5.

LRA Section 3.2.2.2.5 addresses hardening and loss of strength due to elastomer degradation, stating that this aging effect is not applicable to IP, which are PWRs.

SRP-LR Section 3.2.2.2.5 states that hardening and loss of strength due to elastomer degradation may occur in elastomer seals and components of the BWR standby gas treatment system ductwork and filters exposed to air—indoor uncontrolled.

This item is not applicable to IP because IP2 and IP3 are PWRs. On this basis, the staff finds that SRP-LR 3.2.2.2.5 criteria do not apply to IP.

Based on the above, the staff concludes that SRP-LR Section 3.2.2.2.5 criteria do not apply.

3.2.2.2.6 Loss of Material Due to Erosion

The staff reviewed LRA Section 3.2.2.2.6 against the criteria in SRP-LR Section 3.2.2.2.6.

LRA Section 3.2.2.2.6 addresses loss of material due to erosion in the stainless steel high-pressure safety injection (HPSI) pump miniflow recirculation orifice exposed to treated borated water and states that this aging effect is not applicable because IP2 and IP3 use separate positive displacement pumps for normal makeup to the RCS.

SRP-LR Section 3.2.2.2.6 states that loss of material due to erosion may occur in the stainless steel HPSI pump miniflow recirculation orifice exposed to treated borated water.

During its review, the staff examined the applicant's updated final safety analysis report and associated plant drawings to verify the applicant's statement that the HPSI pumps were infrequently used. The staff noted that the HPSI miniflow recirculation lines containing flow orifices are used only during emergency core cooling system injection or during HPSI pump testing. The staff also noted that HPSI pumps are actuated only during testing and are not used during normal charging. Since loss of material due to erosion can occur in these components only if they are frequently operated, the staff finds that erosion is not plausible for IP HPSI pumps and flow orifices. On this basis, the staff agrees that SRP-LR Section 3.2.2.2.6 criterion does not apply to IP2 and IP3 ESF systems.

Based on the above, the staff concludes that SRP-LR Section 3.2.2.2.6 criteria do not apply.

3.2.2.2.7 Loss of Material Due to General Corrosion and Fouling

The staff reviewed LRA Section 3.2.2.2.7 against the criteria in SRP-LR Section 3.2.2.2.7.

LRA Section 3.2.2.2.7 addresses loss of material due to general corrosion and fouling on steel drywell and suppression chamber spray system nozzle and flow orifice internal surfaces exposed to air—indoor uncontrolled and states that this aging effect is not applicable to IP, which are PWRs.

SRP-LR Section 3.2.2.2.7 states that loss of material due to general corrosion and fouling may occur on steel drywell and the suppression chamber spray system nozzle and flow orifice internal surfaces exposed to air—indoor uncontrolled and may cause plugging of the spray nozzles and flow orifices.

This item applies to BWR steel drywell and the suppression chamber spray system and is therefore not applicable to IP because IP2 and IP3 are PWRs. On this basis, the staff finds that that SRP-LR Section 3.2.2.2.7 criteria do not apply to IP.

Based on the above, the staff concludes that SRP-LR Section 3.2.2.2.7 criteria do not apply.

3.2.2.2.8 Loss of Material Due to General, Pitting, and Crevice Corrosion

The staff reviewed LRA Section 3.2.2.2.8 against the criteria in SRP-LR Section 3.2.2.2.8.

(1) LRA Section 3.2.2.2.8 addresses loss of material due to general, pitting, and crevice corrosion in BWR steel piping, piping components, and piping elements exposed to

treated water and states that this aging effect is not applicable to IP, which are PWRs.

SRP-LR Section 3.2.2.2.8 states that loss of material due to general, pitting, and crevice corrosion may occur in BWR steel piping, piping components, and piping elements exposed to treated water.

This line item is not applicable to IP because IP2 and IP3 are PWRs. On this basis, the staff finds that the SRP-LR criteria do not apply to IP.

(2) LRA Section 3.2.2.2.8 addresses loss of material due to general, pitting, and crevice corrosion for primary containment penetration steel piping and components exposed to treated water and states that the Water Chemistry Control—Primary and Secondary Program manages this aging effect. The One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control—Primary and Secondary Program by an inspection of a representative sample of components crediting this program, including those in areas of stagnant flow and other susceptible locations.

SRP-LR Section 3.2.2.2.8 states that loss of material due to general, pitting, and crevice corrosion may occur on the internal surfaces of steel containment isolation piping, piping components, and piping elements exposed to treated water. The existing AMP monitors and controls water chemistry to mitigate degradation. However, control of water chemistry does not preclude loss of material due to general, pitting, and crevice corrosion at locations with stagnant flow conditions. Therefore, the effectiveness of water chemistry control programs should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to verify the effectiveness of water chemistry control programs. A one-time inspection of selected components at susceptible locations is an acceptable method to determine whether an aging effect is occurring or is slowly progressing such that the component's intended functions will be maintained during the period of extended operation.

The staff reviewed the Water Chemistry Control—Primary and Secondary Program which monitors chlorides, fluorides, and dissolved oxygen to limit the contaminants and thus minimizes the occurrence of aging effects and maintains component ability to perform intended functions. The applicant has stated that the Water Chemistry Control—Primary and Secondary Program will be verified for effectiveness by the One-Time Inspection Program. The One-time Inspection Program provides inspections of selected steel components exposed to treated water at susceptible locations, such as stagnant areas for loss of material due to general, pitting, and crevice corrosion in applicable ESF systems. The staff evaluated the Water Chemistry Control—Primary and Secondary Program and the One-time Inspection Program and documented the evaluations in SER Sections 3.0.3.2.17 and 3.0.3.1.9, respectively. The staff finds that these programs include activities that are consistent with the recommendations in the GALL Report and are adequate to manage loss of material due to general, pitting, and crevice corrosion on internal surfaces of containment isolation piping and components exposed to treated water.

(3) LRA Section 3.2.2.2.8 addresses loss of material due to general, pitting, and crevice corrosion for steel piping and ESF system components exposed to lubricating oil and states that the Oil Analysis Program manages this aging effect by periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits to preserve

an environment not conducive to corrosion. The One-Time Inspection Program will use visual inspections or NDEs of representative samples to verify that the Oil Analysis Program has been effective in managing aging effects for components crediting this program.

SRP-LR Section 3.2.2.2.8 states that loss of material due to general, pitting, and crevice corrosion may occur in steel piping, piping components, and piping elements exposed to lubricating oil. The existing program periodically samples and analyzes lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment not conducive to corrosion. However, control of lube oil contaminants may not always be fully effective in precluding corrosion. Therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation to verify the effectiveness of lubricating oil programs. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that intended functions of components will be maintained during the period of extended operation.

The staff reviewed the Oil Analysis Program, which monitors oil chemical and physical properties, excessive metal loss caused by wear, contaminants, additives, and water and thus minimizes the occurrence of aging effects and maintains component ability to perform intended functions. The One-Time Inspection Program verifies the effectiveness of the Oil Analysis Program. The One-Time Inspection Program provides inspection of steel piping and components exposed to lubricating oil for loss of material due to general, pitting, and crevice corrosion at susceptible locations where contaminants can accumulate in applicable ESF systems. The staff evaluated the Oil Analysis and the One-Time Inspection Programs and documented the evaluations in SER Sections 3.0.3.2.12 and 3.0.3.1.9, respectively. The staff finds that these programs include activities that are consistent with the recommendations in the GALL Report and are adequate to manage loss of material due to general, pitting, and crevice corrosion in steel piping and components exposed to lubricating oil.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.2.2.2.8 criteria. For those line items that apply to LRA Section 3.2.2.2.8, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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

The staff reviewed LRA Section 3.2.2.2.9 against the criteria in SRP-LR Section 3.2.2.2.9.

LRA Section 3.2.2.2.9 addresses loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion in steel piping (with or without coating or wrapping), piping components, and piping elements buried in soil and states that this aging effect is not applicable because there are no buried carbon steel components in ESF systems with intended functions for license renewal at IP2 or IP3.

SRP-LR Section 3.2.2.2.9 states that loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion may occur in steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil.

In the LRA, the applicant stated that SRP-LR Section 3.2.2.2.9 does not apply to the IP ESF systems because there are no buried carbon steel components in ESF systems with intended functions for license renewal at IP. During the audit and review, the staff verified that there is no buried carbon steel piping associated with the ESF systems at IP. On this basis, the staff finds that SRP-LR Section 3.2.2.2.9 criteria do not apply to IP.

Based on the above, the staff concludes that SRP-LR Section 3.2.2.2.9 criteria do not apply.

3.2.2.2.10 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA program.

3.2A.2.3 IP2 AMR Results Not Consistent with or Not Addressed in the GALL Report

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-IP2 through 3.2.2-5-IP2, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided additional information about how it will manage the aging effects. Specifically, Note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation. The following sections document the staff's evaluation.

3.2A.2.3.1 Residual Heat Removal System - Summary of Aging Management Review – LRA Table 3.2.2-1-IP2

The staff reviewed LRA Table 3.2.2-1-IP2, which summarizes the results of AMR evaluations for the residual heat removal system component groups.

In LRA Table 3.2.2-1-IP2, the applicant proposed to manage reduction of heat transfer in stainless steel HX tube sides exposed to an internal environment of treated borated water by using the Water Chemistry Control—Primary and Secondary Program. The applicant used Note G to indicate that the environment for this component and material is not in the GALL Report.

SER Section 3.0.3.2.17 documents the staff's evaluation of the Water Chemistry Control—Primary and Secondary Program. The staff finds that the Water Chemistry Control—Primary and Secondary Program monitors chlorides, fluorides, and dissolved oxygen to limit the contaminants and thus minimizes the occurrence of aging effects and maintains component ability to perform intended functions. The Water Chemistry Control—Primary and Secondary Program is consistent with the GALL Report, with no exceptions, and in accordance with the latest revision of the EPRI water chemistry guidelines. The applicant also stated that the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Control—Primary and Secondary Program in managing aging effects. On the basis of the review discussed above and the applicant's plant-specific and industry operating experience, the staff finds that the Water Chemistry Control—Primary and Secondary Program will adequately manage the aging effect of fouling in stainless steel HX tube-side components exposed to an internal environment of borated water.

In LRA Table 3.2.2-1-IP2, the applicant proposed to manage loss of material due to wear in stainless steel HX tube sides exposed to an external environment of treated water by using the Heat Exchanger Monitoring Program. The applicant used Note H to indicate that the aging effect for this component and material is not in the GALL Report.

SER Section 3.0.3.3.3 documents the staff's evaluation of the Heat Exchanger Monitoring Program. The staff finds that the Heat Exchanger Monitoring Program includes periodic visual inspection or NDEs to detect loss of material due to wear on the outside tube surfaces. The staff confirms that IP2 RHR HXs and the RHR pump seal coolers are included in the scope of the Heat Exchanger Monitoring Program. On this basis, the staff finds that the aging effect of loss of material due to wear in stainless steel HX tube sides exposed to an external environment of treated water will be adequately managed by using the Heat Exchanger Monitoring Program.

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

3.2A.2.3.2 Containment Spray System - Summary of Aging Management Review – LRA Table 3.2.2-2-IP2

The staff reviewed LRA Table 3.2.2-2-IP2, which summarizes the results of AMR evaluations for the CS system component groups.

In LRA Table 3.2.2-2-IP2, the applicant used Note G and identified no aging effects for the stainless steel flow element, spray nozzles, piping, tubing, and valves exposed to an interior environment of plant indoor air. This line item is similar to Item VF-12 in the GALL Report, which is for stainless steel piping, piping components, and piping elements in an external environment of air—indoor uncontrolled. Because the LRA item is similar to the GALL Report item for that material and environment, the staff finds that the exposure of stainless steel material to plant indoor air will not result in AERMs during the period of extended operation.

In LRA Table 3.2.2-2-IP2, the applicant proposed to manage loss of material in stainless steel piping and valves exposed to an external environment of plant indoor air by using the External Surfaces Monitoring Program. The applicant used Note G to indicate that the environment for this component and material is not in the GALL Report.

The staff finds that the applicant's External Surfaces Monitoring Program performs periodic visual inspections of external surfaces during system engineer walkdowns. These walkdowns are performed at least every refueling outage. SER Section 3.0.3.2.5 documents the staff's evaluation of the External Surfaces Monitoring Program. The staff finds that the aging effect of loss of material in stainless steel piping and valves exposed to an external environment of plant indoor air will be adequately managed by using the External Surfaces Monitoring Program.

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

3.2A.2.3.3 Containment Isolation Support System - Summary of Aging Management Review – LRA Table 3.2.2-3-IP2

The staff reviewed LRA Table 3.2.2-3-IP2, which summarizes the results of AMR evaluations for the containment isolation support system component groups. All AMR results in the table had Notes A through E. The staff's evaluation of these line items is documented in SER Section 3.2.2.1.

On the basis of its review, as documented in SER Section 3.2.2.1, the staff finds that all AMR results described in LRA Table 3.2.2-3-IP3 are consistent with the GALL Report.

3.2A.2.3.4 Safety Injection System - Summary of Aging Management Review – LRA Table 3.2.2-4-IP2

The staff reviewed LRA Table 3.2.2-4-IP2, which summarizes the results of AMR evaluations for the safety injection system component groups.

In LRA Table 3.2.2-4-IP2, the applicant used Note G and identified no aging effects for stainless steel piping, tubing, and valves exposed to an interior environment of plant indoor air. This line item is similar to Item VF-12 in the GALL Report, which is for stainless steel piping, piping components, and piping elements in an external environment of air—indoor uncontrolled. Because the LRA item is similar to the GALL Report item for that material and environment, the staff finds that the exposure of stainless steel material to plant indoor air will not result in aging that will be of concern during the period of extended operation.

In LRA Table 3.2.2-4-IP2, the applicant proposed to manage loss of material in stainless steel piping and tanks exposed to an external environment of outdoor air by using the External Surfaces Monitoring Program. The applicant used Note G to indicate that the environment for this component and material is not in the GALL Report.

The staff finds that the applicant's External Surfaces Monitoring Program performs periodic visual inspections of external surfaces during system engineer walkdowns. SER Section 3.0.3.2.5 documents the staff's evaluation of the External Surfaces Monitoring Program. The staff finds that the aging effect of loss of material in stainless steel piping and tanks exposed to an external environment of outdoor air will be adequately managed by using the

External Surfaces Monitoring Program.

In LRA Table 3.2.2-4-IP2, the applicant proposed to manage fouling in copper alloy HX tubes exposed to an external environment of plant indoor air by using the Periodic Surveillance and Preventive Maintenance Program. The applicant used Note G to indicate that the environment for this component and material is not in the GALL Report.

SER Section 3.0.3.3.7 documents the staff's evaluation of the Periodic Surveillance and Preventive Maintenance Program. The staff finds that the Periodic Surveillance and Preventive Maintenance Program includes periodic inspections and tests of the equipment. The staff confirms that IP2 recirculation pump motor cooling coils are included in the scope of the Periodic Surveillance and Preventive Maintenance Program. On this basis, the staff finds that the aging effect of fouling in copper alloy HX tubes exposed to an external environment of plant indoor air will be adequately managed by using the Periodic Surveillance and Preventive Maintenance Program.

In LRA Table 3.2.2-1-IP2, the applicant proposed to manage loss of material due to wear in stainless steel HX tube sides exposed to an external environment of treated water by using the Heat Exchanger Monitoring Program. The applicant used Note H to indicate that the aging effect for this component and material is not in the GALL Report.

SER Section 3.0.3.3.3 documents the staff's evaluation of the Heat Exchanger Monitoring Program. The staff finds that the Heat Exchanger Monitoring Program includes periodic visual inspection or NDEs to detect loss of material due to wear on the outside tube surfaces. The staff confirms that IP2 RHR HXs and the RHR pump seal coolers are included in the scope of the Heat Exchanger Monitoring Program. On this basis, the staff finds that the aging effect of loss of material due to wear in stainless steel HX tube sides exposed to an external environment of treated water will be adequately managed by using the Heat Exchanger Monitoring Program.

In LRA Table 3.2.2-4-IP2, the applicant used Note G and identified no aging effects for stainless steel piping, tubing, and valve bodies in the safety injection system exposed to air—indoor internal environments. The applicant did not credit any AMPs for these component, material, and environment combinations because it concluded that there are no AERMs for these components exposed to air—indoor internal environments.

The staff verified that, although the GALL Report does not include AMR items for aging of stainless steel components exposed to air—indoor environments, the report does include AMR Item V.F-12 with an AMR for stainless steel piping components exposed to external air—indoor environments and the position that there are no AERMs for stainless steel components exposed to such environments. The staff verified that no operating experience implies that stainless steel component surfaces exposed to air—indoor environments have no AERMs. Thus, the staff finds it valid to conclude that there are no AERMs for the surfaces of stainless steel piping, tubing, and valve bodies exposed to air—indoor internal environments. On the basis of this finding, the staff concludes that the applicant need not credit any AMPs for these component, environment, material, and aging effect combinations.

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

3.2A.2.3.5 Containment Penetrations - Summary of Aging Management Review – LRA Table 3.2.2-5-IP2

The staff reviewed LRA Table 3.2.2-5-IP2, which summarizes the results of AMR evaluations for the containment penetrations component groups.

In LRA Table 3.2.2-5-IP2, the applicant used Note G and identified no aging effects for the stainless steel flow element, piping, regulator, sampler housing, tubing, and valves exposed to an interior environment of plant indoor air. These line items are similar to Item VF-12 in the GALL Report, which is for stainless steel piping, piping components, and piping elements in an external environment of air—indoor uncontrolled. Because the LRA item is similar to the GALL Report item for that material and environment, the staff finds that the exposure of stainless steel material to plant indoor air will not result in aging that will be of concern during the period of extended operation.

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

3.2B.2.3 IP3 AMR Results Not Consistent with or Not Addressed in the GALL Report

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-IP3 through 3.2.2-5-IP3, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided additional information about how it will manage the aging effects. Specifically, Note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation. The following sections document the staff's evaluation.

3.2B.2.3.1 Residual Heat Removal System - Summary of Aging Management Review – LRA Table 3.2.2-1-IP3

The staff reviewed LRA Table 3.2.2-1-IP3, which summarizes the results of AMR evaluations for the residual heat removal system component groups.

In LRA Table 3.2.2-1-IP3, the applicant proposed to manage reduction of heat transfer in stainless steel HX tube sides exposed to an internal environment of treated borated water by using the Water Chemistry Control—Primary and Secondary Program. The applicant used Note G to indicate that the environment for this component and material is not in the GALL Report.

SER Section 3.0.3.2.17 documents the staff's evaluation of the Water Chemistry Control—Primary and Secondary Program. The staff finds that the Water Chemistry Control—Primary and Secondary Program monitors chlorides, fluorides, and dissolved oxygen to limit the contaminants and thus minimizes the occurrence of aging effects and maintains component ability to perform its intended functions. The Water Chemistry Control—Primary and Secondary Program is consistent with the GALL Report, with no exceptions, and in accordance with the latest revision of the EPRI water chemistry guidelines. The applicant also stated that the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Control—Primary and Secondary Program in managing aging effects. On the basis of the review discussed above and the applicant's plant-specific and industry operating experience, the staff finds that the Water Chemistry Control—Primary and Secondary Program will adequately manage the aging effect of fouling in stainless steel HX tube side components exposed to an internal environment of borated water.

In LRA Table 3.2.2-1-IP3, the applicant proposed to manage loss of material due to wear in stainless steel HX tube sides exposed to an external environment of treated water by using the Heat Exchanger Monitoring Program. The applicant used Note H to indicate that the aging effect for this component and material is not in the GALL Report.

SER Section 3.0.3.3.3 documents the staff's evaluation of the Heat Exchanger Monitoring Program. The staff finds that the Heat Exchanger Monitoring Program includes periodic visual inspection or NDEs to detect loss of material due to wear on the outside tube surfaces. The staff confirmed that IP3 RHR HXs and the RHR pump seal coolers are included in the scope of the Heat Exchanger Monitoring Program. On this basis, the staff finds that the aging effect of loss of material due to wear in stainless steel HX tube sides exposed to an external environment of treated water will be adequately managed by using the Heat Exchanger Monitoring Program.

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

3.2B.2.3.2 Containment Spray System - Summary of Aging Management Review – LRA Table 3.2.2-2-IP3

The staff reviewed LRA Table 3.2.2-2-IP3, which summarizes the results of AMR evaluations for the containment spray system component groups.

During the audit, the staff noted that for IP3 on LRA pages 3.2-48 to 3.2-51, 11 line items reference Note G and the plant-specific Note 202. Note G states that the GALL Report does not include the environment for this component and material. Note 202 states that the treated water environment contains sodium hydroxide. The staff asked the applicant to explain how the AMPs listed in each line item will manage the aging effects for the material and environment for the specified component (Audit Item 356).

In its response dated December 18, 2007, the applicant stated the following:

> Per audit items 90 and 91, components exposed to sodium hydroxide are managed by the Periodic Surveillance and Preventive Maintenance Program. The LRA line items in Table 3.2.2-2-IP3 will be revised to replace the Water Chemistry Control – Auxiliary Systems with Periodic Surveillance and Preventive Maintenance (PSPM) Program as the aging management program for components with Notes G and 202.
>
> The PSPM Program will perform visual or other NDE inspections on the inside surfaces of a representative sample of stainless steel components exposed to sodium hydroxide once every five years to manage loss of material and cracking.
>
> Clarification to be incorporated into the LRA.

By letter dated June 30, 2009, the applicant submitted an annual update to the LRA, identifying changes made to the CLB that materially affect the contents of the LRA. As a result of an engineering change, the applicant modified the buffer chemical in the containment spray system from sodium hydroxide (liquid injection) to sump baskets containing sodium tetraborate. The AMR line items affected by this change are those discussed above in the response to the audit questions. The applicant stated that the sodium hydroxide injection components are retired in place and are disconnected and drained. The applicant further stated that the sump baskets have no license renewal intended function and are not in scope for license renewal. The staff determined that these components no longer have an intended function that meets any of the criteria in 10 CFR 54.4(a). Therefore, the staff finds that the removal of the components from the scope of license renewal is acceptable.

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

3.2B.2.3.3 Containment Isolation Support System - Summary of Aging Management Review – LRA Table 3.2.2-3-IP3

The staff reviewed LRA Table 3.2.2-3-IP3, which summarizes the results of AMR evaluations for the containment isolation support system component groups. All AMR results in the table had Notes A through E. The staff's evaluation of these line items is documented in SER Section 3.2.2.1.

On the basis of its review, as documented in SER Section 3.2.2.1, the staff finds that all AMR results described in LRA Table 3.2.2-3-IP3 are consistent with the GALL Report.

3.2B.2.3.4 Safety Injection System - Summary of Aging Management Review – LRA Table 3.2.2-4-IP3

The staff reviewed LRA Table 3.2.2-4-IP3, which summarizes the results of AMR evaluations for the safety injection system component groups.

In LRA Table 3.2.2-4-IP3, the applicant used Note G and identified no aging effects for stainless steel piping, tubing, and valves exposed to an interior environment of plant indoor air. This line item is similar to Item VF-12 in the GALL Report, which is for stainless steel piping, piping components, and piping elements in an external environment of air—indoor uncontrolled. Because the LRA item is similar to the GALL Report item for that material and environment, the staff finds that the exposure of stainless steel material to plant indoor air will not result in aging that will be of concern during the period of extended operation.

In LRA Table 3.2.2-4-IP3, the applicant proposed to manage loss of material in stainless steel piping and tanks exposed to an external environment of outdoor air by using the External Surfaces Monitoring Program. The applicant used Note G to indicate that the environment for this component and material is not in the GALL Report.

The staff finds that the applicant's External Surfaces Monitoring Program performs periodic visual inspections of external surfaces during system engineer walkdowns. SER Section 3.0.3.2.5 documents the staff's evaluation of the External Surfaces Monitoring Program. The staff finds that the aging effect of loss of material in stainless steel piping and tanks exposed to an external environment of outdoor air will be adequately managed by using the External Surfaces Monitoring Program.

In LRA Table 3.2.2-4-IP3, the applicant proposed to manage fouling in copper alloy HX tubes exposed to an external environment of plant indoor air by using the Periodic Surveillance and Preventive Maintenance Program. The applicant used Note G to indicate that the environment for this component and material is not in the GALL Report.

SER Section 3.0.3.3.7 documents the staff's evaluation of the Periodic Surveillance and Preventive Maintenance Program. The staff finds that the Periodic Surveillance and Preventive Maintenance Program includes periodic inspections and tests of the equipment. The staff confirmed that IP3 recirculation pump motor cooling coils are included in the scope of the Periodic Surveillance and Preventive Maintenance Program. On this basis, the staff finds that the aging effect of fouling in copper alloy HX tubes exposed to an external environment of plant indoor air will be adequately managed by using the Periodic Surveillance and Preventive Maintenance Program.

In LRA Table 3.2.2-1-IP3, the applicant proposed to manage loss of material due to wear in stainless steel HX tube sides exposed to an external environment of treated water by using the Heat Exchanger Monitoring Program. The applicant used Note H to indicate that the aging effect for this component and material is not in the GALL Report.

SER Section 3.0.3.3.3 documents the staff's evaluation of the Heat Exchanger Monitoring Program. The staff finds that the Heat Exchanger Monitoring Program includes periodic visual inspection or NDEs to detect loss of material due to wear on the outside tube surfaces. The staff confirmed that IP3 RHR HXs and the RHR pump seal coolers are included in the scope of the Heat Exchanger Monitoring Program. On this basis, the staff finds that the aging effect of loss of material due to wear in copper alloy HX tube sides exposed to an external environment of lube oil will be adequately managed by using the Heat Exchanger Monitoring Program.

In LRA Table 3.2.2-4-IP3, the applicant used Note G and identified no aging effects for stainless steel piping, tubing, and valve bodies in the safety injection system exposed to air—indoor internal environments. The applicant did not credit any AMPs for these components, material, and environment combinations because it concluded that there are no AERMs for these components exposed to air—indoor internal environments.

The staff verified that, although the GALL Report does not include AMR items on aging of stainless steel components exposed to air—indoor environments, the report does include AMR Item V.F-12 with an AMR for stainless steel piping components exposed to external air—indoor environments and the position that there are no AERMs for stainless steel components exposed to such environments. The staff verified that no operating experience implies that stainless steel component surfaces exposed to air—indoor environments have no AERMs. Thus, the staff finds it valid to conclude that there are no AERMs for surfaces of stainless steel piping, tubing, and valve bodies exposed to air—indoor internal environments. On the basis of this finding, the staff concludes that the applicant need not credit any AMPs for these component, environment, material, and aging effect combinations.

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

3.2B.2.3.5 Containment Penetrations - Summary of Aging Management Review – LRA Table 3.2.2-5-IP3

The staff reviewed LRA Table 3.2.2-5-IP3, which summarizes the results of AMR evaluations for the containment penetrations component groups.

In LRA Table 3.2.2-5-IP3, the applicant used Note G and identified no aging effects for the stainless steel flow element, piping, regulator, sampler housing, tubing, and valves exposed to an interior environment of plant indoor air. This line item is similar to Item VF-12 in the GALL Report, which is for stainless steel piping, piping components, and piping elements in an external environment of air—indoor uncontrolled. Because the LRA item is similar to the GALL Report item for that material and environment, the staff finds that the exposure of stainless steel material to plant indoor air will not result in aging that will be of concern during the period of extended operation.

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

3.2.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the ESF system components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3 Aging Management of Auxiliary Systems

This section of the SER documents the staff's review of the applicant's AMR results for the following auxiliary systems components and component groups of:

- spent fuel pit cooling
- SW
- CCW
- compressed air
- nitrogen
- chemical and volume control
- primary makeup water
- HVAC
- containment cooling and filtration
- control room HVAC
- fire protection—water
- fire protection—CO_2, Halon, and RCP oil collection systems
- fuel oil
- EDG
- security generator
- Appendix R diesel generators
- city water
- plant drains
- miscellaneous systems in scope for 10 CFR 54.4(a)(2)
-

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 for Auxiliary Systems Evaluated in Chapter VII of NUREG-1801," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the auxiliary 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 CRs and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.3.2 Staff Evaluation

The staff reviewed LRA Section 3.3 to determine whether the applicant had provided sufficient information to demonstrate that the effects of aging for the auxiliary systems components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff conducted an onsite audit of AMRs to verify the applicant's claim that certain AMRs are consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA is applicable and that the applicant identified the appropriate GALL Report AMRs. SER Section 3.0.3 documents the staff's evaluations of the AMPs. SER Section 3.3.2.1 presents details of the staff's evaluation.

In the onsite audit, the staff also selected AMRs consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations are consistent with the SRP-LR Section 3.3.2.2 acceptance criteria. SER Section 3.3.2.2 documents the staff's evaluations.

The staff also conducted a technical review of the remaining AMRs not consistent with or not addressed in the GALL Report. The technical review evaluated whether all plausible aging effects have been identified and whether the aging effects listed are appropriate for the combinations of material and environment specified. SER Sections 3.3A.2.3 (for IP2) and 3.3B.2.3 (for IP3) document the staff's evaluations.

For components that the applicant claimed are not applicable or require no aging management, the staff reviewed the AMR line items and the plant's operating experience to verify the applicant's claims.

Table 3.3-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.3 and addressed in the GALL Report.

Table 3.3-1 Staff Evaluation for Auxiliary System Components in the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel cranes - structural girders exposed to air - indoor uncontrolled (external) (3.3.1-1)	Cumulative fatigue damage	TLAA to be evaluated for structural girders of cranes. See the SRP-LR, Section 4.7 for generic guidance for meeting the requirements of 10 CFR 54.21(c)(1).	Yes	TLAA	Consistent with GALL Report (see SER Section 3.3.2.2.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel and stainless steel piping, piping components, piping elements, and heat exchanger components exposed to air - indoor uncontrolled, treated borated water or treated water (3.3.1-2)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Consistent with GALL Report (see SER Section 3.3.2.2.1)
Stainless steel heat exchanger tubes exposed to treated water (3.3.1-3)	Reduction of heat transfer due to fouling	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable (see SER Section 3.3.2.2.2)
Stainless steel piping, piping components, and piping elements exposed to sodium pentaborate solution > 60°C (> 140°F) (3.3.1-4)	Cracking due to SCC	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.2.3(1))
Stainless steel and stainless clad steel heat exchanger components exposed to treated water > 60°C (> 140°F) (3.3.1-5)	Cracking due to SCC	A plant specific AMP is to be evaluated.	Yes	Not applicable	Not Applicable (see SER Section 3.3.2.2.3(2))
Stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust (3.3.1-6)	Cracking due to SCC	A plant specific AMP is to be evaluated.	Yes	Not applicable	Not Applicable (see SER Section 3.3.2.2.3(3))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel non-regenerative heat exchanger components exposed to treated borated water > 60°C (> 140°F) (3.3.1-7)	Cracking due to SCC and cyclic loading	Water Chemistry and a plant-specific verification program. An acceptable verification program is to include temperature and radioactivity monitoring of the shell side water, and eddy current testing of tubes.	Yes	Water Chemistry Control – Primary and Secondary, and One Time Inspection	Consistent with GALL Report (see SER Section 3.3.2.2.4(1))
Stainless steel regenerative heat exchanger components exposed to treated borated water > 60°C (> 140°F) (3.3.1-8)	Cracking due to SCC and cyclic loading	Water Chemistry and a plant-specific verification program. The AMP is to be augmented by verifying the absence of cracking due to SCC and cyclic loading. A plant specific AMP is to be evaluated.	Yes	Water Chemistry Control – Primary and Secondary , and One Time Inspection Program	Consistent with GALL Report (see SER Section 3.3.2.2.4(2))
Stainless steel high-pressure pump casing in PWR chemical and volume control system (3.3.1-9)	Cracking due to SCC and cyclic loading	Water Chemistry and a plant-specific verification program. The AMP is to be augmented by verifying the absence of cracking due to SCC and cyclic loading. A plant specific AMP is to be evaluated.	Yes	Water Chemistry Control – Primary and Secondary	Consistent with GALL Report (see SER Section 3.3.2.2.4(3))
High-strength steel closure bolting exposed to air with steam or water leakage. (3.3.1-10)	Cracking due to SCC, cyclic loading	Bolting Integrity. The AMP is to be augmented by appropriate inspection to detect cracking if the bolts are not otherwise replaced during maintenance.	Yes	Not applicable	Not applicable. High strength steel bolting is not used in the auxiliary systems.
Elastomer seals and components exposed to air - indoor uncontrolled (internal/external) (3.3.1-11)	Hardening and loss of strength due to elastomer degradation	A plant specific AMP is to be evaluated.	Yes	Periodic Surveillance and Preventive Maintenance	Consistent with GALL Report (see SER Section 3.3.2.2.5(1))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Elastomer lining exposed to treated water or treated borated water (3.3.1-12)	Hardening and loss of strength due to elastomer degradation	A plant-specific AMP is to be evaluated.	Yes	Periodic Surveillance and Preventive Maintenance	Consistent with GALL Report (see SER Section 3.3.2.2.5(2))
Boral, boron steel spent fuel storage racks neutron-absorbing sheets exposed to treated water or treated borated water (3.3.1-13)	Reduction of neutron-absorbing capacity and loss of material due to general corrosion	A plant specific AMP is to be evaluated.	Yes	Boral Surveillance, and Water Chemistry Control – Primary and Secondary	Consistent with GALL Report (see SER Section 3.3.2.2.6)
Steel piping, piping component, and piping elements exposed to lubricating oil (3.3.1-14)	Loss of material due to general, pitting, and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	Oil Analysis, and One-Time Inspection	Consistent with GALL Report (see SER Section 3.3.2.2.7(1))
Steel reactor coolant pump oil collection system piping, tubing, and valve bodies exposed to lubricating oil (3.3.1-15)	Loss of material due to general, pitting, and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	Oil Analysis, and One-Time Inspection	Consistent with GALL Report (see SER Section 3.3.2.2.7(1))
Steel reactor coolant pump oil collection system tank exposed to lubricating oil (3.3.1-16)	Loss of material due to general, pitting, and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection to evaluate the thickness of the lower portion of the tank	Yes	Oil Analysis, and One-Time Inspection	Consistent with GALL Report (see SER Section 3.3.2.2.7(1))
Steel piping, piping components, and piping elements exposed to treated water (3.3.1-17)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.2.7(2))
Stainless steel and steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust (3.3.1-18)	Loss of material/general (steel only), pitting and crevice corrosion	A plant specific AMP is to be evaluated.	Yes	Periodic Surveillance and Preventive Maintenance, One-Time Inspection, and Fire Protection	Consistent with GALL Report (see SER Section 3.3.2.2.7(3))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel (with or without coating or wrapping) piping, piping components, and piping elements exposed to soil (3.3.1-19)	Loss of material due to general, pitting, crevice, and microbiologically -influenced corrosion	Buried Piping and Tanks Surveillance or Buried Piping and Tanks Inspection	No Yes	Buried Piping and Tanks Inspection	Consistent with GALL Report (see SER Section 3.3.2.2.8)
Steel piping, piping components, piping elements, and tanks exposed to fuel oil (3.3.1-20)	Loss of material due to general, pitting, crevice, and microbiologically -influenced corrosion, and fouling	Fuel Oil Chemistry and One-Time Inspection	Yes	Fuel Oil Chemistry. and One-Time Inspection	Consistent with GALL Report (see SER Section 3.3.2.2.9(1))
Steel heat exchanger components exposed to lubricating oil (3.3.1-21)	Loss of material due to general, pitting, crevice, and microbiologically -influenced corrosion, and fouling	Lubricating Oil Analysis and One-Time Inspection	Yes	Oil Analysis, and One-Time Inspection	Consistent with GALL Report (see SER Section 3.3.2.2.9(2))
Steel with elastomer lining or stainless steel cladding piping, piping components, and piping elements exposed to treated water and treated borated water (3.3.1-22)	Loss of material due to pitting and crevice corrosion (only for steel after lining/cladding degradation)	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.2.10(1))
Stainless steel and steel with stainless steel cladding heat exchanger components exposed to treated water (3.3.1-23)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.2.10(2))
Stainless steel and aluminum piping, piping components, and piping elements exposed to treated water (3.3.1-24)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry, and One-Time Inspection	Consistent with GALL Report (see SER Section 3.3.2.2.10(2))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper alloy HVAC piping, piping components, piping elements exposed to condensation (external) (3.3.1-25)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	External Surfaces Monitoring, and Periodic Surveillance and Preventive Maintenance	Consistent with GALL Report (see SER Section 3.3.2.2.10(3))
Copper alloy piping, piping components, and piping elements exposed to lubricating oil (3.3.1-26)	Loss of material due to pitting and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	Oil Analysis, and One-Time Inspection	Consistent with GALL Report (see SER Section 3.3.2.2.10(4))
Stainless steel HVAC ducting and aluminum HVAC piping, piping components and piping elements exposed to condensation (3.3.1-27)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Bolting Integrity, External Surfaces Monitoring, Periodic Surveillance and Preventive Maintenance, and One-Time Inspection	Consistent with GALL Report (see SER Section 3.3.2.2.10(5))
Copper alloy fire protection piping, piping components, and piping elements exposed to condensation (internal) (3.3.1-28)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Periodic Surveillance and Preventive Maintenance	Consistent with GALL Report (see SER Section 3.3.2.2.10(6))
Stainless steel piping, piping components, and piping elements exposed to soil (3.3.1-29)	Loss of material due to pitting and crevice corrosion	A plant-specific AMP is to be evaluated.	Yes	Not applicable	Not applicable. There are no buried stainless steel components in the auxiliary systems. (see SER Section 3.3.2.2.10(7))
Stainless steel piping, piping components, and piping elements exposed to sodium pentaborate solution (3.3.1-30)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.2.10(8))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper alloy piping, piping components, and piping elements exposed to treated water (3.3.1-31)	Loss of material due to pitting, crevice, and galvanic corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.2.11)
Stainless steel, aluminum and copper alloy piping, piping components, and piping elements exposed to fuel oil (3.3.1-32)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion	Fuel Oil Chemistry and One-Time Inspection	Yes	Diesel Fuel Monitoring, One-Time Inspection, Periodic Surveillance and Preventive Maintenance	Consistent with GALL Report (see SER Section 3.3.2.2.12(1))
Stainless steel piping, piping components, and piping elements exposed to lubricating oil (3.3.1-33)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	Oil Analysis, and One-Time Inspection	Consistent with GALL Report (see SER Section 3.3.2.2.12(2))
Elastomer seals and components exposed to air - indoor uncontrolled (internal or external) (3.3.1-34)	Loss of material due to wear	A plant specific AMP is to be evaluated.	Yes	Not applicable	Not applicable (see SER Section 3.3.2.2.13)
Steel with stainless steel cladding pump casing exposed to treated borated water (3.3.1-35)	Loss of material due to cladding breach	A plant-specific AMP is to be evaluated. Reference NRC IN 94-63, "Boric Acid Corrosion of Charging Pump Casings Caused by Cladding Cracks."	Yes	Not applicable	Not applicable (see SER Section 3.3.2.2.14)
Boraflex spent fuel storage racks neutron-absorbing sheets exposed to treated water (3.3.1-36)	Reduction of neutron-absorbing capacity due to boraflex degradation	Boraflex Monitoring	No	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to treated water > 60°C (> 140°F) (3.3.1-37)	Cracking due to SCC, intergranular SCC	BWR Reactor Water Cleanup System	No	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel piping, piping components, and piping elements exposed to treated water > 60°C (> 140°F) (3.3.1-38)	Cracking due to SCC	BWR SCC and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.1.1)
Stainless steel BWR spent fuel storage racks exposed to treated water > 60°C (> 140°F) (3.3.1-39)	Cracking due to SCC	Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.3.2.1.1)
Steel tanks in diesel fuel oil system exposed to air - outdoor (external) (3.3.1-40)	Loss of material due to general, pitting, and crevice corrosion	Aboveground Steel Tanks	No	Aboveground Steel Tanks	Consistent with GALL Report
High-strength steel closure bolting exposed to air with steam or water leakage (3.3.1-41)	Cracking due to cyclic loading, SCC	Bolting Integrity	No	Not applicable	Not applicable. High-strength steel closure bolting is not used in the auxiliary systems (see SER Section 3.3.2.1.1)
Steel closure bolting exposed to air with steam or water leakage (3.3.1-42)	Loss of material due to general corrosion	Bolting Integrity	No	Not applicable	Not applicable. This line item was not used. Loss of material of steel closure bolting was addressed by other items including 3.3.1-43, 3.3.1-44 and 3.3.1-55 (see SER Section 3.3.2.1.2)
Steel bolting and closure bolting exposed to air - indoor uncontrolled (external) or air - outdoor (external) (3.3.1-43)	Loss of material due to general, pitting, and crevice corrosion	Bolting Integrity	No	Bolting Integrity	Consistent with GALL Report
Steel compressed air system closure bolting exposed to condensation (3.3.1-44)	Loss of material due to general, pitting, and crevice corrosion	Bolting Integrity	No	Bolting Integrity	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel closure bolting exposed to air - indoor uncontrolled (external) (3.3.1-45)	Loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	No	Bolting Integrity	Consistent with GALL Report (See SER Section 3.3.2.1.4)
Stainless steel and stainless clad steel piping, piping components, piping elements, and heat exchanger components exposed to closed cycle cooling water > 60°C (> 140°F) (3.3.1-46)	Cracking due to SCC	Closed-Cycle Cooling Water System	No	Water Chemistry Control – Closed Cooling Water, and One-Time Inspection for Water Chemistry	Consistent with GALL Report
Steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to closed cycle cooling water (3.3.1-47)	Loss of material due to general, pitting, and crevice corrosion	Closed-Cycle Cooling Water System	No	Water Chemistry Control – Closed Cooling Water, and One-Time Inspection for Water Chemistry	Consistent with GALL Report
Steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to closed cycle cooling water (3.3.1-48)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	No	Water Chemistry Control – Closed Cooling Water	Consistent with GALL Report
Stainless steel; steel with stainless steel cladding heat exchanger components exposed to closed cycle cooling water (3.3.1-49)	Loss of material due to microbiologically -influenced corrosion	Closed-Cycle Cooling Water System	No	Water Chemistry Control – Closed Cooling Water	Consistent with GALL Report
Stainless steel piping, piping components, and piping elements exposed to closed cycle cooling water (3.3.1-50)	Loss of material due to pitting and crevice corrosion	Closed-Cycle Cooling Water System	No	Water Chemistry Control – Closed Cooling Water, and One-Time Inspection for Water Chemistry	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper alloy piping, piping components, piping elements, and heat exchanger components exposed to closed cycle cooling water (3.3.1-51)	Loss of material due to pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	No	Water Chemistry Control – Closed Cooling Water, and One-Time Inspection for Water Chemistry	Consistent with GALL Report
Steel, stainless steel, and copper alloy heat exchanger tubes exposed to closed cycle cooling water (3.3.1-52)	Reduction of heat transfer due to fouling	Closed-Cycle Cooling Water System	No	Water Chemistry Control – Closed Cooling Water, and One-Time Inspection for Water Chemistry	Consistent with GALL Report
Steel compressed air system piping, piping components, and piping elements exposed to condensation (internal) (3.3.1-53)	Loss of material due to general and pitting corrosion	Compressed Air Monitoring	No	Periodic Surveillance and Preventive Maintenance	See SER Section 3.3.2.1.3
Stainless steel compressed air system piping, piping components, and piping elements exposed to internal condensation (3.3.1-54)	Loss of material due to pitting and crevice corrosion	Compressed Air Monitoring	No	One-Time Inspection	See SER Section 3.3.2.1.3
Steel ducting closure bolting exposed to air - indoor uncontrolled (external) (3.3.1-55)	Loss of material due to general corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring	Consistent with GALL Report
Steel HVAC ducting and components external surfaces exposed to air - indoor uncontrolled (external) (3.3.1-56)	Loss of material due to general corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring, and Periodic Surveillance and Preventive Maintenance	Consistent with GALL Report
Steel piping and components external surfaces exposed to air - indoor uncontrolled (External) (3.3.1-57)	Loss of material due to general corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel external surfaces exposed to air - indoor uncontrolled (external), air - outdoor (external), and condensation (external) (3.3.1-58)	Loss of material due to general corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring, Fire Protection, and Periodic Surveillance and Preventive Maintenance	Consistent with GALL Report
Steel heat exchanger components exposed to air - indoor uncontrolled (external) or air - outdoor (external) (3.3.1-59)	Loss of material due to general, pitting, and crevice corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring, and Periodic Surveillance and Preventive Maintenance	Consistent with GALL Report
Steel piping, piping components, and piping elements exposed to air - outdoor (external) (3.3.1-60)	Loss of material due to general, pitting, and crevice corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring	Consistent with GALL Report
Elastomer fire barrier penetration seals exposed to air - outdoor or air - indoor uncontrolled (3.3.1-61)	Increased hardness, shrinkage and loss of strength due to weathering	Fire Protection	No	Fire Protection	This line item was not used for auxiliary systems. (See SER Section 3.3.2.1.1)
Aluminum piping, piping components, and piping elements exposed to raw water (3.3.1-62)	Loss of material due to pitting and crevice corrosion	Fire Protection	No	One-Time Inspection, and Service Water Integrity	The components to which this line item applies are included in scope under criterion 10 CFR 54.4(a)(2) and are listed in series 3.3.2-19-xx tables. (See SER Section 3.3.2.1.6)
Steel fire rated doors exposed to air - outdoor or air - indoor uncontrolled (3.3.1-63)	Loss of material due to wear	Fire Protection	No	Fire Protection	This line item was not used for auxiliary systems. (See SER Section 3.3.2.1.1
Steel piping, piping components, and piping elements exposed to fuel oil (3.3.1-64)	Loss of material due to general, pitting, and crevice corrosion	Fire Protection and Fuel Oil Chemistry	No	Fire Protection, and Diesel Fuel Monitoring	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Reinforced concrete structural fire barriers - walls, ceilings and floors exposed to air - indoor uncontrolled (3.3.1-65)	Concrete cracking and spalling due to aggressive chemical attack, and reaction with aggregates	Fire Protection and Structures Monitoring Program	No	Fire Protection, and Structures Monitoring	This line item was not used for auxiliary systems. (See SER Section 3.3.2.1.1)
Reinforced concrete structural fire barriers - walls, ceilings and floors exposed to air - outdoor (3.3.1-66)	Concrete cracking and spalling due to freeze thaw, aggressive chemical attack, and reaction with aggregates	Fire Protection and Structures Monitoring Program	No	Fire Protection, and Structures Monitoring	This line item was not used for auxiliary systems. Reinforced concrete structural fire barriers are evaluated as structural components in Section 3.5 of the LRA.
Reinforced concrete structural fire barriers - walls, ceilings and floors exposed to air - outdoor or air - indoor uncontrolled (3.3.1-67)	Loss of material due to corrosion of embedded steel	Fire Protection and Structures Monitoring Program	No	Fire Protection, and Structures Monitoring	This line item was not used for auxiliary systems. (See SER Section 3.3.2.1.1)
Steel piping, piping components, and piping elements exposed to raw water (3.3.1-68)	Loss of material due to general, pitting, crevice, and microbiologically -influenced corrosion, and fouling	Fire Water System	No	Fire Water System	Consistent with GALL Report
Stainless steel piping, piping components, and piping elements exposed to raw water (3.3.1-69)	Loss of material due to pitting and crevice corrosion, and fouling	Fire Water System	No	Fire Water System	Consistent with GALL Report
Copper alloy piping, piping components, and piping elements exposed to raw water (3.3.1-70)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion, and fouling	Fire Water System	No	Fire Water System	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to moist air or condensation (internal) (3.3.1-71)	Loss of material due to general, pitting, and crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Periodic Surveillance and Preventive Maintenance	See SER Section 3.3.2.1.6
Steel HVAC ducting and components internal surfaces exposed to condensation (internal) (3.3.1-72)	Loss of material due to general, pitting, crevice, and (for drip pans and drain lines) microbiologically -influenced corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Periodic Surveillance and Preventive Maintenance, and External Surfaces Monitoring	See SER Section 3.3.2.1.7
Steel crane structural girders in load handling system exposed to air - indoor uncontrolled (external) (3.3.1-73)	Loss of material due to general corrosion	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	No	Periodic Surveillance and Preventive Maintenance, and Structures Monitoring	This line item was not used in the auxiliary systems tables. (See SER Section 3.3.2.1.1)
Steel cranes - rails exposed to air - indoor uncontrolled (external) (3.3.1-74)	Loss of material due to Wear	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	No	Periodic Surveillance and Preventive Maintenance, and Structures Monitoring	This line item was not used. Steel crane rails are evaluated as structural components in Section 3.5.
Elastomer seals and components exposed to raw water (3.3.1-75)	Hardening and loss of strength due to elastomer degradation; loss of material due to erosion	Open-Cycle Cooling Water System	No	Periodic Surveillance and Preventive Maintenance	The components to which this line item applies are included in scope under criterion 10 CFR 54.4(a)(2) and are listed in series 3.3.2-19-xx tables in systems other than service water. (See SER Section 3.3.2.1.5)
Steel piping, piping components, and piping elements (without lining/ coating or with degraded lining/coating) exposed to raw water (3.3.1-76)	Loss of material due to general, pitting, crevice, and microbiologically -influenced corrosion, fouling, and lining/coating degradation	Open-Cycle Cooling Water System	No	Service Water Integrity Program, and Periodic Surveillance and Preventive Maintenance	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel heat exchanger components exposed to raw water (3.3.1-77)	Loss of material due to general, pitting, crevice, galvanic, and microbiologically -influenced corrosion, and fouling	Open-Cycle Cooling Water System	No	Service Water Integrity	Consistent with GALL Report
Stainless steel, nickel alloy, and copper alloy piping, piping components, and piping elements exposed to raw water (3.3.1-78)	Loss of material due to pitting and crevice corrosion	Open-Cycle Cooling Water System	No	Service Water Integrity	Consistent with GALL Report. Stainless steel and copper alloy components exposed to raw water are addressed in other items including 3.3.1-79 and 3.3.1-81.
Stainless steel piping, piping components, and piping elements exposed to raw water (3.3.1-79)	Loss of material due to pitting and crevice corrosion, and fouling	Open-Cycle Cooling Water System	No	Service Water Integrity, and One-Time Inspection	Consistent with GALL Report
Stainless steel and copper alloy piping, piping components, and piping elements exposed to raw water (3.3.1-80)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion	Open-Cycle Cooling Water System	No	Service Water Integrity	Consistent with GALL Report
Copper alloy piping, piping components, and piping elements, exposed to raw water (3.3.1-81)	Loss of material due to pitting, crevice, and microbiologically -influenced corrosion, and fouling	Open-Cycle Cooling Water System	No	Service Water Integrity	Consistent with GALL Report
Copper alloy heat exchanger components exposed to raw water (3.3.1-82)	Loss of material due to pitting, crevice, galvanic, and microbiologically -influenced corrosion, and fouling	Open-Cycle Cooling Water System	No	Service Water Integrity	Consistent with GALL Report
Stainless steel and copper alloy heat exchanger tubes exposed to raw water (3.3.1-83)	Reduction of heat transfer due to fouling	Open-Cycle Cooling Water System	No	Service Water Integrity	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper alloy > 15% Zn piping, piping components, piping elements, and heat exchanger components exposed to raw water, treated water, or closed cycle cooling water (3.3.1-84)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Selective Leaching	Consistent with GALL Report
Gray cast iron piping, piping components, and piping elements exposed to soil, raw water, treated water, or closed-cycle cooling water (3.3.1-85)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Selective Leaching	Consistent with GALL Report
Structural steel (new fuel storage rack assembly) exposed to air - indoor uncontrolled (external) (3.3.1-86)	Loss of material due to general, pitting, and crevice corrosion	Structures Monitoring Program	No	Not applicable to auxiliary systems.	This line item was not used. Structural steel of the new fuel storage rack assembly is evaluated as a structural component in Section 3.5. (See SER Section 3.3.2.1.1)
Boraflex spent fuel storage racks neutron-absorbing sheets exposed to treated borated water (3.3.1-87)	Reduction of neutron-absorbing capacity due to boraflex degradation	Boraflex Monitoring	No	Boraflex Monitoring, and Water Chemistry Control – Primary and Secondary	Consistent with GALL Report
Aluminum and copper alloy > 15% Zn piping, piping components, and piping elements exposed to air with borated water leakage (3.3.1-88)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	No	Boric Acid Corrosion Prevention	Consistent with GALL Report
Steel bolting and external surfaces exposed to air with borated water leakage (3.3.1-89)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	No	Boric Acid Corrosion Prevention	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and steel with stainless steel cladding piping, piping components, piping elements, tanks, and fuel storage racks exposed to treated borated water > 60°C (> 140°F) (3.3.1-90)	Cracking due to SCC	Water Chemistry	No	Water Chemistry Control – Primary and Secondary	Consistent with GALL Report
Stainless steel and steel with stainless steel cladding piping, piping components, and piping elements exposed to treated borated water (3.3.1-91)	Loss of material due to pitting and crevice corrosion	Water Chemistry	No	Water Chemistry Control – Primary and Secondary	Consistent with GALL Report
Galvanized steel piping, piping components, and piping elements exposed to air - indoor uncontrolled (3.3.1-92)	None	None	NA	Not applicable. No Aging Effect Mechanism or AMP	Not applicable. Galvanized steel surfaces are evaluated as steel for the auxiliary systems. (See SER Section 3.3.2.1.1)
Glass piping elements exposed to air, air - indoor uncontrolled (external), fuel oil, lubricating oil, raw water, treated water, and treated borated water (3.3.1-93)	None	None	NA	Not applicable. No Aging Effect Mechanism or AMP	Not applicable (See SER Section 3.3.2.1.1)
Stainless steel and nickel alloy piping, piping components, and piping elements exposed to air - indoor uncontrolled (external) (3.3.1-94)	None	None	NA	Not applicable. No Aging Effect Mechanism or AMP	Not applicable (See SER Section 3.3.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel and aluminum piping, piping components, and piping elements exposed to air - indoor controlled (external) (3.3.1-95)	None	None	NA	Not applicable. No Aging Effect Mechanism or AMP	Not applicable (See SER Section 3.3.2.1.1)
Steel and stainless steel piping, piping components, and piping elements in concrete (3.3.1-96)	None	None	NA	Not applicable. No Aging Effect Mechanism or AMP	Not applicable (See SER Section 3.3.2.1.1)
Steel, stainless steel, aluminum, and copper alloy piping, piping components, and piping elements exposed to gas (3.3.1-97)	None	None	NA	Not applicable. No Aging Effect Mechanism or AMP	Not applicable (See SER Section 3.3.2.1.1)
Steel, stainless steel, and copper alloy piping, piping components, and piping elements exposed to dried air (3.3.1-98)	None	None	NA	Not applicable. No Aging Effect Mechanism or AMP	Not applicable (See SER Section 3.3.2.1.1)
Stainless steel and copper alloy < 15% Zn piping, piping components, and piping elements exposed to air with borated water leakage (3.3.1-99)	None	None	NA	Not applicable. No Aging Effect Mechanism or AMP	Not applicable. There are no copper alloy components exposed to air with borated water leakage in the auxiliary systems. (See SER Section 3.3.2.1.1)

The staff's review of the auxiliary systems component groups followed any one of several approaches. In one approach, documented in SER Section 3.3.2.1, the staff reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. In the second approach, documented in SER Section 3.3.2.2, the staff reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. In the third approach, documented in SER Sections 3.3A.2.3 (for IP2) and 3.3B.2.3 (for IP3), the staff reviewed AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the auxiliary systems components is documented in SER Section 3.0.3.

3.3.2.1 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 Steel Tanks Program
- Bolting Integrity Program
- Boraflex Monitoring Program
- Boral Surveillance Program
- Boric Acid Corrosion Prevention Program
- Buried Piping and Tanks Inspection Program
- Diesel Fuel Monitoring Program
- External Surfaces Monitoring Program
- Fire Protection Program
- Fire Water System Program
- Flow-Accelerated Corrosion Program
- Heat Exchanger Monitoring Program
- Oil Analysis Program
- One-Time Inspection Program
- Periodic Surveillance and Preventive Maintenance Program
- Selective Leaching Program
- Service Water Integrity Program
- Water Chemistry Control - Auxiliary Systems Program
- Water Chemistry Control - Closed Cooling Water Program
- Water Chemistry Control - Primary and Secondary Program

LRA Tables 3.3.2-1-IP2 through 3.3.2-18-IP2, 3.3.2-1-IP3 through 3.3.2-18-IP3, 3.3.2-19-1-IP2 through 3.3.2-19-44-IP2, and 3.3.2-19-1-IP3 through 3.3.2-19-65-IP3 summarize the results of AMRs for the auxiliary system components and indicate AMRs claimed to be consistent with the GALL Report.

For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the report, where the report 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.

For each AMR line item, the applicant stated how the information in the tables aligns with the information in the GALL Report. Notes A through E indicate how the AMR is consistent with the GALL Report. The staff audited these AMRs.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report and validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report and verified that the identified exceptions to the GALL Report AMPs have been reviewed and accepted. The staff also determined whether the applicant's AMP was consistent with the

GALL Report AMP and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the 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 line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review and whether the identified exceptions to the GALL Report AMPs have been reviewed and accepted. The staff also determined whether the applicant’s AMP was consistent with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but credits a different AMP. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the credited AMP would manage the aging effect consistently with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

The staff audited and reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs.

The staff reviewed the LRA to confirm that the applicant: (a) provided a brief description of the system, components, materials, and environments; (b) stated that the applicable aging effects were reviewed and evaluated in the GALL Report; and (c) identified those aging effects for the auxiliary systems components that are subject to an AMR.

In response to RAI 2.3A.4.5-1, by letter dated January 4, 2008, the applicant revised the LRA to include several AMR line items associated with IP1 condensate storage tank and piping to the IP2 condensers which were not previously included in scope under 10 CFR 54.4(a)(3). The AMR line items added included carbon steel piping, tank and valve body with an internal environment of treated air, an external environment of outdoor air, an aging effect of loss of material, and Note A or Note A with plant-specific Note 314.

In response to RAI 2.1-1, Part (b), by letter dated February 13, 2008, the applicant revised the LRA to include several AMR line items associated with chlorination system which were not previously included within the scope of license renewal under 10 CFR 54.4(a)(2). The AMR line items added included carbon steel bolting, piping, and valve body with an internal environment of treated air, an external environment of indoor air, an aging effect of loss of material, and Note A.

In response to RAI 2.3A.2.2-1, by letter dated March 12, 2008, the applicant revised the LRA to include several AMR line items associated with the component cooling water and building vent sampling (IP3) systems which were not previously included within the scope of license renewal under 10 CFR 54.4(a)(2). The AMR line items added included stainless steel bolting, piping, tubing, filter housing and valve body with internal environments of treated water or indoor air, an external environment of indoor air, an aging effect of loss of material or "none," and Notes A or C. Also added were carbon steel bolting, flow element, heat exchanger housing, piping, strainer housing, thermowell, and valve body with an internal environment of treated water, an external environment of indoor air, an aging effect of loss or material, and Notes A, B, or C.

In response to RAI 2.2B-2, by letter dated March 12, 2008, the applicant revised the LRA to include several AMR line items associated with the hydrogen system which was not previously included within the scope of license renewal under 10 CFR 54.4(a)(2). The AMR line items added included carbon steel bolting, stainless steel bolting, stainless steel piping, stainless steel valve bodies, and copper alloy >15 percent zinc valve bodies with an internal environment of gas, an external environment of indoor air, an aging effect of loss of material (for carbon steel bolting only) or "none," and Notes A or C.

In response to RAI 2.3.0-2, by letter dated March 12, 2008, the applicant revised the LRA to add AMR line items associated with the reactor coolant pump motor upper and lower bearing heat exchangers that were not previously identified as subject to an AMR. The AMR line items added included carbon steel heat exchanger bonnet and tubes with an internal environment of treated water, external environments of indoor air or lube oil, an aging effect of loss of material, and Notes A or D.

By letter dated April 30, 2008, the applicant amended the LRA to reflect the installation of the IP2 SBO/Appendix R diesel generator. In the amendment, the applicant revised LRA Table 3.3.2-16-IP2 to reflect the changes to the AMRs as a result of the modification. The revised AMR line items included numerous components of various materials, environments, and aging effects with Notes A through E. The staff's evaluation of the AMR line item with Note E is documented in SER Section 3.2.2.1.3.

By letter dated June 11, 2008, the applicant submitted an annual update to the LRA, which included a clarification to components included within the scope of license renewal for 10 CFR 54.4(a)(2) as a result of the regional inspections. The applicant revised several LRA tables in the 3.3.2-19-XX series to add numerous components made of carbon steel, stainless steel, gray cast iron, elastomer, and glass exposed to internal environments of treated water, treated water >140°F, indoor air, and raw water, and external environment of indoor air. The revised AMR line items included numerous aging effects with Notes A through E. The staff's evaluation of the AMR line items with Note E is documented in SER Sections 3.2.2.1.3, 3.3.2.1.3, 3.3.2.1.9, 3.3.2.1.11, 3.3.2.2.5(1), 3.3.2.2.5(2), and 3.4.2.2.1.

By letter dated June 30, 2009, the applicant submitted an annual update to the LRA, identifying changes made to the CLB that materially affect the contents of the LRA. For the plant drains system, the applicant revised LRA Tables 3.3.2-18-IP2 and 3.3.2-18-IP3 to add gray cast iron valve bodies exposed internally to indoor air with an aging effect of "loss of material," and exposed externally to indoor air with an aging effect of "none," and Notes A and E, respectively. The staff's evaluation of the AMR line item with Note E is documented in SER Section 3.2.2.1.3. For the security generator system, the applicant replaced carbon steel flexible bellows with stainless steel flexible bellows, and listed the aging effect and AMP as "none." The applicant annotated this line item with Note C.

The staff reviewed the applicant's revisions, noted above, and found that the additional AMR results are consistent with the GALL Report for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

On the basis of its audit and review, the staff determines that, for AMRs not requiring further evaluation, as identified in LRA Table 3.3.1, the applicant's references to the GALL Report are acceptable and no further staff review is required.

3.3.2.1.1 AMR Results Identified as Not Applicable

LRA Table 3.3.1, Line Item 36 addresses the reduction of neutron-absorbing capacity due to boraflex degradation in boraflex spent fuel storage racks neutron-absorbing sheets exposed to treated water in BWRs. The LRA states that this line item is only applicable to Boiling Water Reactor designs, and, therefore, it is not applicable. Since IP2 and IP3 are both PWRs, the staff finds this to be consistent with the GALL Report, and, therefore, acceptable.

LRA Table 3.3.1, Line Item 37 addresses cracking due to SCC and intergranular SCC in stainless steel piping, piping components, and piping elements exposed to treated water >60°C (>140°F) in BWRs. The LRA states that this line item is only applicable to Boiling Water Reactor designs, and, therefore, it is not applicable. Since IP2 and IP3 are both PWRs, the staff finds this to be consistent with the GALL Report, and, therefore, acceptable.

LRA Table 3.3.1, Line Item 38 addresses cracking due to SCC in stainless steel piping, piping components, and piping elements exposed to treated water >60°C (>140°F) in BWRs. The LRA states that this line item is only applicable to Boiling Water Reactor designs, and, therefore, it is not applicable. Since IP2 and IP3 are both PWRs, the staff finds this to be consistent with the GALL Report, and, therefore, acceptable.

LRA Table 3.3.1, Line Item 39 addresses cracking due to SCC in stainless steel spent fuel storage racks exposed to treated water >60°C (>140°F) in BWRs. The LRA states that this line item is only applicable to Boiling Water Reactor designs, and, therefore, it is not applicable. Since IP2 and IP3 are both PWRs, the staff finds this to be consistent with the GALL Report, and, therefore, acceptable.

LRA Table 3.3.1, Line Item 41 addresses cracking due to cyclic loading, SCC in high-strength steel closure bolting exposed to air with steam or water leakage. The LRA states that high-strength steel bolts are not used in the Non-Class 1 auxiliary systems. During the audit the staff confirmed that the bolting used in Non-Class 1 components is not high strength steel, and that no high strength steel bolts were identified by the applicant during its aging management review of auxiliary systems. The staff finds this to be consistent with the GALL Report and, therefore, acceptable.

LRA Table 3.3.1, Line Item 61 addresses increased hardness, shrinkage and loss of strength due to weathering in elastomeric seals exposed to air – outdoor or air – indoor uncontrolled. This line item was not used in the auxiliary systems tables. Fire barrier seals are evaluated as structural components in SER Section 3.5. Cracking and the change in material properties of elastomer seals are managed by the Fire Protection Program. SER Section 3.5.2.3.4 documents the staff's evaluation of this item.

LRA Table 3.3.1, Line Item 63 addresses loss of material due to wear in steel fire rated doors exposed to air – outdoor or air - indoor uncontrolled. The GALL Report recommends that loss of material due to wear of steel fire doors be managed by the Fire Protection Program. The LRA states that this line item was not used in the auxiliary systems tables. Steel fire doors are evaluated as structural components in Section 3.5, Structures and Component Supports. SER Section 3.5.2.1 documents the staff's evaluation of this item.

LRA Table 3.3.1, Line Item 65 addresses concrete cracking and spalling of reinforced concrete fire barriers (walls, ceilings, and floors) exposed to uncontrolled indoor air. The GALL Report recommends that concrete cracking and spalling be managed by the Fire Protection and Structures Monitoring Program. The LRA states that this line item was not used in the auxiliary systems tables. Reinforced concrete fire barriers are evaluated as structural components in Section 3.5, Structures and Component Supports. SER Sections 3.5.2.3 and 3.5.2.4 document the staff's evaluation of this item.

LRA Table 3.3.1, Line Item 66 addresses concrete cracking and spalling of reinforced concrete fire barriers (walls, ceilings, and floors) exposed to outdoor air. The GALL Report recommends that concrete cracking and spalling be managed by the Fire Protection and Structures Monitoring Program. The LRA states that this line item was not used in the auxiliary systems tables. Reinforced concrete fire barriers are evaluated as structural components in Section 3.5, Structures and Component Supports. SER Section 3.5.2.3 documents the staff's evaluation of this item.

LRA Table 3.3.1, Line Item 67 addresses loss of material due to corrosion of embedded steel of reinforced concrete fire barriers exposed to uncontrolled outdoor or indoor air. The GALL Report recommends that concrete cracking and spalling be managed by the Fire Protection and Structures Monitoring Program. The LRA states that this line item was not used in the auxiliary systems tables. Reinforced concrete fire barriers are evaluated as structural components in Section 3.5, Structures and Component Supports. SER Section 3.5.2.3 documents the staff's evaluation of this item.

LRA Table 3.3.1, Line Item 73 addresses loss of material due to general corrosion in steel crane structural girders in load handling system exposed to air- indoor uncontrolled (external). The GALL Report recommends that the loss of material due to wear be managed by the inspection of overhead heavy load and light load (related to refueling) handling systems. The LRA states that this line item was not used in the auxiliary systems tables. Steel crane structural girders are evaluated as structural components in Section 3.5, Structures and Component Supports. Loss of material for steel crane structural components is managed by the Periodic Surveillance and Preventive Maintenance and Structures Monitoring Programs using periodic visual or other NDE techniques. SER Section 3.5.2.3 documents the staff's evaluation of this item.

LRA Table 3.3.1, Line Item 74 addresses loss of material due to wear in steel crane rails exposed to uncontrolled indoor air. The GALL Report recommends that the loss of material due to wear be managed by the inspection of overhead heavy load and light load (related to refueling) handling systems. The LRA states that this line item was not used in the auxiliary systems tables. Steel crane rails are evaluated as structural components in Section 3.5, Structures and Component Supports. SER Section 3.5.2.3 documents the staff's evaluation of this item.

LRA Table 3.3.1, Line Item 86 addresses loss of material due to general, pitting, and crevice corrosion in structural steel (new fuel storage rack assembly) exposed to air – indoor uncontrolled (external). The GALL Report recommends that these aging mechanisms be managed by the Structures Monitoring Program. The LRA states that this line item was not used in the auxiliary systems tables. Structural steel of the new fuel storage rack is evaluated as a structural component in Section 3.5, Structures and Component Supports, of the LRA. The staff finds this to be consistent with the GALL Report and, therefore, is acceptable.

LRA Table 3.3.1, Line Item 92 addresses the lack of an aging effect in galvanized steel piping, piping components, and piping elements exposed to uncontrolled indoor air. Since there is no aging effect applicable to these components when exposed to indoor air, the GALL Report does not recommend any AMP. Therefore this line item is identified in the LRA as not applicable. Although this specific line item is not applicable, the LRA states that galvanized steel surfaces of the auxiliary systems are evaluated as steel. The staff finds this is consistent with the GALL Report and, therefore, is acceptable.

LRA Table 3.3.1, Line Item 93 addresses the lack of an aging effect in glass piping elements exposed to air, air – indoor uncontrolled (external), fuel oil, lubricating oil, raw water, treated water, and treated borated water. Since there is no aging effect applicable to these components when exposed to uncontrolled indoor air, fuel oil, lubricating oil, raw water, treated water, or treated borated water, the GALL Report does not recommend any AMP. Therefore, this line item is identified in the LRA as not applicable. The staff finds this is consistent with the GALL Report and, therefore, is acceptable.

LRA Table 3.3.1, Line Item 94 addresses the lack of an aging effect in stainless steel and nickel alloy piping, piping components, and piping elements exposed to uncontrolled indoor air (external). Since there is no aging effect applicable to these components when exposed to indoor air, the GALL Report does not recommend any AMP. In addition, the LRA states that there are no nickel alloy components exposed to uncontrolled indoor air in the auxiliary systems. The staff finds that the classification of this line item in the LRA as not applicable is consistent with the GALL Report and, therefore is acceptable.

LRA Table 3.3.1, Line Item 95 addresses the lack of an aging effect in steel and aluminum piping, piping components, and piping elements exposed to indoor controlled air (external). Since there is no aging effect applicable to these components when exposed to indoor air, the GALL Report does not recommend any AMP. The LRA also states that since all indoor air environments are conservatively considered to be uncontrolled. There are no steel or aluminum components in the auxiliary systems that are exposed to indoor controlled air. The staff finds that the classification of this line item in the LRA as not applicable is consistent with the GALL Report and, therefore is acceptable.

LRA Table 3.3.1, Line Item 96 addresses the lack of an aging effect in steel and stainless steel piping, piping components, and piping elements in concrete. Since there is no aging effect applicable to these components when exposed to concrete, the GALL Report does not recommend any AMP. The staff finds that the classification of this line item in the LRA as not applicable is consistent with the GALL Report and, therefore is acceptable.

LRA Table 3.3.1, Line Item 97 addresses the lack of an aging effect in steel, stainless steel, aluminum, and copper alloy piping, piping components, and piping elements exposed to gas. Since there is no aging effect applicable to these components when exposed to gas, the GALL Report does not recommend any AMP. The staff finds that the classification of this line item in the LRA as not applicable is consistent with the GALL Report and, therefore is acceptable.

LRA Table 3.3.1, Line Item 98 addresses the lack of an aging effect in steel, stainless steel, and copper alloy piping, piping components, and piping elements exposed to dried air. Since there is no aging effect applicable to these components when exposed to dried air, the GALL Report does not recommend any AMP. The staff finds that the classification of this line item in the LRA as not applicable is consistent with the GALL Report and, therefore is acceptable.

LRA Table 3.3.1, Line Item 99 addresses the lack of an aging effect in stainless steel and copper alloy <15 percent zinc piping, piping components, and piping elements exposed to air with borated water leakage . Since there is no aging effect applicable to stainless steel components when exposed to air with borated water leakage, the GALL Report does not recommend any AMP. In addition, the LRA states that there are no copper alloy components exposed to air with borated water leakage in the auxiliary systems. The staff finds that the classification of this line item in the LRA as not applicable is consistent with the GALL Report and, therefore is acceptable.

3.3.2.1.2 Loss of Material Due to General Corrosion

LRA Table 3.3.1, Line Item 42 addresses loss of material due to general corrosion in steel closure bolting exposed to air with steam or water leakage. The GALL Report recommends the Bolting Integrity AMP to manage loss of material in these components. The LRA states that this line item was not used since loss of material due to general corrosion in steel closure bolting exposed to air with steam or water leakage is addressed by other line items, including 3.3.1-43, 3.3.1-44 and 3.3.1-55. During the audit the staff questioned if bolting in the auxiliary systems at IP is exposed to air with steam or water leakage (Audit Item 219). In its response, dated December 18, 2007, the applicant stated that IP2 and IP3 do not have bolting exposed to air with leakage as a normal environment for bolted connections for auxiliary systems. The applicant further stated that if a leak occurs, it is corrected under the site corrective action or corrective maintenance programs. Therefore, as identified in Table 3.3-1, Item 3.3.1-42 was not used. The Bolting Integrity Program is applied to steel closure bolting as indicated by other items including 3.3.1-43, 3.3.1-44 and 3.3.1-55. Since IP does not have bolting exposed to air with leakage as a normal environment for bolted connections for auxiliary systems, and the applicant appropriately uses the Bolting Integrity AMP for steel closure bolting consistent with the GALL Report, the staff finds this acceptable.

3.3.2.1.3 Loss of Material Due to General, Pitting, and Crevice Corrosion

LRA Table 3.3.1, Line Item 53 addresses loss of material due to general and pitting corrosion for steel compressed air system piping, piping components, and piping elements exposed to condensation (internal). Rather than using the Compressed Air Monitoring Program, the applicant uses the Periodic Surveillance and Maintenance Program to manage this aging effect. The staff finds that this is acceptable because the program will use periodic visual inspections or other NDE techniques to manage this aging.

By letter dated June 11, 2008, the applicant amended its LRA to state that carbon valve bodies exposed internally to condensation have an aging effect of loss of material in LRA Table 3.3.2-19-48-IP3. For these AMR line items the applicant proposed the Periodic Surveillance and Maintenance Program. These AMR line items referenced LRA Table 3.3.1, Line Item 53.

By letter dated June 12, 2009, the applicant amended its LRA to state that carbon steel filter housing, piping, tubing, trap, strainer housing, tank and valve bodies exposed internally to condensation have an aging effect of loss of material in the IP1 Station Air System. For these AMR line items the applicant proposed the Periodic Surveillance and Maintenance Program. These AMR line items referenced LRA Table 3.3.1, line item 53.

LRA Table 3.3.1, Line Item 54 addresses loss of material due to pitting and crevice corrosion for stainless steel compressed air system piping, piping components, and piping elements exposed to condensation (internal). Rather than using the Compressed Air Monitoring Program, the applicant uses the One-Time Inspection Program to manage this aging effect. The staff finds this acceptable because visual or other NDE techniques will be used to inspect a representative sample of the internal surfaces to confirm the absence of significant loss of material.

By letter dated June 12, 2009, the applicant amended its LRA to state that stainless steel tubing, piping, strainer and valve bodies exposed internally or externally to condensation have an aging effect of loss of material in the IP1 Station Air System. For these AMR line items the applicant proposed the One-Time Inspection Program. These AMR line items referenced LRA Table 3.3.1, Line Item 54.

3.3.2.1.4 Loss of Preload Due to Thermal Effects, Gasket Creep and Self-loosening

LRA Table 3.3.1, Line Item 45 addresses loss of preload due to thermal effects, gasket creep and self-loosening of steel closure bolting exposed to uncontrolled indoor air. The GALL Report recommends the Bolting Integrity Aging Management Program to manage loss of preload in these components. The LRA states that loss of preload due to stress relaxation (creep) is not an applicable aging effect for auxiliary systems because it is only a concern for very high temperature applications (>700º F per ASME Code, Section II, Part D, Table 4) and bolting in auxiliary systems operates at <700º F. The LRA further states that other issues such as gasket creep and loosening that may result in pressure boundary joint leakage are improper design or maintenance issues and that improper bolting application (design) and maintenance issues are current plant operational concerns and are not related to aging effects or mechanisms that require management during the period of extended operation. In the LRA, the applicant further states that actions have been taken to address NUREG-1339, Resolution to Generic Safety Issue 29, “Bolting Degradation or Failure in Nuclear Power Plants.” These actions include implementation of good bolting practices in accordance with EPRI NP-5067, Good Bolting Practices.

During the audit, the staff questioned the applicant about loss of preload (Audit Item 201). By letter dated December 18, 2007, the applicant responded to this question by taking the position that loss-of preload is event driven and not an aging effect. The staff questioned the applicant about how a loss of preload is currently managed and requested the applicant to describe (a) the operating experience with loss of bolt pre-load and (b) how the absence or loss of bolt pre-load is confirmed (Audit Item 220). In its response, dated December 18, 2007, the applicant stated that loss of preload is managed by the Bolting Integrity Program which includes preventive measures to preclude or minimize loss of preload and cracking. The applicant further stated that during the period of extended operation, the Bolting Integrity Program will be consistent with the program described in the Gall Report, Section XI.M18. As stated in this section of the GALL Report under detection of aging effects, the absence of loss of bolt preload is confirmed by visual examination during system leakage testing of all pressure-retaining Class 1, 2 and 3 components, according to Tables IWB 2500-1, IWC 2500-1, and IWD 2500-1, respectively. In addition, the applicant states that degradation of the closure bolting due to crack initiation, loss of prestress, or loss of material due to corrosion of the closure bolting would result in leakage. The extent and schedule of inspections, in accordance with Tables IWB 2500-1, IWC 2500-1, and IWD 2500-1, combined with periodic system walkdowns, assure detection of leakage before the leakage becomes excessive. For other pressure retaining bolting, periodic system walkdowns assure detection of leakage before the leakage becomes excessive. With regard to operating experience, the applicant stated it has been consistent with that experienced within the industry.

In a letter dated December 18, 2007, the applicant clarified Commitment 2 to specifically state that the Bolting Integrity Program manages loss of preload and loss of material for all external loading. The applicant also stated that the clarification will be incorporated into the LRA (response to Audit Questions 241 and 270). In attachment 1 to this letter, the applicant amended the LRA to incorporate this change.

The staff finds the applicant’s response acceptable, because the Bolting Integrity Program includes preventive measures that preclude or minimize loss of preload. This is consistent with the GALL Report. On this basis, the staff finds the AMR results for this line item acceptable.

3.3.2.1.5 Hardening and Loss of Strength Due to Elastomer Degradation; Loss of Material Due to Erosion

LRA Table 3.3.1, Line Item 75 addresses hardening and loss of strength due to elastomer degradation; loss of material due to erosion in elastomer seals and components exposed to raw water. The GALL Report recommends that these aging effects be managed by the Open-Cycle Cooling Water System. The LRA states that the components to which this line item applies are included in scope under criterion 10 CFR 54.4(a)(2) and are listed in series 3.3.2-19-XX tables in systems other than service water. The Periodic Surveillance and Preventive Maintenance Program uses periodic visual inspections of internal and external surfaces of components to manage cracking and change of material properties in elastomeric components exposed to raw water. The staff finds the Periodic Surveillance and Preventive Maintenance Program appropriately manages the applicable aging effects for elastomer components within scope under criterion 10 CFR 54.4(a)(2), and is, therefore, acceptable.

The staff evaluated the applicant’s claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant’s consideration of recent operating experience and proposals for managing aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with its AMRs. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.6 Loss of Material Due to Pitting and Crevice Corrosion

LRA Table 3.3.1, Line Item 62 addresses loss of material due to pitting and crevice corrosion for aluminum piping, piping components, and piping elements exposed to raw water. The GALL Report recommends using the Fire Protection Program to manage this aging effect. The applicant proposes using the One-Time Inspection Program and the Service Water Integrity Program to manage the aging. The staff finds this to be acceptable because the One-Time Inspection Program will use visual and other NDE techniques to determine if degradation has occurred and the Service Water Integrity Program uses periodic inspections to ensure that degradation is not occurring.

LRA Table 3.3.1, Line Item 71 addresses loss of material due to general, pitting, crevice, and (for drip pans and drain lines) microbiologically-influenced corrosion in steel piping, piping components, and piping elements exposed to moist air or condensation (Internal). The GALL Report states that these aging effects should be managed by inspection of internal surfaces in miscellaneous piping and ducting components. The LRA states that the Periodic Surveillance and Preventive Maintenance Program uses periodic visual inspections to manage loss of material for internal surfaces of steel ducting and components exposed to condensation. The LRA further states that the External Surfaces Monitoring Program manages loss of material for external carbon steel components of the service water system exposed to condensation, by visual inspection of external surfaces. For systems where internal carbon steel surfaces are exposed to the same environment as external surfaces, the LRA states that external surface conditions will be representative of internal surfaces. Thus, loss of material on internal carbon steel surfaces of the service water system exposed to condensation is also managed by the External Surfaces Monitoring Program. During the audit, the applicant was requested to identify and describe the applications of the External Surfaces Monitoring Program to manage loss of material for internal surfaces exposed to condensation and to justify its conclusion that the environment is the same (Audit Item 224). In its response, dated December 18, 2007, the applicant stated that the internal surfaces and external surfaces are exposed to the same environment and are subject to the same aging effects. Therefore, the condition of the external surfaces will be representative of the condition of the internal surfaces. The applicant further stated that the identification of a significant loss of material on the external surfaces will result in appropriate corrective actions to internal surfaces as well as external. In this manner, the External Surfaces Monitoring Program will manage loss of material on internal carbon steel surfaces exposed to indoor air. The staff finds this to be consistent with the GALL Report and, therefore, acceptable.

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

LRA Table 3.3.1, Line Item 72, addresses loss of material due to general, pitting, crevice, and (for drip pans and drain lines) microbiologically influenced corrosion of steel HVAC ducting and components internal surfaces exposed to condensation. The GALL Report recommends that the loss of material and MIC of the internal surfaces of steel HVAC ducting be managed by inspection of internal surfaces. The LRA states that loss of material on internal carbon steel surfaces of the service water system exposed to condensation is managed by the External Surfaces Monitoring Program. In response to Audit Question 224, dated December 18, 2007, the applicant stated that the internal surfaces are exposed to the same environment and subject to the same aging effects as the external surfaces. Based on its review of the applicant’s response, the staff agrees that the external surfaces will be representative of the condition of the internal surfaces.

3.3.2.1.8 Hardening and Loss of Strength Due To Elastomer Degradation; Loss Of Material Due To Erosion

By letter dated June 12, 2009, the applicant amended its LRA to state that elastomer expansion joints in the Circulating Water System and the Wash Water System exposed to internally to raw water have the aging effects of cracking and change in material properties.

LRA Table 3.3.1, Line Item 75 addresses hardening and loss of strength due to elastomer degradation; loss of material due to erosion in elastomer seals and components exposed to raw water. The GALL Report recommends that these aging effects be managed by the Open-Cycle Cooling Water System. The Periodic Surveillance and Preventive Maintenance Program uses periodic visual inspections of internal and external surfaces of components to manage cracking and change of material properties in elastomeric components exposed to raw water. The staff finds the Periodic Surveillance and Preventive Maintenance Program appropriately manages the applicable aging effects for elastomer components, and is therefore acceptable.

The staff evaluated the applicant's claim of consistency with the GALL Report. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.9 Loss of Material due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion, Fouling, and Lining/Coating Degradation

LRA Table 3.3.1, Line Item 76 addresses loss of material due to general, pitting, crevice, and microbiologically influenced corrosion, fouling, and lining/coating degradation in steel piping, piping components, and piping elements (without lining/coating or with degraded lining/coating) exposed to raw water. The GALL Report recommends that these aging effects be managed by the Open-Cycle Cooling Water System.

By letter dated June 11, 2008, the applicant amended LRA Table 3.3.2-19-31-IP2 to state that carbon steel pump casings exposed internally to raw water with the aging effect of loss of material will be managed by Periodic Surveillance and Preventive Maintenance Program.

By letter dated June 12, 2009, the applicant amended its LRA to state that carbon steel nozzles, valve bodies and piping in the Wash Water System exposed to internally to raw water have the aging effect of loss of material. Furthermore, for the river water service system the applicant amended its LRA to state that carbon steel piping and valve bodies and gray cast iron pump casings exposed internally to raw water have the aging effect of loss of material.

The applicant proposes to manage the effects of aging using the Periodic Surveillance and Preventive Maintenance Program. The staff's review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.3.7. The Periodic Surveillance and Preventive Maintenance Program enhancements add new activities to the plant's preventive maintenance and surveillance programs, which generally implement preventive maintenance and surveillance testing activities through repetitive tasks or routine monitoring of plant operations. On the basis of its review, the staff finds that because these components will be inspected periodically for loss of material, the aging effect for these component/environment combinations will be effectively managed by this aging management program.

The staff evaluated the applicant's claim of consistency with the GALL Report. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.10 Loss of Material Due to Pitting and Crevice Corrosion, and Fouling

LRA Table 3.3.1, Line Item 79, addresses loss of material due to pitting and crevice corrosion, and fouling of stainless steel piping, piping components, and piping elements exposed to raw water. The GALL Report recommends that this aging effect for these components be managed by the Open-Cycle Cooling Water System AMP. The LRA states that loss of material for some stainless steel piping, piping components, and piping elements will be managed by the One-Time Inspection Program. The staff's evaluation of the One-Time Inspection Program is documented in SER Section 3.0.3.1.9. The One-Time Inspection Program uses visual or other NDE techniques to confirm the absence of significant loss of material. The staff finds that use of the One-Time Inspection Program to detect loss of material in stainless steel piping, piping components and piping elements exposed to raw water is acceptable.

By letter dated June 12, 2009, the applicant amended its LRA to state that stainless steel flex hose, pump casing, tubing and valve bodies in the wash water system exposed to internally or externally to raw water have the aging effects of loss of material. Furthermore, for the river water service system the applicant amended its LRA to state that stainless steel tubing and valve bodies exposed internally to raw water have the aging effect of loss of material.

LRA Table 3.3.1, Line Item 79 addresses loss of material due to pitting and crevice corrosion, and fouling in Stainless steel piping, piping components, and piping elements exposed to raw water. The GALL Report recommends that these aging effects be managed by the Open-Cycle Cooling Water System.

The applicant proposes to manage the effects of aging using the Periodic Surveillance and Preventive Maintenance Program. The staff's review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.3.7. The Periodic Surveillance and Preventive Maintenance Program enhancements add new activities to the plant's preventive maintenance and surveillance programs, which generally implement preventive maintenance and surveillance testing activities through repetitive tasks or routine monitoring of plant operations. On the basis of its review, the staff finds that because these components will be inspected periodically for loss of material, the aging effect for these component/environment combinations will be effectively managed by this aging management program.

The staff evaluated the applicant's claim of consistency with the GALL Report. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.11 Loss of Material due to Pitting and Crevice Corrosion

By letter dated June 11, 2008, the applicant amended its LRA to state that for stainless steel heat exchanger housings exposed internally to treated borated water with an aging effect of loss of material will be managed by the Water Chemistry Control – Primary and Secondary Program in LRA Table 3.3.2-19-5-IP2. The staff noted that the applicant referenced LRA Table 3.3.1, Line Item 3.3.1-91.

LRA Table 3.3.1, Line Item 91 addresses loss of material due to pitting and crevice corrosion for stainless steel and steel with stainless steel cladding piping, piping components and piping elements exposed to treated borated water. The staff noted that the GALL Report recommends a program that corresponds to GALL AMP XI.M2, "Water Chemistry," for aging management. The staff's evaluation of the Water Chemistry Control – Primary and Secondary Program is documented in SER Section 3.0.3.2.17. The staff determined that the applicant's Water Chemistry Control – Primary and Secondary Program is consistent with GALL AMP XI.M2. The staff finds the applicant's use of the Water Chemistry Control – Primary and Secondary Program to be consistent with the recommendations of the GALL Report.

Based on its review of the program identified above, the staff determines that the applicant's proposed program is acceptable for managing the aging effect in the applicable components. The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2 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 system components and provides information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- reduction of heat transfer due to fouling
- cracking due to SCC
- cracking due to SCC and cyclic loading
- hardening and loss of strength due to elastomer degradation
- reduction of neutron-absorbing capacity and loss of material due to general corrosion
- loss of material due to general, pitting, and crevice corrosion
- loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion
- loss of material due to general, pitting, crevice, microbiologically-influenced corrosion and fouling

- loss of material due to pitting and crevice corrosion
- loss of material due to pitting, crevice, and galvanic corrosion
- loss of material due to pitting, crevice, and microbiologically-influenced corrosion
- loss of material due to wear
- loss of material due to cladding breach
- QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the report and for which the report recommends further evaluation, the staff audited and reviewed the applicant's evaluation to determine 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

Fatigue is an age-related degradation mechanism caused by cyclic stressing of a component by either mechanical or thermal stresses. SRP-LR Section 3.3.2.2.1 states that fatigue is a TLAA as defined in 10 CFR 54.3 and that TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). This TLAA is addressed separately in Section 4.3, "Metal Fatigue Analysis" or Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses" of the SRP-LR.

LRA Section 3.3.2.2.1 states that TLAAs are evaluated in accordance with 10 CFR 54.21(c) and that the evaluation of this TLAA is addressed in Section 4.3.2. This is consistent with SRP-LR Section 3.3.2.2.1 and is, therefore, acceptable.

3.3.2.2.2 Reduction of Heat Transfer Due to Fouling

The staff reviewed LRA Section 3.3.2.2.2 against the criteria in SRP-LR Section 3.3.2.2.2.

LRA Section 3.3.2.2.2 addresses reduction of heat transfer due to fouling in stainless steel heat exchanger tubes exposed to treated water, stating that this aging effect is not applicable because at IP, there are no stainless steel heat exchanger tubes exposed to treated water in the auxiliary systems with an intended function of heat transfer.

SRP-LR Section 3.3.2.2.2 states that reduction of heat transfer due to fouling may occur in stainless steel heat exchanger tubes exposed to treated water.

The staff confirmed that there are no stainless steel heat exchanger tubes exposed to treated water in the auxiliary systems with an intended function of heat transfer.

Based on the above, the staff concludes that SRP-LR Section 3.3.2.2.2 criteria do not apply.

3.3.2.2.3 Cracking Due to Stress Corrosion Cracking

The staff reviewed LRA Section 3.3.2.2.3 against the criteria in SRP-LR Section 3.3.2.2.3.

(1) LRA Section 3.3.2.2.3 addresses cracking due to SCC in the stainless steel components of a BWR standby liquid control (SLC) system, stating that this aging effect is not applicable to IP, which are PWRs.

SRP-LR Section 3.3.2.2.3 states that cracking due to SCC could occur in the stainless steel piping, piping components, and piping elements of the BWR standby liquid control system that are exposed to sodium pentaborate solution greater than 60°C (140°F).

IP2 and IP3 are PWRs and do not have SLC systems. Based on the above, the staff concludes that this item is not applicable to IP.

(2) LRA Section 3.3.2.2.3 addresses cracking due to SCC in stainless steel and stainless steel clad heat exchanger components exposed to treated water greater than 140°F, stating that this aging effect is not applicable because for IP, the only stainless steel heat exchanger components in the auxiliary systems exposed to treated water greater than 140°F are in the steam generator secondary side sample coolers.

SRP-LR Section 3.3.2.2.3 states that cracking due to SCC may occur in stainless steel and stainless clad steel heat exchanger components exposed to treated water greater than 60°C (140°F).

During the audit the staff requested the applicant to describe how cracking due to SCC in the secondary side sample coolers was addressed in the LRA (Audit Item 214). In its response, dated December 18, 2007, the applicant states that the steam generator secondary side sample coolers are included in scope for 54.4(a)(2) for potential spatial interaction. Although the tube side of the heat exchanger can experience temperatures above 140°F, it has no intended function because the potential for spatial interaction is prevented by the shell. In addition, the shell side of the coolers does not experience temperatures above 140°F.

The staff agrees with the applicant that the tube side of the heat exchanger is not with the scope of license renewal because there is no spatial interaction as a result of the presence of the shell, and the shell side of the coolers is not within scope of license renewal because they do not reach a high enough temperature for SCC to occur.

(3) LRA Section 3.3.2.2.3 addresses cracking due to SCC in stainless steel diesel engine exhaust piping exposed to diesel exhaust, stating that this aging effect is not applicable because at IP, the stainless steel exhaust components are not subject to significant moisture accumulation that would allow cracking to occur.

SRP-LR Section 3.3.2.2.3 states that cracking due to SCC may occur in stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust.

During the audit, the staff confirmed that the stainless steel exhaust components are not subject to significant moisture accumulation that would allow cracking to occur. In addition, the staff requested the applicant to define the intended function of the diesel exhaust piping for license renewal and to state if the piping was subject to aging management under any credited AMP (Audit Item 215). In its response, dated December 18, 2007, the applicant stated that stainless steel piping exposed to diesel exhaust has a pressure boundary intended function, and that exhaust system components are inspected for loss of material under the Periodic Surveillance and Preventive Maintenance Program at least once every six years during the period of extended operation. The GALL Report identifies aging effects for this material/environment combination of stress corrosion cracking and loss of material. As discussed, insignificant moisture accumulation is present to allow cracking to occur. The aging effect of concern is a loss of material which will be inspected for periodically during the extended period of operation. The staff finds that this approach is consistent with the GALL Report and is therefore acceptable.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.3 criteria. For those line items that apply to LRA Section 3.3.2.2.3, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.4 Cracking Due to Stress Corrosion Cracking and Cyclic Loading

The staff reviewed LRA Section 3.3.2.2.4 against the criteria in SRP-LR Section 3.3.2.2.4.

(1) LRA Section 3.3.2.2.4 addresses cracking due to SCC and cyclic loading in stainless steel PWR nonregenerative heat exchanger components exposed to treated borated water greater than 140°F in the chemical and volume control system, stating that the Water Chemistry Control - Primary and Secondary Program manages this aging effect. The program is augmented by the One-Time Inspection Program to verify the absence of cracking by visual and volumetric NDE techniques. Absence of tube and tubesheet cracking is also verified by monitoring of reactor coolant system leakage and radiation levels in the component cooling water system. Temperature monitoring, a much less sensitive technique, is not used.

SRP-LR Section 3.3.2.2.4 states that cracking due to SCC and cyclic loading may occur in stainless steel PWR nonregenerative heat exchanger components exposed to treated borated water greater than 60°C (140°F) in the chemical and volume control system. The existing AMP monitors and controls primary water chemistry in PWRs to manage the aging effects of cracking due to SCC. However, control of water chemistry does not preclude cracking due to SCC and cyclic loading; therefore, the effectiveness of water chemistry control programs should be verified to ensure that cracking does not occur. The GALL Report recommends that a plant-specific AMP be evaluated to verify the absence of cracking due to SCC and cyclic loading to ensure that these aging effects are adequately managed. An acceptable verification program is to include temperature and radioactivity monitoring of the shell side water and eddy current testing of tubes.

During the audit, the staff asked the applicant to identify the specific component inspections currently included in the existing program that are credited for license renewal (Audit Item 52). In its response, dated December 18, 2007, the applicant stated that the existing site eddy current heat exchanger inspection program includes safety-related and nonsafety-related heat exchangers. The GALL Report recommends that this testing be augmented by temperature and radioactivity monitoring of the shell side water. The staff verified that the applicant's program confirms the absence of cracking by monitoring leakage of the RCS and the radiation levels in the component cooling water system. The applicant's method of verifying the absence of cracking due to SCC and cyclic loading is equivalent to the approach recommended in GALL Report, and is, therefore, acceptable.

(2) LRA Section 3.3.2.2.4 addresses cracking due to SCC and cyclic loading in stainless steel PWR regenerative heat exchanger components exposed to treated borated water greater than 140°F, stating that the Water Chemistry Control - Primary and Secondary Program manages this aging effect. The regenerative heat exchanger is of all-welded construction and inspections are not possible. The Water Chemistry Control - Primary and Secondary Program is augmented by the One-Time Inspection Program to verify the absence of cracking by visual and volumetric NDE techniques with components in similar environments.

SRP-LR Section 3.3.2.2.4 states that cracking due to SCC and cyclic loading may occur in stainless steel PWR regenerative heat exchanger components exposed to treated borated water greater than 60°C (140°F). The existing AMP monitors and controls primary water chemistry in PWRs to manage the aging effects of cracking due to SCC. However, control of water chemistry does not preclude cracking due to SCC and cyclic loading; therefore, the effectiveness of water chemistry control programs should be verified to ensure that cracking does not occur. The GALL Report recommends that a plant-specific AMP be evaluated to verify the absence of cracking due to SCC and cyclic loading to ensure that these aging effects are adequately managed.

The staff confirmed that the Water Chemistry Control – Primary and Secondary Program manages cracking of stainless steel regenerative heat exchanger components exposed to treated borated water and that the all-welded construction of the heat exchanger negates the possibility of inspection. The absence of cracking will be determined by the One-Time Inspection Program which includes the use of visual and volumetric NDE techniques of components in similar environments. The staff finds that the use of the One-Time inspection program is consistent with the GALL Report recommendation to verify the absence of cracking due to SCC and cyclic loading, and is therefore acceptable.

(3) LRA Section 3.3.2.2.4 addresses cracking due to SCC and cyclic loading in the stainless steel pump casing of PWR high-pressure pumps in the chemical and volume control system (CVCS), stating that the Water Chemistry Control - Primary and Secondary program manages loss of material for the pump casing. CVCS stainless steel charging pump casings are exposed to treated borated water below the 140°F threshold for SCC; consequently, they do not specifically credit the Water Chemistry Control – Primary and Secondary Program to manage cracking due to SCC. The Periodic Surveillance and Preventive Maintenance Program manages charging pump cracking due to cyclic loading by visual inspections of external casing surfaces for signs of cracking or leakage during the regularly scheduled quarterly pump surveillances.

SRP-LR Section 3.3.2.2.4 states that cracking due to SCC and cyclic loading may occur in the stainless steel pump casing for the PWR high-pressure pumps in the chemical and volume control system. The existing AMP monitors and controls primary water chemistry in PWRs to manage the aging effects of cracking due to SCC. However, control of water chemistry does not preclude cracking due to SCC and cyclic loading; therefore, the effectiveness of water chemistry control programs should be verified to ensure that cracking does not occur. The GALL Report recommends that a plant-specific AMP be evaluated to verify the absence of cracking due to SCC and cyclic loading to ensure that these aging effects are adequately managed.

The staff confirmed that loss of material for the CVCS pump casing is adequately managed by the Water Chemistry Control – Primary and Secondary program. The staff also verified that stainless steel CVCS charging pump casings are exposed to treated borated water that is below the 140°F threshold for SCC and that the absence of cracking due to SCC and cyclic loading is verified by the Periodic Surveillance and Preventive Maintenance Program, which includes visual inspections of external casing surfaces for signs of cracking or leakage during the regularly scheduled quarterly pump surveillances. The staff finds that the applicant's approach is consistent with the GALL Report, and is, therefore, acceptable.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.4 criteria. For those line items that apply to LRA Section 3.3.2.2.4, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.5 Hardening and Loss of Strength Due to Elastomer Degradation

The staff reviewed LRA Section 3.3.2.2.5 against the criteria in SRP-LR Section 3.3.2.2.5.

(1) LRA Section 3.3.2.2.5 addresses cracking and change in material properties due to elastomer degradation in elastomer flexible connections of auxiliary and other systems exposed to air - indoor, stating that the Periodic Surveillance and Preventive Maintenance Program manages these aging effects by periodic visual inspections and physical manipulation of the flexible connections for whether the components have experienced aging that would affect performance of intended functions.

SRP-LR Section 3.3.2.2.5 states that hardening and loss of strength due to elastomer degradation may occur in elastomer seals and components of heating and ventilation systems exposed to air - indoor uncontrolled (internal/external). The GALL Report recommends further evaluation of a plant-specific AMP to ensure that these aging effects are adequately managed.

By letter dated June 11, 2008, the applicant amended LRA Table 3.3.2-19-9-IP3 to state that elastomer expansion joints exposed externally to air-indoor with an aging effect of cracking and change in material properties will be managed by the Periodic Surveillance and Maintenance Program. The applicant referenced LRA Table 3.3.1, Line Item 3.3.1-11.

The staff confirmed that cracking and change in material properties due to elastomer degradation in elastomer flexible connections of auxiliary and other systems exposed to air – indoor, are managed by the Periodic Surveillance and Preventive Maintenance Program. The staff also verified that the AMP includes periodic visual inspections to detect the effects of aging before they could affect a component's ability to accomplish its intended function.

(2) LRA Section 3.3.2.2.5 addresses cracking and change in material properties due to elastomer degradation in auxiliary system components, stating that the Periodic Surveillance and Preventive Maintenance Program manages them by periodic visual inspections of a representative sample of interior and exterior elastomer surfaces for whether the components have experienced aging that would affect performance of intended functions.

SRP-LR Section 3.3.2.2.5 states that hardening and loss of strength due to elastomer degradation may occur in elastomer linings of the filters, valves, and ion exchangers in spent fuel pool cooling and cleanup systems (BWR and PWR) exposed to treated water or treated borated water. The GALL Report recommends that a plant-specific AMP be evaluated to determine and assess the qualified life of the linings in the environment to ensure that these aging effects are adequately managed.

By letter dated June 11, 2008, the applicant amended LRA Table 3.3.2-19-9-IP3 to state that elastomer expansion joints exposed internally to treated water with an aging effect of cracking and change in material properties will be managed by the Periodic Surveillance and Maintenance Program. The applicant referenced LRA Table 3.3.1, Line Item 3.3.1-12.

The staff confirmed that change in material properties of elastomer exposed to treated water is managed by the Periodic Surveillance and Preventive Maintenance Program. The staff also verified that the AMP includes periodic visual inspections of a representative sample of interior and exterior elastomer surfaces to detect the effects of aging before they could affect a component’s ability to accomplish its intended function.

Based on the programs identified above, the staff concludes that the applicant’s programs meet SRP-LR Section 3.3.2.2.5 criteria. For those line items that apply to LRA Section 3.3.2.2.5, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.6 Reduction of Neutron-Absorbing Capacity and Loss of Material Due to General Corrosion

The staff reviewed LRA Section 3.3.2.2.6 against the criteria in SRP-LR Section 3.3.2.2.6.

LRA Section 3.3.2.2.6 addresses reduction of neutron-absorbing capacity and loss of material due to general corrosion in Boral spent fuel storage racks exposed to a treated borated water environment, stating that the Boral Surveillance Program uses coupon samples to manage these aging effects by periodically monitoring physical and chemical properties of the absorber material. The Boral Surveillance Program is supplemented by the Water Chemistry Control - Primary and Secondary Program.

SRP-LR Section 3.3.2.2.6 states that reduction of neutron-absorbing capacity and loss of material due to general corrosion may occur in the neutron-absorbing sheets of BWR and PWR spent fuel storage racks exposed to treated water or treated borated water. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that these aging effects are adequately managed.

The staff confirmed that reduction of neutron-absorbing capacity and loss of material due to general corrosion in Boral spent fuel storage racks exposed to a treated borated water environment is adequately managed by the Boral Surveillance Program and Water Chemistry Control - Primary and Secondary Program. The staff also verified that the program includes the use of periodic coupon samples to monitor the physical and chemical properties of the absorber material.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.6 criteria. For those line items that apply to LRA Section 3.3.2.2.6, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.7 Loss of Material Due to General, Pitting, and Crevice Corrosion

The staff reviewed LRA Section 3.3.2.2.7 against the criteria in SRP-LR Section 3.3.2.2.7.

(1) LRA Section 3.3.2.2.7(1) addresses steel piping and components in auxiliary systems exposed to lubricating oil and managed by the Oil Analysis Program, which periodically samples and analyzes lubricating oil to maintain contaminants within acceptable limits and preserve an environment not conducive to corrosion. The One-Time Inspection Program will use visual inspection or nondestructive examination of representative samples to confirm the effectiveness of the Oil Analysis Program in managing aging effects for components that credit it. Steel piping components and tanks of the reactor coolant pump oil collection system are not exposed continuously to a lubricating oil environment maintained by the Oil Analysis Program and do not credit it for managing loss of material. Instead these components are managed by the One-Time Inspection Program, which will use visual or volumetric NDE techniques to inspect a representative sample of the internal surfaces for significant corrosion.

    SRP-LR Section 3.3.2.2.7 states that loss of material due to general, pitting, and crevice corrosion may occur in steel piping, piping components, and piping elements, including the tubing, valves, and tanks in the reactor coolant pump oil collection system, exposed to lubricating oil (as part of the fire protection system). The existing AMP periodically samples and analyzes lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment not conducive to corrosion. However, control of lube oil contaminants may not always be fully effective in precluding corrosion; therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the lubricating oil program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that component intended functions will be maintained during the period of extended operation. In addition, corrosion may occur at locations in the reactor coolant pump oil collection tank where water from wash-downs may accumulate; therefore, the effectiveness of the program should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to manage loss of material due to general, pitting, and crevice corrosion, including determination of the thickness of the lower portion of the tank. A one-time inspection is an acceptable method to ensure that corrosion does not occur and that component intended functions will be maintained during the period of extended operation.

The staff confirmed that the Oil Analysis Program and One-Time Inspection Program will manage the loss of material due to general, pitting, and crevice corrosion in steel piping and related components of auxiliary systems exposed to lubricating oil. The staff also verified that the Oil Analysis Program includes periodic sampling and analysis to ensure contaminants are maintained within acceptable limits, and that the effectiveness of this program will be confirmed by the One-Time Inspection Program which includes visual inspections or non-destructive examinations to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

The staff also verified that the effects of aging on steel piping components and tanks of the reactor coolant pump oil collection system will be adequately managed. The tanks and piping components are not continuously exposed to a lubricating oil environment. Loss of material in these components is managed by the One-Time Inspection Program which includes visual inspections and NDE techniques to inspect a representative sample of the internal surfaces to assure there is no significant corrosion. During an audit, the staff asked the applicant to identify what actions will be taken if degradation is discovered by the One-Time Inspection Program (Audit Item 218). In its response, dated December 18, 2007, the applicant stated that, in addition to verifying the effectiveness of an AMP, the One-Time Inspection Program is utilized to confirm the absence of an aging effect where either (a) an aging effect is not expected to occur but there is insufficient data to completely rule it out, or (b) an aging effect is expected to progress very slowly. For the RCP oil collection system, the applicant stated that the One-Time Inspection Program will confirm that either the aging effect is not occurring, or the aging effect is occurring very slowly as not to affect component intended functions. In either event, the One-Time Inspection Program serves as the means of detecting aging effects and triggering additional action in response to any adverse findings. The staff confirmed that any unacceptable inspection findings identified during the One-Time Inspection Program will be evaluated in accordance with the site corrective action process to determine the need for subsequent (including periodic) inspections and for monitoring and trending the results.

Since a one time inspection of RCP oil collection system components after over 30 years of operation will provide valid information regarding whether ongoing periodic inspections through the period of extended operation is warranted, the staff finds that this is an acceptable method of ensuring that the intended functions of RCP oil collection system components will be maintained during the period of extended operation.

(2) LRA Section 3.3.2.2.7 addresses loss of material due to general, pitting, and crevice corrosion in steel components in the BWR reactor water cleanup and shutdown cooling systems exposed to treated water, stating that this aging effect is not applicable to IP, which are PWRs.

SRP-LR Section 3.3.2.2.7 states that loss of material due to general, pitting, and crevice corrosion may occur in steel piping, piping components, and piping elements in the BWR reactor water cleanup and shutdown cooling systems exposed to treated water.

IP2 and IP3 are PWRs and do not have reactor water cleanup and shutdown cooling systems. This item is not applicable to IP.

(3) LRA Section 3.3.2.2.7(3) addresses loss of material due to general (steel only) pitting and crevice corrosion for carbon steel and stainless steel diesel exhaust piping and components exposed to diesel exhaust in the EDG, Appendix R diesel generator, and security generator systems, stating that the Periodic Surveillance and Preventive Maintenance Program manages this aging effect for these components by periodic visual inspections. Additionally, the One-Time Inspection Program will inspect a representative sample of the internal surfaces of EDG system stainless steel components by visual or volumetric NDE techniques. The Fire Protection Program by visual inspections manages loss of material from fire protection system carbon steel diesel exhaust piping and components. These inspections in the Periodic Surveillance and Preventive Maintenance, One-Time Inspection, and Fire Protection programs will manage the aging effect of loss of material so component intended functions will not be affected.

SRP-LR Section 3.3.2.2.7 states that loss of material due to general (steel only), pitting, and crevice corrosion may occur in steel and stainless steel diesel exhaust piping, piping components, and piping elements exposed to diesel exhaust. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that the aging effect is adequately managed.

The staff confirmed that the Periodic Surveillance and Preventive Maintenance, One-Time Inspection, and Fire Protection Programs will adequately manage the loss of material due to general (steel only) pitting and crevice corrosion for carbon steel and stainless steel diesel exhaust piping and components exposed to diesel exhaust in the EDG, Appendix R Diesel Generator, and security generator systems. Specifically, loss of material is managed by periodic visual inspections performed under the Periodic Surveillance and Preventive Maintenance Program. For stainless steel components of the emergency diesel generator systems, the effectiveness of the Periodic Surveillance and Preventive Maintenance Program is verified by the One-time Inspection Program to ensure that loss of material is not occurring, and that the component's intended function will be maintained during the period of extended operation. Loss of material in carbon steel diesel exhaust piping and components of the Appendix R Diesel Generator is managed by the Fire Protection Program which includes visual inspections of the diesel exhaust piping and components. The staff verified that the One-Time Inspection and Fire Protection Programs will manage the loss of material such that the intended function of the Appendix R Diesel Generator exhaust piping components will not be affected.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.7 criteria. For those line items that apply to LRA Section 3.3.2.2.7, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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

The staff reviewed LRA Section 3.3.2.2.8 against the criteria in SRP-LR Section 3.3.2.2.8.

LRA Section 3.3.2.2.8 addresses loss of material due to general, pitting, and crevice corrosion, and MIC for carbon steel (with or without coating or wrapping) piping and components buried in soil in the auxiliary systems, stating that the Buried Piping and Tanks Inspection Program manages this aging effect by (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel components. Buried components will be inspected when excavated during maintenance. There will be inspections within ten years before the period of extended operation and within the first ten years of the period unless opportunistic inspections occur within these ten-year periods. This program will manage the aging effect of loss of material so component intended functions will not be affected.

SRP-LR Section 3.3.2.2.8 states that loss of material due to general, pitting, and crevice corrosion, and MIC may occur in steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil. Buried piping and tanks inspection programs rely on industry practice, frequency of pipe excavation, and operating experience to manage the effects of loss of material from general, pitting, and crevice corrosion and MIC. The effectiveness of the buried piping and tanks inspection program should be verified to evaluate an applicant's inspection frequency and operating experience with buried components, ensuring that loss of material does not occur.

The staff confirmed that the Buried Piping and Tanks Inspection Program will adequately manage the loss of material due to general, pitting, and crevice corrosion, and MIC which may occur in steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil. The staff also verified that the effectiveness of this AMP will be confirmed by inspection of buried components when excavated during maintenance. In addition, an inspection will be performed within ten years of entering the period of extended operation and within ten years after entering the period of extended operation, unless an opportunistic inspection occurred within these ten-year periods.

During the audit the staff requested the applicant to describe the operating experience it had in the area of handling buried steel piping, piping components, piping elements, and tanks (with or without coating or wrapping) exposed to soil and how this plant specific and industry operating experience is planned to be evaluated and utilized in the developing this program (Audit Item 242). In its response, dated December 18, 2007, the applicant stated that since 2000, two condition reports were initiated as a result of underground leaks, and that the piping in both cases was nonsafety-related and not in the scope of license renewal. The applicant also stated that no other buried piping repair or replacement was identified during its review of operating experience and that the Buried Piping and Tanks Inspection Program will be implemented consistent with the corresponding program described in the Gall Report, Section XI.M34, Buried Piping and Tanks Inspection.

Based on the program identified above, the staff concludes that the applicant's program meets SRP-LR Section 3.3.2.2.8 criteria. For those line items that apply to LRA Section 3.3.2.2.8, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.9 Loss of Material Due to General, Pitting, Crevice, Microbiologically-Influenced Corrosion and Fouling

The staff reviewed LRA Section 3.3.2.2.9 against the criteria in SRP-LR Section 3.3.2.2.9.

(1) LRA Section 3.3.2.2.9 (1) addresses loss of material due to general, pitting, and crevice corrosion, and MIC for carbon steel piping and components exposed to fuel oil, stating that the Diesel Fuel Monitoring Program manages these components by sampling and monitoring fuel oil quality for whether it remains within the limits specified by the ASTM standards. Maintaining parameters within limits prevents significant loss of material. The One-Time Inspection Program will use visual inspection or NDE of representative samples to confirm the effectiveness of the Diesel Fuel Monitoring Program in managing aging effects for components that credit it.

    SRP-LR Section 3.3.2.2.9 states that loss of material due to general, pitting, and crevice corrosion, MIC, and fouling may occur in steel piping, piping components, piping elements, and tanks exposed to fuel oil. The existing AMP relies on fuel oil chemistry programs to monitor and control fuel oil contamination to manage loss of material due to corrosion or fouling. Corrosion or fouling may occur at locations where contaminants accumulate. The effectiveness of fuel oil chemistry programs should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to manage loss of material due to general, pitting, and crevice corrosion, MIC, and fouling to verify the effectiveness of fuel oil chemistry programs. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that component intended functions will be maintained during the period of extended operation.

    The staff confirmed that loss of material due to general, pitting, crevice, MIC, and fouling of steel piping, piping components, piping elements, and tanks exposed to fuel oil was managed by the Diesel Fuel Monitoring Program, and that the AMP monitors and controls contamination of fuel oil within limits specified in ASTM standards. In addition, the staff confirmed that the effectiveness of the Diesel Fuel Monitoring Program will be verified by the One-Time Inspection Program, which includes measures to confirm that unacceptable degradation of a component is not occurring and its intended function will be maintained during the period of extended operation. This approach is consistent with the GALL Report and is, therefore, acceptable.

(2) LRA Section 3.3.2.2.9 addresses loss of material due to general, pitting, and crevice corrosion, and MIC for carbon steel heat exchanger components exposed to lubricating oil, stating that the Oil Analysis Program manages this aging effect by periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits and preserve an environment not conducive to corrosion. The One-Time Inspection Program will use visual inspections or NDEs of representative samples to confirm the effectiveness of the Oil Analysis Program in managing aging effects for components that credit it.

SRP-LR Section 3.3.2.2.9 states that loss of material due to general, pitting, and crevice corrosion, MIC, and fouling may occur in steel heat exchanger components exposed to lubricating oil. The existing AMP periodically samples and analyzes lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment not conducive to corrosion. However, control of lube oil contaminants may not always be fully effective in precluding corrosion; therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of lubricating oil programs. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that component intended functions will be maintained during the period of extended operation.

The staff confirmed that loss of material due to general, pitting, and crevice corrosion, MIC, and fouling in steel heat exchanger components exposed to lubricating oil is adequately managed by the existing Oil Analysis Program which includes periodic sampling and analysis to maintain contaminants within acceptable limits. In addition, the staff confirmed that the effectiveness of the Oil Analysis Program will be verified by the One-Time Inspection Program, which includes measures to confirm that corrosion is not occurring and that component intended functions will be maintained during the period of extended operation. This approach is consistent with the GALL Report and is, therefore, acceptable.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.9 criteria. For those line items that apply to LRA Section 3.3.2.2.9, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.10 Loss of Material Due to Pitting and Crevice Corrosion

The staff reviewed LRA Section 3.3.2.2.10 against the criteria in SRP-LR Section 3.3.2.2.10.

(1) LRA Section 3.3.2.2.10 addresses loss of material due to pitting and crevice corrosion in steel piping with elastomer lining exposed to treated borated water, stating that this aging effect is not applicable to IP, which are PWRs.

SRP-LR Section 3.3.2.2.10 states that loss of material due to pitting and crevice corrosion may occur in BWR and PWR steel piping with elastomer lining or stainless steel cladding that are exposed to treated water and treated borated water if the cladding or lining is degraded.

The staff confirmed that there are no elastomer-lined steel components within the scope of license renewal for auxiliary systems. This item does not apply to IP.

(2) LRA Section 3.3.2.2.10 addresses loss of material due to pitting and crevice corrosion in stainless steel and aluminum piping, piping components, and piping elements and in heat exchanger components of stainless steel and of steel with stainless steel cladding exposed to treated water, stating that in the auxiliary systems there are no aluminum

components exposed to treated water. The applicant compares aging management results for loss of material in stainless steel auxiliary system components exposed to treated water to the GALL Report lines for the ESF and steam and power conversion (S&PC) systems considering PWR water chemistry programs because the corresponding line for auxiliary systems considers only BWR chemistry. Consistent with the GALL Report lines for the ESF and S&PC systems, the Water Chemistry Control – Primary and Secondary Program manages loss of material due to pitting and crevice corrosion for stainless steel components exposed to treated water. The One-Time Inspection Program will confirm effectiveness of the program by an inspection of a representative sample of components crediting it, including those in areas of stagnant flow and other susceptible locations.

SRP-LR Section 3.3.2.2.10 states that loss of material due to pitting and crevice corrosion may occur in stainless steel and aluminum piping, piping components, piping elements, and for stainless steel and steel with stainless steel cladding heat exchanger components exposed to treated water. The existing AMP monitors and controls reactor water chemistry to manage the aging effects of loss of material from pitting and crevice corrosion. However, high concentrations of impurities in crevices and with stagnant flow conditions may cause pitting or crevice corrosion; therefore, the effectiveness of water chemistry control programs should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to manage loss of material from pitting and crevice corrosion to verify the effectiveness of water chemistry control programs. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that component intended functions will be maintained during the period of extended operation.

The staff confirmed that there are no aluminum piping components exposed to treated water in the auxiliary systems and that the loss of material due to pitting and crevice corrosion of stainless steel piping, piping components, piping elements, and stainless steel and steel with stainless steel cladding heat exchanger components exposed to treated water is adequately managed by the existing Water Chemistry Control Primary – Secondary Program which monitors and controls reactor water chemistry. In addition, the staff confirmed that the effectiveness of the Water Chemistry Program will be verified by the One-Time Inspection Program, which includes measures to confirm that corrosion is not occurring and that component intended functions will be maintained during the period of extended operation. This approach is consistent with the GALL Report and is, therefore, acceptable.

(3) LRA Section 3.3.2.2.10 addresses loss of material due to pitting and crevice corrosion for copper alloy components exposed to condensation (external) in the HVAC and other systems, stating that the External Surfaces Monitoring and Periodic Surveillance and Preventive Maintenance programs manage this aging effect by periodic visual inspections and other NDE techniques so component intended functions will not be affected.

SRP-LR Section 3.3.2.2.10 states that loss of material due to pitting and crevice corrosion may occur in copper alloy heating, ventilation, and air conditioning (HVAC) piping, piping components, and piping elements exposed to condensation (external). The GALL Report recommends further evaluation of a plant-specific AMP to ensure that the aging effect is adequately managed.

By letter dated June 12, 2009, the applicant amended its LRA to state that copper alloy tubing exposed externally to condensation has the aging effect of loss of material in the Service Water System. For these AMR line items the applicant proposed the External Surfaces Monitoring Program.

The staff confirmed that loss of material due to pitting and crevice corrosion for copper alloy components exposed to condensation (external) in the HVAC and other systems is adequately managed by the existing External Surfaces Monitoring and Periodic Surveillance and Preventive Maintenance AMPs. The staff also verified that these programs include periodic visual inspections and NDE techniques to confirm that the intended function of components is not affected. This approach is consistent with the GALL Report and is, therefore, acceptable.

(4) LRA Section 3.3.2.2.10 addresses loss of material due to pitting and crevice corrosion for copper alloy components exposed to lubricating oil in auxiliary systems, stating that the Oil Analysis Program manages this aging effect by periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits and preserve an environment not conducive to corrosion. The One-Time Inspection Program will use visual inspections or NDEs of representative samples to confirm the effectiveness of the Oil Analysis Program in managing aging effects for components that credit it.

SRP-LR Section 3.3.2.2.10 states that loss of material due to pitting and crevice corrosion may occur in copper alloy piping, piping components, and piping elements exposed to lubricating oil. The existing AMP periodically samples and analyzes lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment not conducive to corrosion. However, control of lube oil contaminants may not always be fully effective in precluding corrosion; therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of lubricating oil programs. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that component intended functions will be maintained during the period of extended operation.

The staff confirmed that the existing Oil Analysis Program adequately manages loss of material in copper alloy piping components exposed to lubricating oil by periodic sampling and analysis to maintain oil contaminants within acceptable limits. In addition, the staff confirmed that the effectiveness of the Oil Analysis Program will be verified by the One-Time Inspection Program, which includes measures to confirm that corrosion is not occurring and that component intended functions will be maintained during the period of extended operation. This approach is consistent with the GALL Report and is, therefore, acceptable.

(5) LRA Section 3.3.2.2.10 addresses loss of material due to pitting and crevice corrosion for aluminum piping and components and stainless steel components exposed to condensation, stating that this aging effect requires management for HVAC and other systems. The Bolting Integrity, External Surfaces Monitoring, Periodic Surveillance and Preventive Maintenance, and One-Time Inspection programs will manage loss of

material in aluminum or stainless steel components exposed internally or externally to condensation by periodic visual inspection with the Periodic Surveillance and Preventive Maintenance Program using other NDE techniques as appropriate to manage loss of component material.

SRP-LR Section 3.3.2.2.10 states that loss of material due to pitting and crevice corrosion may occur in HVAC aluminum piping, piping components, and piping elements and stainless steel ducting and components exposed to condensation. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that the aging effect is adequately managed.

By letter dated June 12, 2009, the applicant amended its LRA to state that stainless steel bolting that is externally exposed to condensation has the aging effect of loss of material in the Service Water System. For this AMR line item the applicant proposed the Bolting Integrity Program. In the same letter the applicant amended its LRA to state that stainless steel piping, tubing and valve bodies exposed externally to condensation have an aging effect of loss of material in the Service Water System. For these AMR line items the applicant proposed the External Surfaces Monitoring Program.

The staff confirmed that the Bolting Integrity, External Surfaces Monitoring, One-Time Inspection, and Periodic Surveillance and Preventive Maintenance AMPs adequately manage the loss of material due to pitting and crevice corrosion for aluminum piping and components and stainless steel components exposed to condensation. The staff also verified that these programs include periodic visual inspections and NDE techniques to manage loss of component material and confirm that their intended function is not affected. This approach is consistent with the GALL Report and is, therefore, acceptable.

(6) LRA Section 3.3.2.2.10 addresses loss of material due to pitting and crevice corrosion in copper alloy fire protection system piping, piping components, and piping elements exposed to internal condensation, stating that at IP, there are no copper alloy components exposed to condensation in the fire protection systems. However, this item can be applied to copper alloy components exposed to internal condensation in other systems. The Periodic Surveillance and Preventive Maintenance Program will manage loss of material in copper alloy components exposed internally to condensation, through the use of periodic visual inspections or other NDE techniques.

SRP-LR Section 3.3.2.2.10 states that loss of material due to pitting and crevice corrosion may occur in copper alloy fire protection system piping, piping components, and piping elements exposed to internal condensation. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that the aging effect is adequately managed.

By letter dated June 12, 2009, the applicant amended its LRA to state that copper alloy >15% Zn heat exchanger tubes that are internally exposed to condensation have the aging effect of loss of material in the Instrument Air System. For these AMR line items the applicant proposed the Periodic Surveillance and Preventive Maintenance Program. In the same letter the applicant amended its LRA to state that copper alloy tubing and valve bodies that are internally exposed to condensation have the aging effect of loss of material in the IP1 Station Air System. For these AMR line items the applicant proposed the Periodic Surveillance and Preventive Maintenance Program.

The staff confirmed that there are no copper alloy components exposed to condensation in the fire protection systems and that loss of material due to pitting and crevice corrosion in copper alloy components of other systems that are exposed to internal condensation is adequately managed by the Periodic Surveillance and Preventive Maintenance Program which includes periodic visual inspections and NDE techniques to manage loss of component material and confirm that the intended function of components is not affected. This approach is consistent with the GALL Report and is, therefore, acceptable.

(7) LRA Section 3.3.2.2.10 addresses loss of material due to pitting and crevice corrosion in stainless steel piping, piping components, and piping elements exposed to soil, stating that this aging effect is not applicable because at IP, there are no stainless steel piping components exposed to soil in the auxiliary systems.

SRP-LR Section 3.3.2.2.10 states that loss of material due to pitting and crevice corrosion may occur in stainless steel piping, piping components, and piping elements exposed to soil.

The staff verified that there are no stainless steel piping components exposed to soil in the auxiliary systems. This item is not applicable to IP.

(8) LRA Section 3.3.2.2.10 addresses loss of material due to pitting and crevice corrosion in stainless steel piping, piping components, and piping elements of the BWR Standby Liquid Control System that are exposed to sodium pentaborate solution, stating that this aging effect is not applicable to IP, which are PWRs.

SRP-LR Section 3.3.2.2.10 states that loss of material due to pitting and crevice corrosion may occur in stainless steel piping, piping components, and piping elements of the BWR standby liquid control system exposed to sodium pentaborate solution.

IP2 and IP3 are PWRs and do not have Standby Liquid Control Systems. The staff agrees that this item is not applicable to IP.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.10 criteria. For those line items that apply to LRA Section 3.3.2.2.10, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.11 Loss of Material Due to Pitting, Crevice, and Galvanic Corrosion

The staff reviewed LRA Section 3.3.2.2.11 against the criteria in SRP-LR Section 3.3.2.2.11.

LRA Section 3.3.2.2.11 addresses loss of material in copper alloy auxiliary system components exposed to a BWR treated water environment, stating that this aging effect is not applicable to IP, which are PWRs.

SRP-LR Section 3.3.2.2.11 states that loss of material due to pitting, crevice, and galvanic corrosion may occur in copper alloy piping, piping components, and piping elements exposed to treated water.

This item pertains to loss of material in copper alloy auxiliary system components exposed to a BWR treated water environment. IP2 and IP3 are PWRs. The staff agrees that this item is not applicable to IP.

Based on the above, the staff concludes that SRP-LR Section 3.3.2.2.11 criteria do not apply.

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

The staff reviewed LRA Section 3.3.2.2.12 against the criteria in SRP-LR Section 3.3.2.2.12.

(1) LRA Section 3.3.2.2.12 addresses loss of material due to pitting and crevice corrosion, and MIC in stainless steel and copper alloy piping and components exposed to fuel oil, stating that the Diesel Fuel Monitoring Program manages this aging effect for most of these components. There are no aluminum components exposed to fuel oil in the auxiliary systems. The Diesel Fuel Monitoring Program samples and monitors fuel oil quality for whether it remains within the limits specified by ASTM standards. Maintaining parameters within limits prevents significant loss of material. The One-Time Inspection Program will use visual inspections or NDEs of representative samples to confirm the effectiveness of the Diesel Fuel Monitoring Program in managing aging effects for components that credit it. The Periodic Surveillance and Preventive Maintenance Program will manage loss of material for the stainless steel components of the emergency fuel oil trailer transfer tank by periodic visual inspections.

SRP-LR Section 3.3.2.2.12 states that loss of material due to pitting and crevice corrosion, and MIC may occur in stainless steel, aluminum, and copper alloy piping, piping components, and piping elements exposed to fuel oil. The existing AMP relies on the fuel oil chemistry program for monitoring and control of fuel oil contamination to manage loss of material due to corrosion; however, corrosion may occur at locations where contaminants accumulate and the effectiveness of fuel oil chemistry control should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the fuel oil chemistry control program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that component intended functions will be maintained during the period of extended operation.

The staff confirmed that there are no aluminum components exposed to fuel oil in the auxiliary systems. In addition, the staff verified that the loss of material due to pitting and crevice corrosion, and MIC in stainless steel and copper alloy piping, piping components, and piping elements exposed to fuel oil is managed by the Diesel Fuel Monitoring Program and that the program includes sampling and monitoring of fuel oil to ensure it remains within limits specified in ASTM standards. In addition, the staff confirmed that the effectiveness of the Diesel Fuel Monitoring Program will be verified by the One Time Inspection Program, which includes measures to confirm that loss of material is not occurring and that component intended functions will be maintained during the period of extended operation. For the stainless steel components of the emergency fuel oil trailer transfer tank, loss of material will be managed by periodic visual inspections performed in accordance with the Periodic Surveillance and Preventive Maintenance Program. This approach is consistent with the GALL Report and is, therefore, acceptable.

(2) LRA Section 3.3.2.2.12 addresses loss of material due to pitting and crevice corrosion, and MIC in most stainless steel piping and components exposed to lubricating oil, stating that the Oil Analysis Program manages this aging effect by periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits and preserve an environment not conducive to corrosion. The One-Time Inspection Program will use visual inspections or NDEs of representative samples to confirm the effectiveness of the Oil Analysis Program in managing aging effects for components that credit it. Stainless steel piping components of the reactor coolant pump oil collection system are not exposed continuously to a lubricating oil environment maintained by the Oil Analysis Program and do not credit it for managing loss of material. Instead the One-Time Inspection Program manages these components by using visual or volumetric NDE techniques to inspect a representative sample of the internal surfaces for significant corrosion.

SRP-LR Section 3.3.2.2.12 states that loss of material due to pitting, crevice, and MIC may occur in stainless steel piping, piping components, and piping elements exposed to lubricating oil. The existing program periodically samples and analyzes lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment not conducive to corrosion. However, control of lube oil contaminants may not always be fully effective in precluding corrosion; therefore, the effectiveness of lubricating oil control should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of lubricating oil programs. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that component intended functions will be maintained during the period of extended operation.

The staff confirmed that loss of material due to pitting, crevice, and MIC in most stainless steel piping and components exposed to lubricating oil is managed by the Oil Analysis Program which includes periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits. In addition, the staff confirmed that the effectiveness of the Oil Analysis Program will be verified by the One Time Inspection Program, which includes measures to confirm that loss of material is not occurring and that component intended functions will be maintained during the period of extended operation.

Since stainless steel piping components of the reactor coolant pump oil collection system are not continuously exposed to a lubricating oil environment the Oil Analysis Program is not credited to manage the effects of aging. For these components, the staff verified that the absence of significant corrosion will be confirmed by the One-Time Inspection Program which includes NDE techniques to inspect a representative sample of the internal surfaces.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.3.2.2.12 criteria. For those line items that apply to LRA Section 3.3.2.2.12, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.13 Loss of Material Due to Wear

The staff reviewed LRA Section 3.3.2.2.13 against the criteria in SRP-LR Section 3.3.2.2.13.

LRA Section 3.3.2.2.13 addresses loss of material due to wear in the elastomer seals and components exposed to air - indoor uncontrolled (internal or external), stating that this aging effect is not applicable because at IP, in the auxiliary systems, the expansion joints are fixed at both ends and do not contact any other components such that wear could occur.

SRP-LR Section 3.3.2.2.13 states that loss of material due to wear may occur in the elastomer seals and components exposed to air - indoor uncontrolled (internal or external). The GALL Report recommends further evaluation to ensure that the aging effect is adequately managed.

The staff confirmed that expansion joints in the auxiliary system are fixed at both ends and do not contact any other components. Because of this configuration, the staff agrees that that wear in the elastomer seals can not occur. However, change in material properties and cracking of elastomer components are managed by the Periodic Surveillance and Preventive Maintenance Program. Since wear can not occur, loss of material due to wear in the elastomer seals is not applicable to IP auxiliary systems.

Based on the above, the staff concludes that SRP-LR Section 3.3.2.2.13 criteria do not apply.

3.3.2.2.14 Loss of Material Due to Cladding Breach

The staff reviewed LRA Section 3.3.2.2.14 against the criteria in SRP-LR Section 3.3.2.2.14.

LRA Section 3.3.2.2.14 addresses cracking due to underclad cracking in PWR steel charging pump casings with stainless steel cladding exposed to treated borated water, stating that this aging effect is not applicable because the charging pump casings are not clad but made of stainless steel.

SRP-LR Section 3.3.2.2.14 states that loss of material due to cladding breach (also referred to as underclad cracking may occur in PWR steel charging pump casings with stainless steel cladding exposed to treated borated water. The GALL Report references IN 94-63 and recommends further evaluation of a plant-specific AMP to ensure that the aging effect is adequately managed.

The staff confirmed that the charging pump casings at IP are made of stainless steel and are not clad. This item is not applicable to IP.

Based on the above, the staff concludes that SRP-LR Section 3.3.2.2.14 criteria do not apply.

3.3.2.2.15 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff’s evaluation of the applicant’s QA program.

3.3A.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.3.2-1-IP2 through 3.3.2-18-IP2 and 3.3.2-19-1-IP2 through 3.3.2-19-44-IP2, 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-IP2 through 3.3.2-18-IP2 and 3.3.2-19-1-IP2 through 3.3.2-19-44-IP2, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information about how it will manage the aging effects. Specifically, note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation. The staff's evaluation is documented in the following sections.

3.3A.2.3.1 Service Water System - Summary of Aging Management Review – LRA Table 3.3.2-2-IP2

The staff reviewed LRA Table 3.3.2-2-IP2, which summarizes the results of AMR evaluations for the service water system component groups.

The LRA table referenced Note F for titanium material used in heat exchanger shells and tubes internally and externally exposed to raw water are subject to cracking, fouling, and loss of material which are managed by the Service Water Integrity Program. The staff's review of the Service Water Integrity Program is documented in SER Section 3.0.3.1.14. Titanium components are not addressed in the GALL Report. However, as stated in the Metals Handbook Desk Edition, copyright 1985, by the American Society for Metals, titanium is a corrosion resistant material; therefore, the applicant is conservative in addressing the aging effects of concern for titanium heat exchanger components. The Service Water Integrity Program inspects components for erosion, corrosion, and biofouling to confirm the heat transfer capability of safety-related heat exchangers cooled by service water. Chemical treatment with biocides and sodium hypochlorite and periodic cleaning and flushing of loops infrequently used are methods for controlling fouling within the heat exchangers and managing loss of material in service water components.

On the basis of its review, including the applicant's plant-specific operating experience, the staff finds that the aging effects of cracking, fouling, and loss of material of titanium material used in heat exchanger shells and tubes exposed to raw water will be adequately managed by the Service Water Integrity Program.

The LRA table also referenced Note F for titanium heat exchanger tubes externally exposed to treated water with loss of material as the aging effect, and Water Chemistry Control – Primary and Secondary Program as the AMP. The staff's evaluation of this program is documented in SER Section 3.0.3.2.17. The program includes periodic monitoring and control of known detrimental contaminants such as chlorides, fluorides, dissolved oxygen, and sulfate concentrations below the levels known to result in loss of material or cracking. Water chemistry control is in accordance with industry guidelines such as EPRI TR-105714 for primary water chemistry, and EPRI TR-102134 for secondary water chemistry. The One-Time Inspection Program for Water Chemistry utilizes inspections or NDEs of representative samples to verify that the Water Chemistry Control – Primary and Secondary Program has been effective at managing aging effects. Because chemistry will be monitored, and the One-Time Inspection Program will verify the effectiveness of the water chemistry control, the staff finds the applicant's AMR results for this material/environment combination acceptable.

The LRA table referenced Note F for titanium heat exchanger shell externally exposed to condensation with no aging effect and no AMP. The staff notes that in LRA Table 3.3.2-9-IP2, the applicant uses Note F for the same material/environment combination, but cites an aging effect of loss of material and states that it will be managed by the Periodic Surveillance and Preventive Maintenance Program. This appears to be a discrepancy. This was identified as Open Item 3.3-1.

By letter dated January 27, 2009, the applicant stated that LRA Table 3.3.2-2-IP2 is correct for the titanium heat exchanger shell externally exposed to condensation with no aging effect and no AMP, and that LRA Table 3.3.2-9-IP2 was corrected to be consistent with Table 3.3.2-2-IP2. According to the Metals Handbook Desk Edition, copyright 1985, by the American Society for Metals, titanium is extremely resistant to corrosion in many aggressive environments. The Metals Handbook also states that resistance to general corrosion has been ascribed to a thin, inert film that forms rapidly on the surface when titanium is exposed to air and to passive films that form on the surface in certain aggressive media. Because titanium is a highly corrosion resistant material, and the environment (condensation) is not corrosive or aggressive, the staff finds the applicant's AMR results to be acceptable. Thus, Open Item 3.3-1, with respect to the different aging effects for the same environment, is closed.

The LRA table referenced Note G for nickel alloy valve bodies externally exposed to condensation having an aging effect of loss of material and using the External Surfaces Monitoring Program to manage the effects of aging. SER Section 3.0.3.2.5 documents the staff's review of the External Surfaces Monitoring Program. While the GALL Report does not contain this specific material/environment combination, a similar material/environment combinations exists in GALL Report with loss of material as the aging effect that use the External Surfaces Monitoring AMP to manage the effects of aging (e.g., GALL Report Tables V.C, V.E, and VII.I, Line items V.C-2, V.E-10, VII.I-11, respectively). The External Surfaces Monitoring Program manages aging effects through visual inspection of external surfaces for evidence of material loss. Because periodic inspections of the external surfaces of the valve bodies will be performed, the staff finds the applicant's AMR results acceptable.

The LRA table referenced Note H for copper alloy >15 percent zinc (inhibited) heat exchanger tubes exposed to treated water (external) with an aging effect of loss of material-wear managed by the Service Water Integrity Program. As noted above, the program includes component inspections for erosion, corrosion, and biofouling to verify the heat transfer capability of safety-related heat exchangers cooled by service water. Because the heat exchanger tubes will be periodically inspected for loss of material, the staff finds the applicant's AMR results acceptable.

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

3.3A.2.3.2 Component Cooling Water System - Summary of Aging Management Review – LRA Table 3.3.2-3-IP2

The staff reviewed LRA Table 3.3.2-3-IP2, which summarizes the results of AMR evaluations for the component cooling water system component groups.

The LRA table referenced Note F for aluminum bronze material used in a heat exchanger tubesheet Internally exposed to raw water and externally exposed to treated water with the aging effect being loss of material. The AMPs for the raw water environment are the Selective Leaching and Service Water Integrity Programs, and the AMPs for the treated water environment are the Selective Leaching and the Water Chemistry Control-Closed Cooling Water Programs. The staff's review of these programs is documented in SER Sections 3.0.3.1.13 (Selective Leaching Program), 3.0.3.1.14 (Service Water Integrity Program), and 3.0.3.2.16 (Water Chemistry Control-Closed Cooling Water Program).

Loss of material in both environments will be managed by the Selective Leaching Program which will include a one-time visual inspection, hardness measurement (where feasible based on form and configuration) or other industry-accepted mechanical inspection techniques of selected components that may be susceptible to selective leaching to determine whether loss of material due to selective leaching has occurred and whether the process will affect component ability to perform intended functions through the period of extended operation.

The Service Water Integrity Program will also manage the loss of material for the raw water (internal) environment. The Service Water Integrity Program inspects components for erosion, corrosion, and biofouling to confirm the heat transfer capability of safety-related heat exchangers cooled by service water. Chemical treatment with biocides and sodium hypochlorite and periodic cleaning and flushing of loops infrequently used are methods for controlling fouling within the heat exchangers and managing loss of material in service water components.

The GALL Report does not address components made of aluminum bronze material specifically. However, in Table IX.C of the GALL Report, aluminum bronze material is addressed in the discussion of copper alloy components. Table IX.C states that aluminum bronze < 8 percent aluminum components are resistant to SCC, selective leaching and pitting and crevice corrosion, and aluminum bronze components > 8 percent aluminum may be susceptible to the aforementioned aging effects. The applicant conservatively assumed that the aluminum bronze contains > 8 percent aluminum, which implies that SCC is a potential aging effect.

The Water Chemistry Control-Closed Cooling Water Program will manage the loss of material for the treated water (external) environment as well as SCC. The Water Chemistry Control - Closed Cooling Water Program includes preventive measures that manage loss of material, cracking, or fouling for components in closed cooling water systems. This program also includes performance of periodic visual inspections which are capable of detecting SCC.

The staff finds that the applicant's AMR results for aluminum bronze material credit appropriate AERMs and AMPs. The staff's review of the referenced AMPs has verified that the aging effect identified will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation and is therefore acceptable.

The LRA table referenced Note H for heat exchanger (tubes) constructed from copper alloy >15 percent zinc (inhibited) exposed to treated water (external) having the aging effect loss of material–wear that is managed by the Heat Exchanger Monitoring and the Service Water Integrity AMPs. The aging effect identified in the GALL Report for this material/environment is loss of material, which is addressed by another line item in LRA Table 3.3.2-3-IP2. The aging effect identified in the LRA is in addition to that prescribed by the GALL Report. The Heat Exchanger Monitoring Program uses visual or other NDE techniques to inspect heat exchangers for loss of material. The Service Water Integrity Program inspects components for erosion, corrosion, and biofouling to confirm the heat transfer capability of safety-related heat exchangers cooled by service water. Chemical treatment with biocides and sodium hypochlorite and periodic cleaning and flushing of loops infrequently used are methods for controlling fouling within the heat exchangers and managing loss of material in SW components. The staff's review of the referenced AMPs has verified that the aging effect identified will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation and is therefore acceptable.

The LRA table referenced Note H for stainless steel heat exchanger (tubes) exposed to treated water (external) with an aging effect of loss of material-wear that is managed by the Heat Exchanger Monitoring Program. The aging effect identified in the GALL Report for this material/environment is loss of material, which is addressed by another line item in LRA Table 3.3.2-3-IP2. The aging effect identified in the LRA is in addition to that prescribed by the GALL Report. The Heat Exchanger Monitoring Program uses visual or other NDE techniques to inspect heat exchangers for loss of material. The staff's review of the referenced AMP has verified that the aging effect identified will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation and is therefore acceptable.

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

3.3A.2.3.3 Chemical and Volume Control System - Summary of Aging Management Review – LRA Table 3.3.2-6-IP2

The staff reviewed LRA Table 3.3.2-6-IP2, which summarizes the results of AMR evaluations for the chemical and volume control system component groups.

The LRA table referenced Note H for heat exchanger (tubes) constructed from copper alloy externally exposed to lube oil and stainless steel externally exposed to treated water, with an aging effect of loss of material–wear managed by the Heat Exchanger Monitoring AMP. The aging effect identified in the LRA is in addition to that prescribed by the GALL Report. The staff's evaluation of the Heat Exchanger Monitoring Program is documented in SER Section 3.0.3.3.3. This program uses visual inspections or other NDE techniques of heat exchangers for loss of material. Because the heat exchanger tubes will be periodically inspected for loss of material, the staff finds the applicant's AMR results acceptable.

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

3.3A.2.3.4 Primary Makeup Water System - Summary of Aging Management Review – LRA Table 3.3.2-7-IP2

The staff reviewed LRA Table 3.3.2-7-IP2, which summarizes the results of AMR evaluations for the primary makeup water system component groups.

The applicant referenced Note G for the stainless steel bolting exposed to outdoor air (external) with the aging effect of loss of material with aging managed with the Bolting Integrity Program

The staff evaluated the Bolting Integrity Program in Section 3.0.3.2.2. This program is recommended in Table 3, Item 43, of the GALL Report to manage the loss of material due to general, pitting, and crevice corrosion in steel bolting exposed to outdoor air (external). Based on the above, the staff finds that the aging effect of the loss of material in these components will be adequately managed by using the Bolting Integrity Program.

The applicant referenced Note G for stainless steel heat exchanger tubes exposed to steam (internal) subjected to cracking and loss of material with aging managed by the Water Chemistry Control-Primary and Secondary. Stainless steel heat exchanger tubes are not specifically addressed in the GALL Report. However, stainless steel piping is with AERMs of cracking and loss of material which is consistent with the applicant's AMR review. The staff's review of the Water Chemistry Control-Primary and Secondary is documented in SER Section 3.0.3.2.17. The Water Chemistry Control - Primary and Secondary Program manages aging effects caused by corrosion and cracking mechanisms. The program monitors and controls reactor water chemistry based on EPRI TR-105714, Revision 5, "Pressurized Water Reactor Primary Water Chemistry Guidelines," and TR-102134, Revision 6, "Pressurized Water Reactor Secondary Chemistry Guidelines." On the basis of its review, the staff found that appropriate AERMs are identified for stainless steel heat exchanger tubes exposed to steam (internal), and that because these components will be inspected periodically, the aging effects of cracking and loss of material will be effectively managed by the Water Chemistry Control-Primary and Secondary.

The applicant referenced Note G for stainless steel tank, piping, and valve bodies exposed to outdoor air (external) with the aging effect of loss of material managed by the External Surfaces Monitoring Program. Stainless steel exposed to outdoor air (external) is not specifically addressed in the GALL Report. However, in Table IX.C of the GALL states that stainless steel material is susceptible to a variety of aging effects and mechanisms, including loss of material due to pitting and crevice corrosion, and cracking due to stress corrosion cracking. The external environment of interest, outdoor air, would not induce SCC in stainless steel material. However, uncontrolled air might result in condensation, therefore, loss of material is an appropriate aging effect to consider. The External Surfaces Monitoring Program inspects external surfaces of components subject to aging management review. The staff's review of the referenced AMP has verified that the aging effect identified will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation and is therefore acceptable.

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

3.3A.2.3.5 Heating, Ventilation and Air Conditioning Systems - Summary of Aging Management Review – LRA Table 3.3.2-8-IP2

The staff reviewed LRA Table 3.3.2-8-IP2, which summarizes the results of AMR evaluations for the HVAC systems component groups.

The applicant referenced Note G for aluminum damper housing exposed to outdoor air (external) with an aging effect of loss of material and an aging management program of External Surfaces Monitoring Program. The staff agrees that the use of the External Surfaces Monitoring Program to manage the loss of material for aluminum damper housing exposed to outdoor air (external) is appropriate because these material/environment combinations exist for other systems in the GALL Report with the same aging management program prescribed.

The applicant referenced Note G for stainless steel ducts, copper alloy tubing, stainless steel tubing, and stainless steel valve bodies exposed to air-indoor (internal) with no aging effects and no aging management program required. These material/environment combinations are similar to combinations in the GALL Report (e.g., Table VII.J, Line Items J-3 and J-18) that indicate there are no aging effects and no AMP is required. Therefore, the staff finds the applicant's AMR results acceptable.

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

3.3A.2.3.6 Containment Cooling and Filtration System - Summary of Aging Management Review – LRA Table 3.3.2-9-IP2

The staff reviewed LRA Table 3.3.2-9-IP2, which summarizes the results of AMR evaluations for the containment cooling and filtration system component groups.

The LRA table, as amended by letter dated January 27, 2009, referenced Note F for titanium material used in a heat exchanger header externally exposed to condensation with the aging effect and AMP listed as "none," and internally exposed to raw water with the aging effect of loss of material to be managed by the Service Water Integrity Program. Titanium components are not addressed in the GALL Report. As noted in SER Section 3.3A.2.3.1, titanium is highly resistant to corrosion. Therefore, the applicant is conservative in addressing the potential aging effect of loss of material for internal exposure of the heat exchanger header. The staff's review of the Service Water Integrity Program is documented in SER Section 3.0.3.1.14. The Service Water Integrity Program inspects components for erosion, corrosion, and biofouling to confirm the heat transfer capability of safety-related heat exchangers cooled by service water. Chemical treatment with biocides and sodium hypochlorite and periodic cleaning and flushing of loops infrequently used are methods for controlling fouling within the heat exchangers and managing loss of material in service water components.

On the basis of its review, the staff finds that, because these components will be inspected periodically, the aging effect of loss of material for titanium heat exchanger headers exposed to condensation (external) and raw water (internal) will be effectively managed by the Periodic Surveillance and Preventive Maintenance Program and the Service Water Integrity Program, respectively.

For stainless steel heat exchanger tubes exposed to condensation (external) the LRA table referenced Notes G and H. For Note G the aging effect is fouling managed by the Service Water Integrity program and for Note H the aging effect of loss of material due to wear which is managed by Periodic Surveillance and Preventive Maintenance Program. Stainless steel components are addressed in the GALL Report with an aging effect of loss of material, therefore, the LRA is conservative in also considering fouling and loss of material due to wear. The Service Water Integrity Program will inspect components for erosion, corrosion, and biofouling to confirm the heat transfer capability of safety-related heat exchangers cooled by service water. Chemical treatment with biocides and sodium hypochlorite and periodic cleaning and flushing of loops infrequently used are methods for controlling fouling within the heat exchangers and managing loss of material in service water components. The Periodic Surveillance and Preventive Maintenance Program will inspect the heat exchanger tubes for loss of material.

On the basis of its review, the staff found that, because these components will be inspected periodically, the aging effect of fouling for stainless steel heat exchanger tubes exposed to condensation (external) will be effectively managed by the Service Water Integrity Program, and the aging effect of loss of material due to wear will be adequately managed by Periodic Surveillance and Preventive Maintenance Program.

The LRA table referenced Note G for copper alloy tubing and copper alloy >15 percent zinc valve bodies exposed to air-indoor (internal) having no aging effect and require no aging management program. The staff agrees that there is no aging effect and no AMP required for copper alloy tubing and copper alloy >15 percent zinc exposed to air-indoor (internal) because these material/environment combinations exist for other systems in the GALL Report that indicate there are no aging effects and no AMP is required.

The LRA table referenced Note H for copper alloy heat exchanger fins exposed to condensation (external) having the aging effect of fouling which is managed by the Service Water Integrity Program. The staff finds the use of the Service Water Integrity Program to manage the effects of fouling acceptable because the program will use inspections to monitor for fouling and will chemically treat the heat exchanger fins to prevent fouling.

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

3.3A.2.3.7 Control Room HVAC System - Summary of Aging Management Review – LRA Table 3.3.2-10-IP2

The staff reviewed LRA Table 3.3.2-10-IP2, which summarizes the results of AMR evaluations for the control room HVAC system component groups.

The LRA table referenced Note G for stainless steel bolting exposed to outdoor air (external) having the aging effects of loss of material which is managed by the Bolting Integrity Program and by the External Surfaces Monitoring Program. The staff's review of the Bolting Integrity Program is documented in SER Section 3.0.3.2.2 and the External Surfaces Monitoring Program is documented in Section 3.0.3.2.5. The Bolting Integrity Program is recommended in Table 3, Item 43, of the GALL Report to manage the loss of material due to general, pitting, and crevice corrosion in steel bolting exposed to outdoor air (external). The External Surfaces Monitoring Program inspects the external surfaces of components subject to an aging management review for loss of material. Based on the above, the staff finds that the aging effect of the loss of material in these components will be adequately managed by using the Bolting Integrity and External Surfaces Monitoring Programs.

The LRA table referenced Note G for elastomer duct flexible connectors exposed to outdoor air (external) and subject to change in material properties and cracking which is managed by the Periodic Surveillance and Preventive Maintenance Program. The staff's evaluation of this program is documented in SER Section 3.0.3.3.7. The GALL Report identifies change in material property as the aging effect for the same material/environment for other systems. The aging effect of cracking is in addition to that prescribed by the GALL Report. The Periodic Surveillance and Preventive Maintenance Program will visually inspect and manually flex a representative sample of duct flexible connections to manage cracking and change in material properties. Based on the above the staff finds that the aging effects will be adequately managed and therefore acceptable.

The LRA table referenced Note G for copper alloy heat exchanger tubes exposed to outdoor air (external) and condensation (external) and have the aging effect of fouling and loss of material which is managed by the Periodic Surveillance and Preventive Maintenance Program. The Periodic Surveillance and Preventive Maintenance program will visually inspect a representative sample of control room HVAC air cooled condensers and evaporators to manage loss of material and fouling. Based on the above the staff finds that the aging effects will be adequately managed and therefore acceptable.

The LRA table referenced Note G for copper alloy piping, tubing and valve bodies exposed to outdoor air (external) with an aging effect of loss of material which is managed by the External Surfaces Monitoring Program. The GALL Report identifies an aging effect of loss of material for copper components exposed to condensation which is a conservative approximation of outdoor air. The staff finds the External Surfaces Monitoring program acceptable to mange the loss of material because the external surfaces will be inspected.

The LRA table referenced Note G for aluminum valve bodies are exposed to treated air (internal) which have no aging effect and no AMP is required The staff agrees that there is no aging effect and no AMP required for aluminum valve bodies exposed to treated air (internal) because these material/environment combinations exist for other systems in the GALL Report that indicate there are no aging effects and no AMP is required.

The LRA table referenced Note G for aluminum heat exchanger fins externally exposed to outdoor air with an aging effect of fouling. The applicant proposed to manage this aging effect for this material/environment combination using the Periodic Surveillance and Preventive Maintenance Program. This program uses periodic visual and other NDEs to inspect the components that are within the scope

On the basis of its review, the staff finds that, because these components will be inspected periodically, the aging effect for these component/environment combinations will be effectively managed by the Bolting Integrity Program, the External Surfaces Monitoring Program, and the Periodic Surveillance and Preventive Maintenance Program.

The LRA table referenced Note H for aluminum heat exchanger fins exposed to condensation (external) with the aging effect of fouling which is managed by the Periodic Surveillance and Preventive Maintenance Program. The Periodic Surveillance and Preventive Maintenance Program will visually inspect a representative sample of control room HVAC air cooled condensers and evaporators to manage loss of material and fouling. Based on the above the staff finds that the aging effects will be adequately managed and therefore acceptable.

The LRA table referenced Note I and plant-specific Note 306, which states “Changes of material properties and cracking in elastomers are results of exposure to ultra-violet light or elevated temperatures (> 95°F). The interior surfaces of these components are not exposed to ultra-violet light and are part of the air intake that is not exposed to elevated temperatures.” The combination is duct flexible connection/elastomer/air–indoor (internal)/none/none. The staff finds that the applicant’s AMR result is appropriate because the elastomer flexible duct connections are not exposed to ultra-violet light or elevated temperatures.

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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3A.2.3.8 Fire Protection - Water System - Summary of Aging Management Review – LRA Table 3.3.2-11-IP2

The staff reviewed LRA Table 3.3.2-11-IP2, which summarizes the results of AMR evaluations for the fire protection - water system component groups.

The LRA table referenced Note G for stainless steel bolting exposed to outdoor air (external) with the aging effect of loss of material which is managed by the Bolting Integrity Program which is reviewed in SER Section 3.0.3.2.2. The Bolting Integrity Program is recommended in Table 3, Item 43, of the GALL Report, Volume 1, to manage the loss of material due to general, pitting, and crevice corrosion in steel bolting exposed to outdoor air (external). Based on the above, the staff finds that the aging effect of the loss of material in these components will be adequately managed by using the Bolting Integrity Program.

The LRA table referenced Note G for copper alloy >15 percent zinc nozzle exposed to air-indoor (internal) which has no aging effect and lists no AMP. This material/environment is similar to other material/environment combinations in the GALL Report (e.g., Table VII.J, Line Item J-3) for which there is no AERM or AMP. Therefore, the staff agrees that there is no aging effect and no AMP required for copper alloy >15 percent zinc nozzle exposed to air-indoor (internal). The staff finds the applicant's AMR results acceptable.

The LRA table referenced Note G for carbon steel tank exposed to concrete (external) with the aging effect of loss of material which is managed by the Aboveground Steel Tank Program. SER Section 3.0.3.2.1 documents the staff's evaluation of the Aboveground Steel Tanks Program. Steel components exposed to concrete are addressed in the GALL Report with no aging effect identified; therefore, the LRA is conservative in assuming an aging effect of loss of material. The staff finds that use of the Aboveground Steel Tanks Program to manage the loss of material for the carbon steel tank exposed to concrete is acceptable because periodic tank inspections are conducted to monitor for loss of material, and thickness measurements of locations that are inaccessible for external visual inspection, such as tank bottom surfaces are performed. Such inspections will ensure that loss of material does not occur.

The LRA table referenced Note H carbon steel expansion joints, carbon steel piping, and carbon steel silencer exposed to exhaust gas (internal) with the aging effect of cracking-fatigue which is managed by the Fire Protection Program. The GALL Report identifies an aging effect for this material/environment combination of loss of material which is addressed by another line item in Table 3.3.2-11-IP2. The aging effect identified in the LRA is in addition to that prescribed by the GALL Report. The staff's review of the Fire Protection Program is documented in SER Section 3.0.3.2.7. The diesel-driven fire pump inspection requires periodic testing and inspection of the pump and its driver so diesel engine subsystems can perform their intended functions. Because periodic testing and inspections will be conducted to manage the effects of aging, the staff finds the applicant's AMR results acceptable.

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

3.3A.2.3.9 Fire Protection - Carbon Dioxide, Halon, and RCP Oil Collection Systems - Summary of Aging Management Review – LRA Table 3.3.2-12-IP2

The staff reviewed LRA Table 3.3.2-12-IP2, which summarizes the results of AMR evaluations for the fire protection - carbon dioxide, halon, and RCP oil collection systems component groups.

The LRA table referenced Note G for copper alloy flame arrestor and nozzle internally exposed to air-indoor, with no aging effect and no AMP given. The staff finds the applicant's results acceptable because other sections of the GALL Report give the same aging effect and AMP for a similar material/environment combination (e.g., GALL Report Table VII.J, Line Item VII.J-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.

3.3A.2.3.10 Fuel Oil System - Summary of Aging Management Review – LRA Table 3.3.2-13-IP2

The staff reviewed LRA Table 3.3.2-13-IP2, which summarizes the results of AMR evaluations for the fuel oil system component groups.

The LRA table referenced Note G for carbon steel tanks exposed to concrete (external) with an aging effect of loss of material which is managed by the Aboveground Steel Tanks Program. SER Section 3.0.3.2.1 documents the staff's evaluation of the Aboveground Steel Tanks Program. Steel components exposed to concrete are addressed in the GALL Report with no aging effect identified; therefore, the applicant is conservative in assuming an aging effect of loss of material. The staff finds that use of the Aboveground Steel Tanks Program to manage the loss of material for the carbon steel tank exposed to concrete is acceptable because periodic tank inspections are conducted to monitor for loss of material, and thickness measurements of locations that are inaccessible for external visual inspection, such as tank bottom surfaces are performed. Such inspections will ensure that loss of material does not occur.

The LRA table referenced Note G for carbon steel heat exchanger tubes exposed to air-indoor (external) with an aging effect of fouling which is managed by the Periodic Surveillance and Preventive Maintenance Program. The GALL Report prescribes an aging effect of loss of material for this material/environment combination which is addressed by another line item in Table 3.3.2-13-IP2. The aging effect of fouling is in addition to that prescribed by the GALL Report. The staff's evaluation of the Periodic Surveillance and Preventive Maintenance is documented in SER Section 3.0.3.3.7. The program will use visual or other NDE techniques to inspect the fuel oil cooler for the SBO/Appendix R diesel generator to manage fouling. Based on the above, the staff finds that because the aging effect fouling will be adequately managed by using the Periodic Surveillance and Preventive Maintenance Program, the applicant's AMR result is acceptable.

The LRA table referenced Note G for carbon steel heat exchanger tubes exposed to fuel oil (internal) with an aging effect of fouling managed by the Diesel Fuel Monitoring Program. The GALL Report prescribes an aging effect of loss of material for this material/environment combination which is addressed by another line item in Table 3.3.2-13-IP2. The aging effect of fouling is in addition to that prescribed by the GALL Report. The Diesel Fuel Monitoring Program is an existing program that entails sampling to ensure that adequate diesel fuel quality is maintained to prevent loss of material and fouling in fuel systems. The One-Time Inspection Program describes inspections planned to verify the effectiveness of the Diesel Fuel Monitoring Program. Based on the above, the staff finds that because the aging effect fouling will be adequately managed by using the Diesel Fuel Monitoring Program, the applicant's AMR result is acceptable.

The LRA table referenced Note G for stainless steel tanks exposed to outdoor air (external) with an aging effect of loss of material managed by the Periodic Surveillance and Preventive Maintenance Program. The GALL Report states that stainless steel components are subject to loss of material and SCC, which would not be induced in an air environment; therefore, the aging effect addressed in the LRA is consistent with the GALL Report. The AMP will use visual or other NDE techniques to inspect internal and external surfaces of the emergency fuel oil trailer transfer tank and associated valves for loss of material. Based on the above, the staff finds that because the aging effect loss of material will be adequately managed by using the Periodic Surveillance and Preventive Maintenance Program, the applicant's AMR result is acceptable.

The LRA table referenced Note G for stainless steel valve bodies exposed to outdoor air (external) with an aging effect of loss of material managed by the External Surface Monitoring Program and the Periodic Surveillance and Preventive Maintenance Program. The GALL Report states that stainless steel components are subject to loss of material and SCC, which would not be induced in an air environment; therefore, the aging effect addressed in the LRA is consistent with the GALL Report.. The Periodic Surveillance and Preventive Maintenance Program will use visual or other NDE techniques to inspect internal and external surfaces of the emergency fuel oil trailer transfer tank and associated valves for loss of material. On the basis of its review, the staff finds that, because these components will be inspected periodically, the aging effect for these component/environment combinations will be effectively managed by the External Surface Monitoring Program and the Periodic Surveillance and Preventive Maintenance Program.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not 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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3A.2.3.11 Emergency Diesel Generator System - Summary of Aging Management Review – LRA Table 3.3.2-14-IP2

The staff reviewed LRA Table 3.3.2-14-IP2, which summarizes the results of AMR evaluations for the emergency diesel generator system component groups.

The LRA table referenced Note F for titanium material used in heat exchanger tubes. Titanium heat exchanger tubes exposed to lube oil (external) have the aging effect of fouling and loss of material which will be managed by the Oil Analysis Program. The Oil Analysis Program is discussed in SER Section 3.0.3.2.12. Titanium components are not addressed in the GALL Report. However, titanium is a corrosion resistant material; therefore, the applicant is conservative in addressing the aging effects of concern for titanium in the Emergency Diesel Generator System. The Oil Analysis Program is an existing program that maintains oil systems free of contaminants (primarily water and particulates) thereby preserving an environment that is not conducive to loss of material, cracking, or fouling. Activities include sampling and analysis of lubricating oil for detrimental contaminants, water, and particulates. The One-Time Inspection Program will be used to verify the effectiveness of the Oil Analysis program. Based on the above, the staff finds that the aging effects of fouling and loss of material will be adequately managed by using the Oil Analysis Program.

The LRA table referenced Note F for titanium heat exchanger tubes exposed to raw water (internal) having aging effects of fouling and loss of material which will be managed using the Service Water Integrity Program. The staff's review of the Service Water Integrity Program is documented in SER Section 3.0.3.1.14. The program includes component inspections for erosion, corrosion, and biofouling to verify the heat transfer capability of safety related heat exchangers cooled by service water. Chemical treatment using biocides and sodium hypochlorite and periodic cleaning and flushing of infrequently used loops are methods used to control fouling within the heat exchangers and to manage loss of material in service water components. Based on the above, the staff finds that the aging effect of fouling will be adequately managed by using the Service Water Integrity Program. The staff notes that in LRA Table 3.3.2-2-IP2, the applicant uses Note F for the same material/environment combination but cites cracking as an additional aging effect. The staff determined that this appeared to be a discrepancy. This was identified as part of Open Item 3.3-1.

By letter dated January 27, 2009, the applicant stated that the reason for the difference in aging effects is because the titanium tubes in LRA Table 3.3.2-14-IP2 for the emergency diesel generator are ASTM SB-338 Grade 2 titanium. The applicant further explained that as specified in the EPRI Mechanical Tools, and the Metals Handbook, Ninth Edition, Volume 13, grades 1, 2, 7, 11, and 12 of titanium and its alloys are virtually immune to SCC except in a few specific environments (such as anhydrous methanol/halide solutions, red fuming nitric acid (HNO3), and liquid cadmium). The applicant determined that since these tubes are exposed to raw water, cracking was not identified as an aging effect requiring management in LRA Table 3.3.2-14-IP2 (diesel generator system). However, because the applicant did not identify the grade of titanium installed in the service water system, it conservatively identified cracking as an aging effect requiring management in LRA Table 3.3.2-2-IP2 (service water system). Because the applicant did identify the grade of titanium in the diesel generator system, and that grade is not susceptible to cracking when exposed to an internal environment of raw water, the staff finds the applicant's AMR results to be acceptable. Therefore, Open Item 3.3-1 is closed.

The LRA table referenced Note F for titanium heat exchanger tubes exposed to treated water (external) have the aging effect of fouling and loss of material which will be managed by the Water Chemistry Control – Closed Cooling Water Program. The staff's review of the Water Chemistry Control – Closed Cooling Water Program is documented in SER Section 3.0.3.2.16. The Water Chemistry Control – Closed Cooling Water Program is an existing program that includes preventive measures that manage loss of material, cracking, or fouling for components in closed cooling water systems including emergency diesel generator cooling. The One-Time Inspection Program for Water Chemistry utilizes inspections or non-destructive evaluations of representative samples to verify that the Water Chemistry Control – Closed Cooling Water Program has been effective at managing aging effects. Based on the above, the staff finds that the aging effects of fouling and loss of material will be adequately managed by using the Water Chemistry Control – Closed Cooling Water Program.

The LRA table reference Note F for titanium heat exchanger tubes exposed to treated water (external) are also subject to the aging effect of loss of material – wear which will be managed by the Service Water Integrity Program. The staff's evaluation of this program is documented in SER Section 3.0.3.1.14. The program includes component inspections for erosion, corrosion, and biofouling to verify the heat transfer capability of safety-related heat exchangers cooled by service water. Chemical treatment using biocides and sodium hypochlorite and periodic cleaning and flushing of infrequently used loops are methods used to control fouling within the heat exchangers and to manage loss of material in service water components. Based on the above, the staff finds that the aging effect of loss of material-wear will be adequately managed by using the Service Water Integrity Program.

The LRA table referenced Note G for stainless steel duct exposed to air-indoor (internal) having no aging effect and no aging management program required. This material/environment is similar to other material/environment combinations in the GALL Report (e.g., Table VII.J, Line Item J-15) for which there is no AERM or AMP. Therefore, the staff agrees that there is no aging effect and no AMP required for stainless steel duct exposed to air-indoor (internal). The staff finds the applicant's AMR results acceptable.

The LRA table referenced Note G for copper alloy >15 percent zinc heat exchanger tubes exposed to air-indoor (external) with an aging effect of fouling, and valve bodies exposed to treated water (internal) with an aging effect of loss of material, which are managed by the Periodic Surveillance and Preventive Maintenance Program. The staff's evaluation of this program is documented in SER Section 3.0.3.3.7. The Periodic Surveillance and Preventive Maintenance Program will use visual or other NDE techniques to inspect a representative sample of EDG air intake and aftercooler components to manage fouling and loss of material, and EDG cooling water makeup supply valves to manage loss of material. Based on the above, the staff finds that the aging effect of fouling will be adequately managed by using the Periodic Surveillance and Preventive Maintenance Program.

The LRA table also referenced Note G and plant-specific Note 305 for copper alloy >15 percent zinc valve body internally exposed to treated water with an aging effect of loss of material. Note 305 states that "[t]his treated water environment includes water that has been treated but is not maintained by a chemistry control program, such as water from the city water system. There is no environment in the GALL Report that will support a useful comparison for this line." The applicant proposes to use the Periodic Surveillance and Preventive Maintenance Program to manage loss of material for copper alloy in this treated water environment. SER Section 3.0.3.3.7 documents the staff's evaluation of this program. For the city water system, as described in the Periodic Surveillance and Preventive Maintenance Program, the applicant will use visual or other NDE techniques to inspect a representative sample of the internals of city water system components exposed to treated water to manage the aging effect. The staff finds that that visual or NDE techniques are adequate for detecting loss of material in piping systems exposed to treated water. According to the GALL Report (Table IX.C), "[c]opper-zinc alloys >15% zinc are susceptible to stress corrosion cracking, selective leaching (except for inhibited brass), and pitting and crevice corrosion." However, as explained in the Metals Handbook Desk Edition, copyright 1985, by the American Society for Metals, SCC most commonly occurs in brass that is exposed to ammonia or amines. In order for SCC to occur, both tensile stress and a specific chemical species have to be present at the same time. Removal of either the stress or the chemical can prevent cracking. Since ammonia is not added to the city water system, the staff finds that SCC is not an aging effect likely to occur in the city water system. Based on the above, the staff finds the applicant's AMR results acceptable.

The LRA table referenced Note H for stainless steel expansion joint and valve body, and carbon steel silencer and piping, all exposed to an internal environment of exhaust gas, with an aging effect of "cracking-fatigue," and the AMP as "TLAA – metal fatigue." Note H indicates that the aging effect is not identified in the GALL Report for the component/material/environment combination. The staff's evaluation of the metal fatigue TLAAs is documented in SER Section 4.3.2. During an audit, the staff questioned the applicant about these AMR results, to gain a better understanding of the conditions and how cracking would be managed (Audit Item 232). In its response, dated December 18, 2007, the applicant provided additional explanation of the conditions potentially leading to cracking and the consequences of a crack on performance of intended function. The staff reviewed this information and concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences. On this basis, the staff finds the applicant's AMR results to be acceptable for these combinations.

The LRA table referenced Note H for stainless steel piping, strainer, thermowell, tubing, and valve body exposed to an internal or external environment of lube oil with an aging effect of cracking, and the Oil Analysis Program as the AMP. The staff's evaluation of the Oil Analysis Program is documented in SER Section 3.0.3.2.12. The staff determined that the aging effect of cracking is an appropriate aging effect to manage for the above combination because contaminants in the oil such as water and chlorides can cause cracking of stainless steel. The Oil Analysis Program maintains oil systems free of contaminants (primarily water and particulates) to preserve an environment that is not conducive to loss of material, cracking, or fouling. Because the AMP manages cracking, the staff finds that the aging effect of cracking will be adequately managed during the period of extended operation.

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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3A.2.3.12 Security Generator System - Summary of Aging Management Review – LRA Table 3.3.2-15-IP2

The staff reviewed LRA Table 3.3.2-15-IP2, which summarizes the results of AMR evaluations for the security generator system component groups.

The LRA table referenced Note G for copper alloy >15 percent zinc heat exchanger tubes exposed to air-indoor (external) with an aging effect of fouling which can lead to a loss of material. The applicant proposed to manage this material/environment/aging effect combination with the Periodic Surveillance and Preventive Maintenance Program. The staff's evaluation of this program is documented in SER Section 3.0.3.3.7. This program will use visual or other NDE techniques to inspect the surface condition of the radiator tubes and fins to manage loss of material on external surfaces. On the basis of its review, the staff finds that, because these components will be inspected periodically, the aging effect for these component/environment combinations will be effectively managed by the Periodic Surveillance and Preventive Maintenance Program.

The LRA table referenced Note H for aluminum heat exchanger fins exposed to air-indoor (external) with the aging effect fouling which will be managed by the Periodic Surveillance and Preventive Maintenance Program. The staff's evaluation of this program is documented in SER Section 3.0.3.3.7. This program will use visual or other NDE techniques to inspect the surface condition of the radiator tubes and fins to manage loss of material on external surfaces. The GALL Report, Table VII.J, Line Item J-1 addresses aluminum piping components exposed to indoor air with no aging effect identified; therefore, the LRA is conservative relative to the GALL Report. On the basis of its review, the staff finds that, because these components will be inspected periodically, the aging effect for these component/environment combinations will be effectively managed by the Periodic Surveillance and Preventive Maintenance Program.

The LRA table referenced Note H for stainless steel flexible bellows and carbon steel piping, silencer, turbocharger housing, and valve body exposed to an internal environment of exhaust gas with an aging effect of "cracking-fatigue," and an AMP of Periodic Surveillance and Preventive Maintenance. Note H indicates that the aging effect is not identified in the GALL Report for the component/material/environment combination. The staff's evaluation of the Periodic Surveillance and Preventive Maintenance is documented in SER Section 3.0.3.3.7. During an audit, the staff questioned the applicant about these AMR results, to gain a better understanding of the conditions and how cracking would be managed (Audit Item 232). In its response, dated December 18, 2007, the applicant provided additional explanation of the conditions potentially leading to cracking and the consequences of a crack on performance of intended function. The staff reviewed this information and concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences. On this basis, the staff finds the applicant's AMR results to be acceptable for these combinations.

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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3A.2.3.13 SBO/Appendix R Diesel Generator System - Summary of Aging Management Review – LRA Table 3.3.2-16-IP2

The staff reviewed LRA Table 3.3.2-16-IP2, which summarizes the results of AMR evaluations for the SBO/Appendix R diesel generator system component groups.

By letter dated April 30, 2008, the applicant amended the LRA to reflect the installation of the IP2 SBO/Appendix R diesel generator. In the amendment, the applicant revised LRA Table 3.3.2-16-IP2 to reflect the changes to the AMRs as a result of the modification. The staff's review of the revised Table 3.3.2-16-IP2 is provided below.

The LRA table referenced Note F for plastic filter housings and piping exposed to air-indoor both internally and externally with no AERM or AMP. Organic materials such as plastic are not subject to aging effects if ambient air is <95°F as indicated in Table IX.D of the GALL Report. Therefore, the staff finds that applicant's AMR results acceptable for this material/environment combination.

The LRA table referenced Note G and plant-specific Note 305 for carbon steel heat exchanger bonnet and shell, and stainless steel heat exchanger tubes exposed to an internal environment of treated water. The aging effects listed for these material/environment combinations include loss of material, fouling (stainless steel only), and cracking (stainless steel only). Note 305 states "This treated water environment includes water that has been treated but is not maintained by a chemistry control program, such as water from the city water system. There is no environment in the GALL Report that will support a useful comparison for this line." The applicant credits the Periodic Surveillance and Preventive Maintenance Program to manage loss of material, fouling, and cracking for carbon steel and stainless steel in this environment. The staff finds the applicant's AMR results to be appropriate. For the city water system, as described in the Periodic Surveillance and Preventive Maintenance Program, the applicant will use visual or other NDE techniques to inspect a representative sample of the internals of city water system components exposed to treated water to manage the aging effect. The staff finds that that visual or NDE techniques are adequate for detecting loss of material, fouling, and cracking in piping systems exposed to treated water.

The LRA table referenced Note G for stainless steel heat exchanger tubes exposed to an external environment of air-indoor with an aging effect of fouling. The applicant proposed to manage this aging effect by the Periodic Surveillance and Preventive Maintenance Program. The staff's review of this program is documented in SER Section 3.0.3.3.7. The GALL Report identifies no aging effect for stainless steel heat exchanger tubes exposed to indoor air (e.g., GALL Report Table V.F, Item V.F-12); therefore, postulation of the aging effect identified in the LRA is conservative. The Periodic Surveillance and Preventive Maintenance Program will use visual or other NDE techniques to inspect the external surface of heat exchanger tubes and fins to manage fouling. On the basis of its review, the staff finds that, because these components will be inspected periodically, the aging effect for these component/environment combinations will be effectively managed by the Periodic Surveillance and Preventive Maintenance Program.

The LRA referenced Note H for carbon steel heat exchanger fins exposed to an external environment of air-indoor with an aging effect of fouling. The applicant proposed to manage this combination by the Periodic Surveillance and Preventive Maintenance Program, The staff's review of this program is documented in SER Section 3.0.3.3.7. The Periodic Surveillance and Preventive Maintenance Program will use visual or other NDE techniques to inspect the external surface of heat exchanger tubes and fins to manage fouling. On the basis of its review, the staff finds that, because these components will be inspected periodically, the aging effect for these component/environment combinations will be effectively managed by the Periodic Surveillance and Preventive Maintenance Program.

The LRA table referenced Note H for stainless steel heat exchanger tubes exposed to treated water >140°F (internal) with an aging effect of loss of material–wear which is managed by the Heat Exchanger Monitoring Program. The staff's review of this program is documented in SER Section 3.0.3.3.3. The GALL Report identifies cracking and SCC as aging effects for stainless steel heat exchanger components exposed to treated water >140°F (e.g., Table VII.E3, Item VII.E3-2). The Heat Exchanger Monitoring Program inspects heat exchangers for loss of material through visual or other non-destructive examination. Although the applicant does not cite cracking and SCC as the applicable aging effects requiring management, the Heat Exchanger Monitoring Program uses NDE methods, such as eddy current testing (ECT) or ultrasonic testing (UT), to determine loss of material due to wear and to detect cracking. On the basis of its review, the staff finds that, because these components will be inspected periodically, the aging effect for these component/environment combinations will be effectively managed by the Heat Exchanger Monitoring Program.

The LRA referenced Note H for stainless steel heat exchanger tubes exposed to lube oil (external) with an aging effect of cracking managed by the Oil Analysis Program. The staff's evaluation of this program is documented in SER Section 3.0.3.2.12. The staff determined that the aging effect of cracking is an appropriate aging effect to manage for the above combination because contaminates in the oil such as water and chlorides can cause cracking of stainless steel. The Oil Analysis Program maintains oil systems free of contaminants (primarily water and particulates) to preserve an environment that is not conducive to loss of material, cracking, or fouling. Because the AMP manages cracking, the staff finds that the aging effect of cracking will be adequately managed during the period of extended operation.

The LRA table referenced Note H for carbon steel piping and silencer exposed to an internal environment of exhaust gas with an aging effect "cracking-fatigue" and the AMP as "TLAA – metal fatigue." The staff's evaluation of the metal fatigue TLAAs is documented in SER Section 4.3.2. During an audit, the staff questioned the applicant about these AMR results, to gain a better understanding of the conditions and how cracking would be managed (Audit Item 232). In its response, dated December 18, 2007, the applicant provided additional explanation of the conditions potentially leading to cracking and the consequences of a crack on performance of intended function. The staff reviewed this information and concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences. On this basis, the staff finds the applicant's AMR results to be acceptable for these combinations.

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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3A.2.3.14 City Water System - Summary of Aging Management Review – LRA Table 3.3.2-17-IP2

The staff reviewed LRA Table 3.3.2-17-IP2, which summarizes the results of AMR evaluations for the city water system component groups.

The LRA table referenced Note G and plant-specific Note 305 for carbon steel piping, tank, and valve body, gray cast iron piping and valve body, copper alloy tubing, and copper alloy >15 percent zinc valve body exposed to an internal environment of treated water. The aging effect listed for these material/environment combinations is loss of material. Note 305 states "[t]his treated water environment includes water that has been treated but is not maintained by a chemistry control program, such as water from the city water system. There is no environment in the GALL Report that will support a useful comparison for this line." The applicant credits the Periodic Surveillance and Preventive Maintenance Program to manage loss of material for carbon steel, copper alloy, and gray cast iron in this treated water environment. SER Section 3.0.3.3.7 documents the staff's evaluation of this program. For the city water system, as described in the Periodic Surveillance and Preventive Maintenance Program, the applicant will use visual or other NDE techniques to inspect a representative sample of the internals of city water system components exposed to treated water to manage the aging effect. The staff finds that that visual or NDE techniques are adequate for detecting loss of material in piping systems exposed to treated water. According to the GALL Report (Table IX.C), "[c]opper-zinc alloys >15% zinc are susceptible to stress corrosion cracking, selective leaching (except for inhibited brass), and pitting and crevice corrosion." However, as explained in the Metals Handbook Desk Edition, copyright 1985, by the American Society for Metals, SCC most commonly occurs in brass that is exposed to ammonia or amines. In order for SCC to occur, both tensile stress and a specific chemical species have to be present at the same time. Removal of either the stress or the chemical can prevent cracking. Since ammonia is not added to the city water system, the staff finds that SCC is not an aging effect likely to occur in the city water system. Based on the above, the staff finds the applicant's AMR results acceptable.

The LRA table referenced Note G for carbon steel tanks exposed to concrete (external) with an aging effect of loss of material to be managed by the Aboveground Steel Tanks Program. According to the GALL Report Table IX.B, steel tanks with bottoms in a soil or concrete environment have general corrosion as the aging effect for the interface between soil or concrete and the bottom of the tank. Degradation of the tank bottoms in these aboveground steel tanks can be managed by the GALL AMP XI.M29 "Aboveground Steel Tanks." Because the applicant proposes to manage loss of material using its Aboveground Steel Tanks Program which is consistent with guidance in the GALL Report, the staff finds the applicant's AMR results to be acceptable.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging 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).

3.3A.2.3.15 Plant Drains - Summary of Aging Management Review – LRA Table 3.3.2-18-IP2

The staff reviewed LRA Table 3.3.2-18-IP2, which summarizes the results of AMR evaluations for the plant drains component groups.

The LRA referenced Note G for stainless steel bolting and piping exposed to an external environment of outdoor air, with the aging effect of loss of material. The applicant proposed to manage the aging of the bolting and the piping by the Bolting Integrity Program and the External Surfaces Monitoring Program, respectively. The staff's evaluation of these programs is documented in SER Sections 3.0.3.2.2 and 3.0.3.2.5, respectively. The GALL Report states that stainless steel components are subject to loss of material and SCC, which would not be induced by an air environment. The Bolting Integrity Program conducts inspections of bolting in accordance with the ASME Section XI, Tables IWB 2500-1, IWC 2500-1 and IWD 2500-1, using visual techniques to inspect for leakage, loss of material, cracking, and loss of preload/loss of prestress. The External Surfaces Monitoring Program uses periodic plant system inspections and walkdowns to monitor for material degradation and leakage. On the basis of its review, the staff finds that, because these components will be inspected periodically for loss of material, the aging effect for these component/environment combinations will be effectively managed by the respective programs.

In a letter dated June 30, 2009, the applicant added drain piping and float valve to LRA Table 3.3.2-18-IP2. These additional AMR line items reference Note F for plastic piping exposed to indoor air on the internal surface, and exposed to indoor air or soil on the external surface. The aging effect and AMP are listed as "none." No aging effect would be expected because there are no stressors for plastics for the named environments. Typical stressors are exposure to UV radiation, high temperatures, and oxidizing conditions. In addition, the staff notes that plastic piping is used extensively in gas distribution systems and is exposed to soil with no adverse effects caused by the soil, which poses a more aggressive environment than indoor air. The staff has not identified any age-related industry experience for plastic material in indoor air and soil environments. Therefore, the staff finds the applicant's AMR results to be appropriate.

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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3A.2.3.16 Auxiliary Steam System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-1-IP2

The staff reviewed LRA Table 3.3.2-19-1-IP2, which summarizes the results of AMR evaluations for the auxiliary steam system component groups.

The LRA table referenced Note G for flex joint, piping, tubing, valve body/stainless steel/ steam (internal)/cracking–fatigue/TLAA–metal fatigue. The table also referenced Note F for valve body/CASS/steam (internal)/cracking–fatigue/TLAA–metal fatigue. The staff's evaluation of the metal fatigue TLAAs is documented in SER Section 4.3.2. The staff questioned the applicant about these AMR results, to gain a better understanding of the conditions and how cracking would be managed (Audit Item 233). In its response, dated December 18, 2007, the applicant provided additional explanation of the conditions potentially leading to cracking and the consequences of a crack on performance of intended function. The staff reviewed this information and concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences.

The LRA table referenced Note G for copper alloy valve body exposed to an internal environment of steam and an aging effect of loss of material. The applicant proposed to manage loss of material for this material/environment combination using the Water Chemistry Control–Primary and Secondary Program. The staff's evaluation of this program is documented in SER Section 3.0.3.2.17. As stated in GALL Report Table IX.C, copper alloy is resistant to stress corrosion cracking, selective leaching and pitting and crevice corrosion. The Water Chemistry Control - Primary and Secondary Program includes periodic monitoring and control of known detrimental contaminants such as chlorides, fluorides, dissolved oxygen, and sulfate concentrations below the levels known to result in loss of material or cracking. The staff questioned the applicant about whether or not the One-Time Inspection is also credited to verify the effectiveness of the Water Chemistry Control - Primary and Secondary (Audit Item 72). In its response dated December 18, 2007, the applicant confirmed that the One-Time Inspection will be used to verify the effectiveness of the Water Chemistry Programs. On this basis, the staff finds the applicant's AMR results to be acceptable for these combinations.

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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3A.2.3.17 Chemical Feed System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-3-IP2

The staff reviewed LRA Table 3.3.2-19-3-IP2, which summarizes the results of AMR evaluations for the chemical feed system component groups.

The LRA table referenced Note G and plant-specific Note 318 for stainless steel components (e.g., piping, pump casing, valve body) exposed to an internal environment of treated water with an aging effect of loss of material. The applicant proposed to manage loss of material for this material/environment combination using the One-Time Inspection Program. Note 318 states "[t]his treated water environment includes chemical solutions used to control primary and secondary system water chemistry or as an additive for containment spray." The above material/environment combination is similar to other combinations in the GALL Report (e.g., Table VIII.B, Line Item B1-4 and Table VIII.G Line Item G-32) which recommend water chemistry control augmented by a one-time inspection to verify the effectiveness of the water chemistry., Because the water chemistry is controlled by plant procedures and will be verified by the One-Time Inspection Program, the staff finds the applicant's AMR result acceptable.

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

3.3A.2.3.18 Condensate System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-4-IP2

The staff reviewed LRA Table 3.3.2-19-4-IP2, which summarizes the results of AMR evaluations for the condensate system component groups.

The LRA table referenced Note H for stainless steel components (e.g., expansion joint, piping, valve body) with an internal environment of steam and an aging effect of cracking-fatigue. The applicant credits TLAA-metal fatigue as the means for managing aging. The staff's evaluation of the metal fatigue TLAAs is documented in SER Section 4.3.2. During an audit, the staff questioned the applicant about the TLAA for expansion joints (Audit Item 233). By letter dated December 18, 2007, the applicant revised the AMR table, on the basis that, by design, an expansion joint can accommodate displacement without significant stress. The applicant provided additional explanation of the conditions potentially leading to cracking and the consequences of a crack on performance of intended function. The staff reviewed this information and concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences. The staff finds the applicant's AMR results to be acceptable.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging 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).

3.3A.2.3.19 City Water System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-7-IP2

The staff reviewed LRA Table 3.3.2-19-7-IP2, which summarizes the results of AMR evaluations for the city water system component groups.

The LRA table referenced Note G and plant-specific Note 305 for carbon steel filter housing, piping, pump casing, strainer housing, and tank; copper alloy piping and tubing; copper alloy > 15 percent zinc valve body; and gray cast iron valve body all exposed to an internal environment of treated water. The aging effect listed for these material/environment combinations is loss of material. The applicant credits the Periodic Surveillance and Preventive Maintenance Program to manage loss of material for the above material/environment combinations. As documented in SER Section 3.3A.2.3.14, the staff determined that visual or NDE techniques are adequate for detecting loss of material in the city water system components exposed to treated water.

For stainless steel tubing and CASS valve body exposed to treated water, the applicant proposed the One-Time Inspection Program to managing the loss of material. The staff's evaluation of this program is documented in SER Section 3.0.3.1.9. This program also uses NDE techniques to monitor for loss of material. The staff verified that the One-Time Inspection Program includes monitoring of the internal surfaces of city water system stainless steel and CASS components containing treated water. Based on the above, the staff finds that the applicant's AMR results are acceptable.

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

3.3A.2.3.20 Emergency Diesel Generator System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-9-IP2

The staff reviewed LRA Table 3.3.2-19-9-IP2, which summarizes the results of AMR evaluations for the emergency diesel generator system component groups.

The LRA table referenced Note G and plant-specific Note 305 for stainless steel piping and valve body exposed to treated water. The applicant proposed the One-Time Inspection Program to managing the loss of material. The staff's evaluation of this program is documented in SER Section 3.0.3.1.9. This program uses NDE techniques to monitor for loss of material. The staff verified that the One-Time Inspection Program includes monitoring of the emergency diesel generator system stainless steel components containing treated water. Based on the above, the staff finds that the applicant's AMR results are acceptable.

The LRA table referenced Note H for stainless steel or carbon steel piping and valve body exposed to an internal environment of condensation with an aging effect of cracking-fatigue, and cites the AMP as TLAA-metal fatigue. The staff's evaluation of the metal fatigue TLAAs is documented in SER Section 4.3.2. The staff questioned the applicant about these AMR results, to gain a better understanding of the conditions and how cracking would be managed (Audit Item 233). In its response, dated December 18, 2007, the applicant provided additional explanation of the conditions potentially leading to cracking and the consequences of a crack on performance of intended function. The staff reviewed this information and concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences. On this basis, the staff finds the applicant's AMR results to be acceptable for these combinations.

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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3A.2.3.21 Fresh Water Cooling System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-13-IP2

The staff reviewed LRA Table 3.3.2-19-13-IP2, which summarizes the results of AMR evaluations for the fresh water cooling system component groups.

The LRA table referenced Note G and plant-specific Note 305 for carbon steel compressor housing, heat exchanger shell, piping, pump casing, tank, and valve body; copper alloy valve body; and copper alloy >15 percent zinc valve body all of which are exposed to an internal environment of treated water. The aging effect listed for these material/environment combinations is loss of material. The applicant credits the Periodic Surveillance and Preventive Maintenance Program to manage loss of material for the above material/environment combinations. As noted in earlier sections of this SER, the staff determined that visual or NDE techniques are adequate for detecting loss of material in water system components exposed to treated water.

For stainless steel piping and valve body exposed to treated water, the applicant proposed the One-Time Inspection Program to manage the loss of material. The staff's evaluation of this program is documented in SER Section 3.0.3.1.9. This program also uses NDE techniques to monitor for loss of material. The staff verified that the One-Time Inspection Program includes monitoring of the internal surfaces of fresh water cooling system stainless steel components containing treated water. Based on the above, the staff finds that the applicant's AMR results are acceptable.

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

3.3A.2.3.22 House Service Boiler System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-16-IP2

The staff reviewed LRA Table 3.3.2-19-16-IP2, which summarizes the results of AMR evaluations for the house service boiler system component groups.

The LRA table referenced Note G for copper alloy >15 percent zinc valve body exposed to an internal environment of steam with an aging effect of loss of material. The applicant proposed to manage loss of material for this material/environment combination using the Water Chemistry Control – Auxiliary Systems Program. The staff's evaluation of this program is documented in SER Section 3.0.3.3.8. This program manages loss of material in copper alloy components by monitoring the pH and dissolved oxygen content in the treated water. Such monitoring is effective in reducing loss of material. As stated in the LRA, the applicant will use the One-Time Inspection Program for water chemistry which utilizes inspections or NDE of representative samples to verify that the Water Chemistry Control – Auxiliary Systems Program has been effective at managing aging effects. Because the aforementioned AMPs will manage loss of material, the staff finds the applicant's AMR results acceptable.

The LRA table referenced Note G for stainless steel tubing and valve body exposed to an internal environment of steam with an aging effect of cracking–fatigue. The applicant listed TLAA–metal fatigue as the means to manage cracking due to fatigue. The staff's evaluation of the metal fatigue TLAAs is documented in SER Section 4.3.2. During an audit, the staff questioned the applicant about the TLAA for expansion joints (Audit Item 233). In its response, dated December 18, 2007, the applicant provided its explanation of the conditions potentially leading to cracking and the consequences of a crack on performance of intended function. The staff reviewed this information and concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences. On this basis, the staff finds the applicant's AMR results to be acceptable for these combinations.

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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3A.2.3.23 Heating, Ventilation and Air Conditioning System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-17-IP2

The staff reviewed LRA Table 3.3.2-19-17-IP2, which summarizes the results of AMR evaluations for the HVAC system component groups.

The LRA table referenced Note G for stainless steel valve body exposed to an internal environment of steam with an aging effect of cracking-fatigue. As explained in the above section, the staff concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences. On this basis, the staff finds the applicant's AMR results to be acceptable for these combinations.

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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3A.2.3.24 Instrument Air System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-18-IP2

The staff reviewed LRA Table 3.3.2-19-18-IP2, which summarizes the results of AMR evaluations for the instrument air system component groups.

The LRA table referenced Note G for copper alloy valve body exposed to an internal environment of treated air. The applicant stated that there are no aging effects and no AMP is needed. A similar material/environment/aging effect/AMP combination exists in GALL Report Table VII.J line J-3; therefore, the staff finds the applicant's AMR result acceptable.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL

Report.

3.3A.2.3.25 Main Steam System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-23-IP2

The staff reviewed LRA Table 3.3.2-19-23-IP2, which summarizes the results of AMR evaluations for the main steam system component groups.

The LRA table referenced Note H for stainless steel components (e.g., expansion joint, piping, valve body) with an internal environment of steam and an aging effect of cracking-fatigue. The applicant credits TLAA-metal fatigue as the means for managing aging. The staff's evaluation of the metal fatigue TLAAs is documented in SER Section 4.3.2. During an audit, the staff questioned the applicant about the TLAA for expansion joints (Audit Item 233). By letter dated December 18, 2007, the applicant revised the AMR table, on the basis that, by design, an expansion joint can accommodate displacement without significant stress. The applicant provided additional explanation of the conditions potentially leading to cracking and the consequences of a crack on performance of an intended function. The staff reviewed this information and concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences. The staff finds the applicant's AMR results to be acceptable.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging 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).

3.3A.2.3.26 Miscellaneous System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-24-IP2

The staff reviewed LRA Table 3.3.2-19-24-IP2, which summarizes the results of AMR evaluations for the miscellaneous system component groups.

The LRA table referenced Note G and plant-specific Note 305 for carbon steel piping and valve body exposed to an internal environment of treated water with an aging effect of loss of material. The applicant credits the Periodic Surveillance and Preventive Maintenance Program to manage loss of material for the above material/environment combination. As noted in earlier sections of this SER, the staff determined that visual or NDE techniques are adequate for detecting loss of material in water system components exposed to treated water. Therefore, the staff finds the applicant's AMR result acceptable.

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

3.3A.2.3.27 Post-Accident Containment Air Sampling System, Nonsafety-Related Components Potentially Affecting Safety Functions – Summary of Aging Management Review – LRA Table 3.3.2-19-26-IP2

The staff reviewed LRA Table 3.3.2-19-26-IP2, which summarizes the results of AMR evaluations for the post-accident containment air vent system component groups.

The LRA referenced Note G for stainless steel gas analyzer, piping, tank, and valve body with an internal environment of air-indoor and no aging effect or AMP cited. A similar material/environment/aging effect/AMP combination exists in GALL Report Table VIII.I Line Item I-10. Because no aging effects are expected for this material/environment combination, the staff finds the applicant's AMR result acceptable.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report.

3.3A.2.3.28 Post-Accident Containment Air Vent System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-27-IP2

The staff reviewed LRA Table 3.3.2-19-27-IP2, which summarizes the results of AMR evaluations for the post-accident containment air vent system component groups.

The LRA table referenced Note G for stainless steel filter housing, piping, and valve body exposed to an internal environment of air-indoor. The aging effect and AMP are listed as "none." The GALL Report contains similar line items for this material/environment combination for which the aging effect and AMP are listed as "none" (e.g., Table VII.J, Line Items VII.J-15, VII.J-18, VII.J-20). Therefore, the staff finds the applicant's AMR results acceptable.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report.

3.3A.2.3.29 Primary Sampling System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-28-IP2

The staff reviewed LRA Table 3.3.2-19-28-IP2, which summarizes the results of AMR evaluations for the primary sampling system component groups.

The LRA table referenced Note F for plastic piping and valve body exposed to an internal environment of treated water and an external environment of air-indoor. The aging effect and AMP are listed as "none." No aging effect would be expected because there are no stressors for plastics for the named environments. Typical stressors are exposure to UV radiation, high temperatures, and oxidizing conditions. Therefore, the staff finds the applicant's AMR results to be appropriate.

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.

3.3A.2.3.30 Reactor Coolant System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-30-IP2

The staff reviewed LRA Table 3.3.2-19-30-IP2, which summarizes the results of AMR evaluations for the reactor coolant system component groups.

The LRA table referenced Note F and plant-specific Note 313 for carbon steel tank exposed to an internal environment of treated borated water. The applicant listed the aging effect as loss of material and proposed to manage this aging effect with the Periodic Surveillance and Preventive Maintenance Program. The staff's review of this program is documented in SER Section 3.0.3.3.7. Note 313 states "[t]he tank is steel with a corrosion-resistant coating on the wetted surfaces (AMERCOAT 55 System)." The use of the Periodic Surveillance and Preventive Maintenance Program for the material/environment combination is appropriate because the tank will be periodically inspected using visual inspection or other NDE methods to detect loss of material. Therefore, the staff finds the applicant's AMR result acceptable.

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

3.3A.2.3.31 Boiler Blowdown System, Nonsafety-Related Components Potentially Affecting Safety Functions – Summary of Aging Management Review – LRA Table 3.3.2-19-34-IP2

The staff reviewed LRA Table 3.3.2-19-34-IP2, which summarizes the results of AMR evaluations for the boiler blowdown system component groups.

The LRA table referenced Note I, and plant specific Note 310, which states "[t]hese components remain at high temperature during normal operation which precludes moisture condensation and the resulting corrosion." The components referenced are carbon steel bolting, piping, tanks, and valve bodies exposed to an external environment of indoor air with no aging effect or AMP. A similar material/environment/aging effect/AMP combination exists in GALL Report Table VII.J Line Item J-20. The environment in this GALL Report line item is controlled indoor air which means that the air is controlled for humidity. The applicant stated that the components remain at high temperatures which results in low humidity. Because these two environments are similar, the staff finds the applicant's AMR result acceptable.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report.

3.3A.2.3.32 Secondary Sampling System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-38-IP2

The staff reviewed LRA Table 3.3.2-19-38-IP2, which summarizes the results of AMR evaluations for the secondary sampling system component groups.

The LRA table referenced Note G for stainless steel piping; valve body exposed to an internal environment of steam. The aging effect listed was cracking–fatigue, and the management method was given as TLAA–metal fatigue. The staff's evaluation of the metal fatigue TLAAs is documented in SER Section 4.3.2. The staff questioned the applicant about these AMR results, to gain a better understanding of the conditions and how cracking would be managed (Audit Item 233). In its response, dated December 18, 2007, the applicant provided additional explanation of the conditions potentially leading to cracking and the consequences of a crack on performance of intended function. The staff reviewed this information and concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences. On this basis, the staff finds the applicant's AMR results to be acceptable for these combinations.

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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3A.2.3.33 Service Water System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-39-IP2

The staff reviewed LRA Table 3.3.2-19-39-IP2, which summarizes the results of AMR evaluations for the service water system component groups.

The LRA table referenced Note F for plastic piping and valve bodies exposed to external condensation and raw water internally. No aging effect or AMP was identified. No aging effect would be expected because there are no stressors for plastics exposed externally to condensation or raw water internally. Typical stressors are exposure to UV radiation, exposure to high temperatures, and exposure to oxidizing conditions. Therefore, the staff finds the applicant's AMR results to be appropriate.

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.

3.3A.2.3.34 Main Turbine System, Nonsafety-Related Components Potentially Affecting Safety Functions – Summary of Aging Management Review – LRA Table 3.3.2-19-41-IP2

The staff reviewed LRA Table 3.3.2-19-41-IP2, which summarizes the results of AMR evaluations for the water main turbine system component groups.

The LRA referenced Note I, and plant specific Note 310, which states "[t]hese components remain at high temperature during normal operation which precludes moisture condensation and the resulting corrosion." The component referenced is a carbon steel turbine housing externally exposed to indoor air with no aging effect or aging management program. A similar material/environment/aging effect/AMP combination exists in GALL Report Table VII.J line Item J-20. The environment in this GALL Report line item is controlled indoor air which means that the air is controlled for humidity. The applicant stated that the components remain at high temperatures which results in low humidity. Because these two environments are similar, the staff finds the applicant's AMR result acceptable.

3.3A.2.3.35 Water Treatment Plant System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-43-IP2

The staff reviewed LRA Table 3.3.2-19-43-IP2, which summarizes the results of AMR evaluations for the water treatment plant system component groups.

The LRA table referenced Note F for plastic piping exposed to air-indoor externally and treated water internally. No aging effect or AMP is identified. No aging effect would be expected because there are no stressors for plastics exposed externally to air-indoor or treated water internally. Typical stressors are exposure to UV radiation, exposure to high temperatures, and exposure to oxidizing conditions. Therefore, the staff finds the applicant's AMR results to be appropriate.

The LRA table referenced Note G and plant-specific Note 305, which states "This treated water environment includes water that has been treated but is not maintained by a chemistry control program, such as water from the city water system. There is no environment in the GALL Report that will support a useful comparison for this line." The applicant credits the Periodic Surveillance and Preventive Maintenance AMP to manage loss of material for carbon steel and gray cast iron in this treated water environment. The staff's evaluation of this program is documented in SER Section 3.0.3.3.7. As noted in earlier sections of this SER, the staff determined that visual or NDE techniques are adequate for detecting loss of material in water system components exposed to treated water.

For stainless steel piping and valve body exposed to treated water, the applicant proposed the One-Time Inspection Program to manage the loss of material. The staff's evaluation of this program is documented in SER Section 3.0.3.1.9. This program also uses NDE techniques to monitor for loss of material. The staff verified that the One-Time Inspection Program includes monitoring of the internal surfaces of the water treatment plant system stainless steel components containing treated water. Based on the above, the staff finds that the applicant's AMR results are acceptable.

By letter dated January 4, 2008, the applicant revised its LRA to include an AMR line item for carbon steel tank with an external environment of concrete, an aging effect of "loss of material," and Note G. The applicant credits the Aboveground Steel Tanks Program to manage the loss of material for this carbon steel tank exposed to an external environment of concrete. SER Section 3.0.3.2.1 documents the staff's evaluation of the Aboveground Steel Tanks Program. The staff finds that use of the Aboveground Steel Tanks Program to manage the loss of material for the carbon steel tank exposed to concrete is acceptable because periodic tank inspections are conducted to monitor for loss of material, and thickness measurements of locations that are inaccessible for external visual inspection, such as tank bottom surfaces are performed. Such inspections will ensure that loss of material does not occur.

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

3.3A.2.3.36 Chlorination System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-44-IP2

In response to RAI 2.1-1, part (b), dated February 13, 2008, the applicant revised the LRA to add the chlorination system to the scope of license renewal. In addition, the applicant added LRA Table 3.3.2-19-44-IP2, which summarizes the results of AMR evaluations for the chlorination system component groups. The staff reviewed LRA Table 3.3.2-19-44-IP2.

The LRA table referenced Note G and plant specific Not 305 for carbon steel piping and valve bodies exposed to treated water (internal) with an aging effect of loss of material to be managed by the Periodic Surveillance and Preventive Maintenance Program. SER Section 3.0.3.3.7 documents the staff's evaluation of the Periodic Surveillance and Preventive Maintenance Program. As noted in earlier sections of this SER, the staff determined that visual or NDE techniques are adequate for detecting loss of material in water system components exposed to treated water. Therefore, the staff finds the applicant's AMR result acceptable.

3.3B.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.3.2-1-IP3 through 3.3.2-18-IP3 and 3.3.2-19-1-IP3 through 3.3.2-19-62-IP3, 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-IP3 through 3.3.2-18-IP3 and 3.3.2-19-1-IP3 through 3.3.2-19-62-IP3, the applicant indicated, via notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information about how it will manage the aging effects. Specifically, Note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation. The staff's evaluation is documented in the following sections.

3.3B.2.3.1 Service Water System - Summary of Aging Management Review – LRA Table 3.3.2-2-IP3

The staff reviewed LRA Table 3.3.2-2-IP3, which summarizes the results of AMR evaluations for the service water system component groups.

The LRA referenced Note G for glass indicator exposed to condensation (external) with no aging effect or aging management program. In Table IX.D of the GALL Report, condensation on the surfaces of systems with temperatures below the dew point is considered raw water. A similar line item exists in GALL Report Table VII.J, Line Item J-11 for the material/environment combination of glass/raw water. Because these combinations are similar, and the GALL Report does not identify an aging effect or AMP for the combination, the staff finds the applicant's AMR result acceptable.

The LRA table referenced Note G for nickel alloy valve bodies exposed to condensation (external) with an aging effect of loss of material managed by the External Surfaces Monitoring Program. As documented in SER Section 3.3A.2.3.1, the staff finds that use of the External Surfaces Monitoring Program to conduct periodic plant system inspections and walkdowns for evidence of material loss of the external surfaces of the valve bodies is acceptable.

The LRA table referenced Note H for heat exchanger (tubes) constructed from copper alloy >15 percent zinc (inhibited) exposed to treated water (external) subject to loss of material-wear which will be managed by the Heat Exchanger Monitoring AMP. The staff reviewed the Heat Exchanger Monitoring Program in SER Section 3.0.3.3.3. The aging effect identified in the GALL Report for this material/environment is loss of material, which is addressed by another line item in LRA Table 3.3.2-2-IP3. The aging effect identified in the LRA is in addition to that prescribed by the GALL Report. The Heat Exchanger Monitoring Program uses visual or other NDE techniques to inspect heat exchangers for loss of material. The staff's review of the referenced AMP has verified that the aging effect identified will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, and is therefore acceptable.

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

3.3B.2.3.2 Component Cooling Water System - Summary of Aging Management Review – LRA Table 3.3.2-3-IP3

The staff reviewed LRA Table 3.3.2-3-IP3, which summarizes the results of AMR evaluations for the component cooling water system component groups.

Three (3) groups reference Note H for copper alloy >15 percent zinc (inhibited) and stainless steal heat exchanger (tubes) exposed to treated water with the aging effect of loss of material-wear with the aging managed using the Heat Exchanger Monitoring Program and the Service Water Integrity Program. The staff's review of the Heat Exchanger Monitoring Program is documented in SER Section 3.0.3.3.3, and the Service Water Integrity Program is documented in SER Section 3.0.3.1.14. As stated in SER Section 3.3A.2.3.2, the staff finds that because these components will be inspected periodically, the aging effect for these material/environment combinations will be effectively managed by the Heat Exchanger Monitoring Program and the Service Water Integrity Program.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not 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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3B.2.3.3 Chemical and Volume Control System - Summary of Aging Management Review – LRA Table 3.3.2-6-IP3

The staff reviewed LRA Table 3.3.2-6-IP3, which summarizes the results of AMR evaluations for the chemical and volume control system component groups.

The LRA table referenced Note H for heat exchanger (tubes) constructed from copper alloy externally exposed to lube oil and stainless steel externally exposed to treated water, with an aging effect of loss of material–wear managed by the Heat Exchanger Monitoring AMP. The aging effect identified in the LRA is in addition to that prescribed by the GALL Report. The staff's evaluation of the Heat Exchanger Monitoring Program is documented in SER Section 3.0.3.3.3. This program uses visual inspections or other NDE techniques of heat exchangers for loss of material. Because the heat exchanger tubes will be periodically inspected for loss of material, the staff finds the applicant's AMR results acceptable.

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

3.3B.2.3.4 Primary Makeup Water System - Summary of Aging Management Review – LRA Table 3.3.2-7-IP3

The staff reviewed LRA Table 3.3.2-7-IP3, which summarizes the results of AMR evaluations for the primary makeup water system component groups.

The LRA Table referenced Note G for stainless steel bolting externally exposed to outdoor air with the aging effect of loss of material, and the Bolting Integrity Program listed as the AMP. The staff's review of the Bolting Integrity Program is documented in SER Section 3.0.3.2.2. The program periodically inspects closure bolting for signs of leakage that may be due to crack initiation, loss of preload, or loss of material due to corrosion. The program also includes preventive measures to preclude or minimize loss of preload and cracking. The applicant uses plant procedures that address material and lubricant selection, design standards, and good bolting maintenance practices consistent with EPRI guidance. By controlling the material (i.e., the maximum yield strength), the applicant stated that it has not experienced SCC of pressure boundary bolting. On the basis of its review, the staff finds that, because these components will be inspected periodically, the aging effect of loss of material for stainless steel bolting exposed to outdoor will be effectively managed by the Bolting Integrity Program.

The LRA table referenced Note G for stainless steel heat exchanger tubes internally exposed to steam with the aging effects of cracking and loss of material, and the Water Chemistry Control-Primary and Secondary listed as the AMP. The staff's review of the Water Chemistry Control-Primary and Secondary is documented in SER Section 3.0.3.2.17. This program manages aging effects caused by corrosion and cracking mechanisms. The program monitors and controls reactor water chemistry based on EPRI TR-105714, Revision 5, "Pressurized Water Reactor Primary Water Chemistry Guidelines," and TR-102134, Revision 6, "Pressurized Water Reactor Secondary Chemistry Guidelines." On the basis of its review, the staff finds that, because these components will be inspected periodically, the aging effect of loss of material for stainless steel heat exchanger tubes exposed to steam (internal) will be effectively managed by the Water Chemistry Control-Primary and Secondary.

The LRA table also referenced Note G for stainless steel tank and stainless steel valve bodies externally exposed to outdoor air with the aging effect of loss of material managed by the External Surfaces Monitoring Program. As stated in SER Section 3.3A.2.3.4, an environment of uncontrolled air might result in condensation, therefore, loss of material is an appropriate aging effect to consider. The External Surfaces Monitoring Program inspects external surfaces of components subject to aging management review for loss of material. The staff's review of the referenced AMP is documented in SER Section 3.0.3.2.5, and has verified that loss of material will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation and is therefore acceptable.

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

3.3B.2.3.5 Heating, Ventilation and Air Conditioning Systems - Summary of Aging Management Review – LRA Table 3.3.2-8-IP3

The staff reviewed LRA Table 3.3.2-8-IP3, which summarizes the results of AMR evaluations for the HVAC systems component groups.

The LRA referenced Note G for aluminum damper and fan housings externally exposed to outdoor air, with an aging effect of loss of material, and the External Surfaces Monitoring Program listed as the AMP. As stated in SER Section 3.3A.2.3.4, an environment of uncontrolled air might result in condensation, therefore, loss of material is an appropriate aging effect to consider. As stated in SER Section 3.3A.2.3.5, because the applicant will perform periodic inspections of the housings to monitor for loss of material, the staff finds the applicant's AMR results acceptable.

The LRA table also referenced Note G for copper alloy tubing, and stainless steel ducts, tubing, and valve bodies internally exposed to air-indoor. The aging effect and AMP listed for these material/environment combinations were listed as "none." As stated in SER Section 3.3A.2.3.5, because these material/environment combinations are similar to combinations in the GALL Report (e.g., Table VII.J, Line Items J-3 and J-18), the staff finds the applicant's AMR results acceptable.

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

3.3B.2.3.6 Containment Cooling and Filtration System - Summary of Aging Management Review – LRA Table 3.3.2-9-IP3

The staff reviewed LRA Table 3.3.2-9-IP3, which summarizes the results of AMR evaluations for the containment cooling and filtration system component groups.

The LRA table referenced Note G for stainless steel heat exchanger tubes externally exposed to condensation with an aging effect of fouling, and the Service Water Integrity Program listed as the AMP. The staff's review of the Service Water Integrity Program is documented in SER Section 3.0.3.1.14. On the basis of its review, the staff finds that, because the stainless steel heat exchanger tubes exposed to condensation (external) will be inspected periodically, the aging effect for this component/environment combination will be effectively managed by the Service Water Integrity Program.

The LRA table referenced Note G for stainless steel moisture separators and copper alloy tubing externally exposed to air-indoor. The aging effect and AMP listed for these material/environment combinations are "none." These material/environment combinations are similar to combinations in the GALL Report (e.g., Table VII.J, Line Items J-3 and J-15), therefore, the staff finds the applicant's AMR results acceptable.

The LRA table also referenced Note H for copper alloy heat exchanger fins exposed to condensation (external) having the aging effect of fouling which is managed by the Service Water Integrity Program, and stainless steel heat exchanger tubes exposed to condensation (external) with the aging effect of loss of material-wear which is managed by the Periodic Surveillance and Preventive Maintenance Program. The staff's evaluation of these programs is documented in SER Sections 3.0.3.1.14 and 3.0.3.3.7, respectively. The staff finds the use of the Service Water Integrity Program to manage the effects of fouling acceptable because the program will use inspections to monitor for fouling and will chemically treat the heat exchanger fins to prevent fouling. As noted in earlier sections of this SER, the staff determined that visual or NDE techniques are adequate for detecting loss of material in water system components exposed to water or like environments (e.g., condensation). Therefore, the staff finds the applicant's AMR results acceptable.

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

3.3B.2.3.7 Control Room HVAC System - Summary of Aging Management Review – LRA Table 3.3.2-10-IP3

The staff reviewed LRA Table 3.3.2-10-IP3, which summarizes the results of AMR evaluations for the control room HVAC system component groups.

The LRA table referenced Note G for stainless steel bolting exposed to outdoor air (external) having the aging effect of loss of material which is managed by the Bolting Integrity Program and by the External Surfaces Monitoring Program. The staff's review of the Bolting Integrity Program is documented in SER Section 3.0.3.2.2 and the External Surfaces Monitoring Program is documented in Section 3.0.3.2.5. The Bolting Integrity Program is recommended in Table 3, Item 43, of the GALL Report to manage the loss of material due to general, pitting, and crevice corrosion in steel bolting exposed to outdoor air (external). The External Surfaces Monitoring Program inspects the external surfaces of components subject to an aging management review for loss of material. Based on the above, the staff finds that because the aging effect of the loss of material in these components will be adequately managed by using the Bolting Integrity Program, the applicant's AMR results are acceptable.

The LRA table referenced Note G for stainless steel filter housing internally exposed to air-indoor with an aging effect and AMP listed as "none." This material/environment combination is similar to combinations in the GALL Report (e.g., Table VII.J, Line Items J-15 and J-18), whereby the aging effect and AMP are given as "none"; therefore, the staff finds the applicant's AMR results acceptable.

The LRA table also referenced Note G for copper alloy heat exchanger tubes exposed to outdoor air (external) having the aging effect of fouling and loss of material which is managed by the Periodic Surveillance and Preventive Maintenance Program. As stated in SER Section 3.3A.2.3.7, use of the Periodic Surveillance and Preventive Maintenance program using visual inspections or other NDEs is adequate to manage loss of material and fouling for the above component/material/environment. Therefore, the staff finds the applicant's AMR results acceptable.

The LRA table referenced Note G for copper alloy piping, tubing and valve bodies exposed to outdoor air (external) with an aging effect of loss of material which is managed by the External Surfaces Monitoring Program. The GALL Report identifies an aging effect of loss of material for copper components exposed to condensation which is a conservative approximation of outdoor air. As noted above, the External Surfaces Monitoring Program uses periodic inspections to monitor for loss of material on external surfaces. Therefore, the staff finds the applicant's AMR results acceptable because the external surfaces will be periodically inspected.

The LRA table referenced Note G for aluminum valve bodies are exposed to treated air (internal) which have no aging effect and no AMP is required This material/environment is similar to other material/environment combinations in the GALL Report (e.g., Table VII.J, Line Item J-1). Therefore, the staff agrees that there is no aging effect and no AMP required for aluminum valve bodies exposed to treated air (internal). The staff finds the applicant's AMR result acceptable.

The LRA table referenced Note G for aluminum heat exchanger fins externally exposed to outdoor air with an aging effect of fouling. The applicant proposed to manage this aging effect for this material/environment combination using the Periodic Surveillance and Preventive Maintenance Program. As stated in SER Section 3.3A.2.3.7, the Periodic Surveillance and Preventive Maintenance Program will visually inspect a representative sample of control room HVAC air cooled condensers and evaporators to manage loss of material and fouling. Based on the above the staff finds that the aging effects will be adequately managed and therefore is acceptable.

The LRA table referenced Note H for aluminum heat exchanger fins exposed to condensation (external) with the aging effect of fouling which is managed by the Periodic Surveillance and Preventive Maintenance Program. As stated above, the staff finds that use of the Periodic Surveillance and Preventive Maintenance program to visually inspect a representative sample of control room HVAC air cooled condensers and evaporators to manage loss of material and fouling is acceptable.

The LRA table referenced Note I and plant-specific Note 306, which states “Changes of material properties and cracking in elastomers are results of exposure to ultra-violet light or elevated temperatures (> 95°F). The interior surfaces of these components are not exposed to ultra-violet light and are part of the air intake that is not exposed to elevated temperatures.” The combination is duct flexible connection/elastomer/air–indoor (internal)/none/none. The staff finds that the applicant’s AMR result is appropriate because the elastomer flexible duct connections are not exposed to ultra-violet light or elevated temperatures.

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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3B.2.3.8 Fire Protection - Water System - Summary of Aging Management Review – LRA Table 3.3.2-11-IP3

The staff reviewed LRA Table 3.3.2-11-IP3, which summarizes the results of AMR evaluations for the fire protection - water system component groups.

The LRA table referenced Note G for stainless steel bolting exposed to outdoor air (external) with the aging effect of loss of material which is managed by the Bolting Integrity Program which is reviewed in SER Section 3.0.3.2.2. The Bolting Integrity Program is recommended in Table 3, Item 43, of the GALL Report to manage the loss of material due to general, pitting, and crevice corrosion in steel bolting exposed to outdoor air (external). Based on the above, the staff finds that the aging effect of the loss of material in these components will be adequately managed by using the Bolting Integrity Program.

The LRA table referenced Note G for copper alloy >15 percent zinc nozzle exposed to air-indoor (internal) which has no aging effect and no aging management program is required. As stated in SER Section 3.3A.2.3.8, this material/environment is similar to other material/environment combinations in the GALL Report (e.g., Table VII.J, Line Item J-3). Therefore, the staff finds the applicant’s AMR results acceptable.

The LRA table referenced Note G for carbon steel tank exposed to concrete (external) with the aging effect of loss of material which is managed by the Aboveground Steel Tank Program. SER Section 3.0.3.2.1 documents the staff’s evaluation of the Aboveground Steel Tanks Program. Steel components exposed to concrete are addressed in the GALL Report with no aging effect identified; therefore, the LRA is conservative in assuming an aging effect of loss of material. The staff finds that use of the Aboveground Steel Tanks Program to manage the loss of material for the carbon steel tank exposed to concrete is acceptable because periodic tank inspections are conducted to monitor for loss of material, and thickness measurements of locations that are inaccessible for external visual inspection, such as tank bottom surfaces are performed. Such inspections will ensure that loss of material does not occur.

The LRA table referenced Note H carbon steel expansion joints, piping, and silencer exposed to exhaust gas (internal) with the aging effect of cracking-fatigue which is managed by the Fire Protection Program. The GALL Report identifies an aging effect for this material/environment combination of loss of material which is addressed by another line item in Table 3.3.2-11-IP3. The aging effect identified in the LRA is in addition to that prescribed by the GALL Report. The staff's review of the Fire Protection Program is documented in SER Section 3.0.3.2.7. The diesel-driven fire pump inspection requires periodic testing and inspection of the pump and its driver so diesel engine subsystems can perform their intended functions. Because periodic testing and inspections will be conducted to manage the effects of aging, the staff finds the applicant's AMR results acceptable.

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

3.3B.2.3.9 Fire Protection - Carbon Dioxide, Halon, and RCP Oil Collection Systems - Summary of Aging Management Review – LRA Table 3.3.2-12-IP3

The staff reviewed LRA Table 3.3.2-12-IP3, which summarizes the results of AMR evaluations for the fire protection - carbon dioxide, halon, and RCP oil collection systems component groups.

The LRA table referenced Note G for copper alloy filter and flame arrestor internally exposed to indoor air, with no aging effect and no AMP given. The staff finds the applicant's results acceptable because other sections of the GALL Report give the same aging effect and AMP for a similar material/environment combination (e.g., GALL Report Table VII.J, Line Item VII.J-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.

3.3B.2.3.10 Emergency Diesel Generator System - Summary of Aging Management Review – LRA Table 3.3.2-14-IP3

The staff reviewed LRA Table 3.3.2-14-IP3, which summarizes the results of AMR evaluations for the emergency diesel generator system component groups.

The LRA table referenced Note G for stainless steel duct exposed to air-indoor (internal) having no aging effect and no aging management program required. Based on precedence from prior license renewal reviews, the staff agrees that there is no aging effect and no AMP is required.

The LRA table referenced Note G for copper alloy >15 percent zinc heat exchanger tubes exposed to air-indoor (external) with an aging effect of fouling, and valve bodies exposed to treated water (internal) with an aging effect of loss of material, which are managed by the Periodic Surveillance and Preventive Maintenance Program. The staff's evaluation of this program is documented in SER Section 3.0.3.3.7. As documented in SER Section 3.3A.2.3.11, the staff finds that because the aging effect of fouling will be adequately managed by using the Periodic Surveillance and Preventive Maintenance Program, the applicant's AMR results are acceptable.

The LRA table also referenced Note G and plant-specific Note 305 for copper alloy >15 percent zinc valve body internally exposed to treated water with an aging effect of loss of material. Note 305 states that "[t]his treated water environment includes water that has been treated but is not maintained by a chemistry control program, such as water from the city water system. There is no environment in the GALL Report that will support a useful comparison for this line." The applicant proposes to use the Periodic Surveillance and Preventive Maintenance Program to manage loss of material for copper alloy in this treated water environment. SER Section 3.0.3.3.7 documents the staff's evaluation of this program. The staff's evaluation of this material/environment/aging effect/AMP combination is documented in SER Section 3.3A.2.3.11. Based on the above, the staff finds the applicant's AMR results acceptable.

The LRA table referenced Note H for stainless steel expansion joint and carbon steel silencer and piping, all exposed to an internal environment of exhaust gas, with an aging effect of "cracking-fatigue," and the AMP as "TLAA – metal fatigue." Note H indicates that the aging effect is not identified in the GALL Report for the component/material/environment combination. The staff's evaluation of the metal fatigue TLAAs is documented in SER Section 4.3.2. During an audit, the staff questioned the applicant about these AMR results, to gain a better understanding of the conditions and how cracking would be managed (Audit Item 232). In its response, dated December 18, 2007, the applicant provided additional explanation of the conditions potentially leading to cracking and the consequences of a crack on performance of intended function. The staff reviewed this information and concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences. On this basis, the staff finds the applicant's AMR results to be acceptable for these combinations.

The LRA table referenced Note H for stainless steel piping, strainer, thermowell, tubing, and valve body exposed to an internal or external environment of lube oil with an aging effect of cracking, and the Oil Analysis Program as the AMP. The staff's evaluation of the Oil Analysis Program is documented in SER Section 3.0.3.2.12. The staff determined that the aging effect of cracking is an appropriate aging effect to manage for the above combination because contaminants in the oil such as water and chlorides can cause cracking of stainless steel. The Oil Analysis Program maintains oil systems free of contaminants (primarily water and particulates) to preserve an environment that is not conducive to loss of material, cracking, or fouling. Because the AMP manages cracking, the staff finds that the aging effect of cracking will be adequately managed during the period of extended operation.

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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3B.2.3.11 Security Generator System - Summary of Aging Management Review – LRA Table 3.3.2-15-IP3

The staff reviewed LRA Table 3.3.2-15-IP3, which summarizes the results of AMR evaluations for the security generator system component groups.

The LRA table referenced Note H for aluminum heat exchanger fins exposed to air-indoor (external) with the aging effect fouling which will be managed by the Periodic Surveillance and Preventive Maintenance Program. The staff's evaluation of this program is documented in SER Section 3.0.3.3.7. This program will use visual or other NDE techniques to inspect the surface condition of the radiator tubes and fins to manage loss of material on external surfaces. The staff's evaluation of this material/environment/aging effect/AMP combination is documented in SER Section 3.3A.2.3.12. Therefore, the staff finds the applicant's AMR results acceptable.

The LRA table, as amended by letter dated June 30, 2009, referenced Note H for carbon steel piping, silencer, and valve body, and stainless steel flexible bellows exposed to an internal environment of exhaust gas with an aging effect of "cracking-fatigue," and an AMP of Periodic Surveillance and Preventive Maintenance. Note H indicates that the aging effect is not identified in the GALL Report for the component/material/environment combination. The staff's evaluation of the Periodic Surveillance and Preventive Maintenance is documented in SER Section 3.0.3.3.7. The staff's evaluation of this material/environment/aging effect/AMP combination is documented in SER Section 3.3A.2.3.12. Therefore, the staff finds the applicant's AMR results acceptable.

By letter dated June 30, 2009, the applicant submitted an annual update to the LRA, identifying changes made to the CLB that materially affects the contents of the LRA. The applicant changed the material for the heat exchanger bonnets from copper alloy greater than 15 percent zinc to fiberglass. The applicant referenced Note F for these components exposed externally to indoor air, with the aging effect and aging management program listed as "none." For the fiberglass heat exchanger bonnet exposed to treated water, the applicant listed the aging effect and AMP as "none." The staff notes that fiberglass has excellent resistance to indoor air and is commonly used for insulation (J.F. Malloy, "Thermal Insulation," Van Nostrand Reinhold Company, Copyright 1969). The staff also notes that fiberglass has excellent resistance to water and is commonly used for boat hulls. On the basis that the fiberglass liner is located in the in an environment in which the radioactivity level is negligible, the staff finds that fiberglass will not have any aging effects requiring management in indoor air and treated water.

In the letter dated June 30, 2009, the applicant changed the material for heat exchanger tubes from copper alloy greater than 15 percent zinc to aluminum exposed to internally to treated water and externally to indoor air with an intended function of heat transfer. The applicant listed the aging effect as fouling for exposure to indoor air and proposed the Periodic Surveillance and Preventive Maintenance Program to manage this aging effect. The applicant also listed the aging effect of fouling for exposure to treated water and proposed the Water Chemistry Control – Closed Cooling Water Program. For both entries, the applicant listed Note F, which states this material is not in the GALL Report for this component. The staff's evaluation of these AMPs is documented in SER Sections 3.0.3.3.7 and 3.0.3.2.16, respectively. The staff notes that fouling of the exterior of the heat exchanger tubing could occur by the accumulation of dust, and is an effect that can satisfactorily be managed by the PSPM Program, which performs periodic visual inspections during surveillance and maintenance activities for those components within the scope of license renewal. The staff notes that although fouling of aluminum in treated water is not expected, it can effectively be managed using the Water Chemistry Control – Closed Cooling Water program, which includes chemistry activities that monitor and control closed cooling water chemistry using industry guidelines for closed cooling water. Based on its review, the staff determines that due to activities performed as part of PSPM Program and the Water Chemistry Control – Closed Cooling Water Program, the aging effect of fouling will be adequately managed for aluminum exposed to indoor air and closed cycle cooling water. Therefore, the staff finds the applicant's AMR results acceptable.

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

3.3B.2.3.12 Appendix R Diesel Generator System - Summary of Aging Management Review – LRA Table 3.3.2-16-IP3

The staff reviewed LRA Table 3.3.2-16-IP3, which summarizes the results of AMR evaluations for the Appendix R diesel generator system component groups.

The LRA table referenced Note G for aluminum heat exchanger fins externally exposed to outdoor air; copper alloy heat exchanger fins externally exposed to air-indoor; and copper alloy >15 percent zinc and copper alloy >15 percent zinc (inhibited) heat exchanger tubes externally exposed to air-indoor and outdoor air, respectively. The aging effect and AMP listed for the above material/environment combinations is fouling and the Periodic Surveillance and Preventive Maintenance Program. The staff's review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.3.7. This program uses periodic visual inspections or other NDEs to inspect the internal surface condition of the engine turbocharger and aftercooler housing including external surfaces of tubes and fins to manage loss of material and fouling. Because these components will be periodically inspected for loss of material and fouling, the staff finds the applicant's results acceptable.

The LRA table also referenced Note G for copper alloy >15 percent zinc (inhibited) heat exchanger tubes and stainless steel valve bodies externally exposed to outdoor air with an aging effect of loss of material which is to be managed by the External Surfaces Monitoring Program. The staff's review of the program is documented in SER Section 3.0.3.2.5. This program will use periodic plant system inspections and walkdowns to monitor for material degradation and leakage. Because these components will be periodically inspected for loss of material, the staff finds the applicant's results acceptable.

The LRA referenced Note H for stainless steel valve body internally exposed to lube oil with an aging effect of cracking managed by the Oil Analysis Program. The staff's evaluation of this program is documented in SER Section 3.0.3.2.12. As documented in SER Section 3.3A.2.3.13, the staff determined that the aging effect of cracking is an appropriate aging effect to manage for the above combination because contaminates in the oil such as water and chlorides can cause cracking of stainless steel. The Oil Analysis Program maintains oil systems free of contaminants (primarily water and particulates) to preserve an environment that is not conducive to loss of material, cracking, or fouling. Because the AMP manages cracking, the staff finds that the aging effect of cracking will be adequately managed during the period of extended operation.

The LRA table referenced Note H for carbon steel expansion joint, piping, and silencer exposed to an internal environment of exhaust gas with an aging effect “cracking-fatigue” and the AMP as Periodic Surveillance and Preventive Maintenance. During an audit, the staff questioned the applicant about these AMR results, to gain a better understanding of the conditions and how cracking would be managed (Audit Item 232). In its response, dated December 18, 2007, the applicant provided additional explanation of the conditions potentially leading to cracking and the consequences of a crack on performance of intended function. The staff reviewed this information and concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences. On this basis, the staff finds the applicant’s AMR results to be acceptable for these combinations.

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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3B.2.3.13 City Water System - Summary of Aging Management Review – LRA Table 3.3.2-17-IP3

The staff reviewed LRA Table 3.3.2-17-IP3, which summarizes the results of AMR evaluations for the city water system component groups.

The LRA table referenced Note G and plant-specific Note 305 for carbon steel piping and valve body, gray cast iron piping, copper alloy tubing, and copper alloy >15 percent zinc valve body exposed to an internal environment of treated water. The aging effect listed for these material/environment combinations is loss of material. Note 305 states “[t]his treated water environment includes water that has been treated but is not maintained by a chemistry control program, such as water from the city water system. There is no environment in the GALL Report that will support a useful comparison for this line.” The applicant credits the Periodic Surveillance and Preventive Maintenance Program to manage loss of material for carbon steel, copper alloy, and gray cast iron in this treated water environment. SER Section 3.0.3.3.7 documents the staff’s evaluation of this program. The staff’s evaluation of the above component/material/environment/aging effect/AMP combination is documented in SER Section 3.3A.2.3.14. As documented in that section, the staff finds the applicant’s AMR results acceptable.

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

3.3B.2.3.14 Plant Drains - Summary of Aging Management Review – LRA Table 3.3.2-18-IP3

The staff reviewed LRA Table 3.3.2-18-IP3, which summarizes the results of AMR evaluations for the plant drains component groups.

The LRA table referenced Note G for stainless steel bolting and piping exposed to an external environment of outdoor air, with the aging effect of loss of material. The applicant proposed to manage the aging of the bolting and the piping by the Bolting Integrity Program and the External Surfaces Monitoring Program, respectively. The staff's evaluation of these programs is documented in SER Sections 3.0.3.2.2 and 3.0.3.2.5, respectively. The staff's evaluation of the above material/environment combinations is documented in SER Section 3.3A.2.3.15. As stated in that section, the staff finds that, because these components will be inspected periodically for loss of material, the aging effect for these component/environment combinations will be effectively managed by the respective programs.

In a letter dated June 30, 2009, the applicant added drain piping and float valve to LRA Table 3.3.2-18-IP3. These additional AMR line items reference Note F for plastic piping exposed to indoor air on the internal surface, and exposed to indoor air or soil on the external surface. The aging effect and AMP are listed as "none." No aging effect would be expected because there are no stressors for plastics for the named environments. Typical stressors are exposure to UV radiation, high temperatures, and oxidizing conditions. In addition, the staff notes that plastic piping is used extensively in gas distribution systems and is exposed to soil with no adverse effects caused by the soil, which poses a more aggressive environment than indoor air. The staff has not identified any age-related industry experience for plastic material in indoor air and soil environments. Therefore, the staff finds the applicant's AMR results to be acceptable.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging 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).

3.3B.2.3.15 Ammonia / Morpholine Addition System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-1-IP3

The staff reviewed LRA Table 3.3.2-19-1-IP3, which summarizes the results of AMR evaluations for the ammonia / morpholine addition system component groups.

The LRA table referenced Note G and plant-specific Note 318 for stainless steel piping and valve bodies exposed to an internal environment of treated water with loss of material as the aging effect. The applicant proposed the One-Time Inspection Program as the AMP. Note 318 states "[t]his treated water environment includes chemical solutions used to control primary and secondary system water chemistry or as an additive for containment spray." The One-Time Inspection Program is credited to confirm the absence of loss of material. The above material/environment combination is similar to other combinations in the GALL Report (e.g., Table VIII.B, Line Item B1-4 and Table VIII.G Line Item G-32) which recommend water chemistry control augmented by a one-time inspection to verify the effectiveness of the water chemistry. Because the water chemistry is controlled by plant procedures and will be verified by the One-Time Inspection Program, the staff finds the applicant's AMR result acceptable.

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

3.3B.2.3.16 Auxiliary Steam and Condensate Return System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-2-IP3

The staff reviewed LRA Table 3.3.2-19-2-IP3, which summarizes the results of AMR evaluations for the auxiliary steam and condensate return system component groups.

The LRA table referenced Note G for stainless steel tubing and valve bodies exposed to an internal environment of steam with an aging effect of cracking-fatigue. The applicant referenced this combination as a metal fatigue TLAA. The staff's evaluation of the metal fatigue TLAAs is documented in SER Section 4.3.2. During an audit, the staff questioned the applicant about these AMR results, to gain a better understanding of the conditions and how cracking would be managed (Audit Item 233). In its response, dated December 18, 2007, the applicant provided additional explanation of the conditions potentially leading to cracking and the consequences of a crack on performance of intended function. The staff reviewed this information and concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences. Therefore, the staff finds the applicant's AMR results acceptable.

The LRA table referenced Note G for copper alloy >15 percent zinc valve body exposed to an internal environment of steam with an aging effect of loss of material which will be managed by the Water Chemistry Program-Primary and Secondary Program. The staff's evaluation of this program is documented in SER Section 3.0.3.2.17. The program includes periodic monitoring and control of known detrimental contaminants such as chlorides, fluorides, dissolved oxygen, and sulfate concentrations below the levels known to result in loss of material or cracking. Water chemistry control is in accordance with industry guidelines such as EPRI TR-105714 for primary water chemistry, and EPRI TR-102134 for secondary water chemistry. The One-Time Inspection Program for Water Chemistry utilizes inspections or NDEs of representative samples to verify that the Water Chemistry Control – Primary and Secondary Program has been effective at managing aging effects. Because chemistry will be monitored, and the One-Time Inspection Program will verify the effectiveness of the water chemistry control, the staff finds the applicant's AMR results for this material/environment combination acceptable.

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

3.3B.2.3.17 Boron and Layup Chemical Addition System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-3-IP3

The staff reviewed LRA Table 3.3.2-19-3-IP3, which summarizes the results of AMR evaluations for the boron and layup chemical addition system component groups.

The LRA table referenced Note G and plant-specific Note 318 for stainless steel piping, pump casing, sight glass, tank, tubing, and valve body exposed to an internal environment of treated water. The applicant proposed the One-Time Inspection program to manage the aging effect of loss of material. As stated above in SER Section 3.3B.2.3.15, the One-Time Inspection Program is credited to confirm the absence of loss of material. The above material/environment combination is similar to other combinations in the GALL Report (e.g., Table VIII.B, Line Item B1-4 and Table VIII.G Line Item G-32) which recommend water chemistry control augmented by a one-time inspection to verify the effectiveness of the water chemistry. Because the water chemistry is controlled by plant procedures and will be verified by the One-Time Inspection Program, the staff finds the applicant's AMR result acceptable.

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

3.3B.2.3.18 Condenser Air Removal System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-4-IP3

The staff reviewed LRA Table 3.3.2-19-4-IP3, which summarizes the results of AMR evaluations for the condenser air removal system component groups.

The LRA table referenced Note F for CASS valve bodies exposed to an internal environment of steam. The table also referenced Note G for stainless steel piping and valve bodies exposed to the same environment. The aging effect is listed as cracking –fatigue, and the AMP is listed as "TLAA-metal fatigue." The staff's review of the metal fatigue TLAAs is documented in SER Section 4.3.2. During an audit, the staff questioned the applicant about these AMR results, to gain a better understanding of the conditions and how cracking would be managed (Audit Item 233). In its response, dated December 18, 2007, the applicant provided additional explanation of the conditions potentially leading to cracking and the consequences of a crack on performance of intended function. The staff reviewed this information and concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences. Therefore, the staff finds the applicant's AMR results acceptable.

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

3.3B.2.3.19 Chlorination System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-5-IP3

The staff reviewed LRA Table 3.3.2-19-5-IP3, which summarizes the results of AMR evaluations for the chlorination system component groups.

The table referenced Note G and plant-specific Note 305 for gray cast iron piping and valve bodies exposed to an internal environment of treated water with loss of material as the aging effect which will be managed using the Periodic Surveillance and Preventive Maintenance Program. The staff's review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.3.7. Note 305 states "[t]his treated water environment includes water that has been treated but is not maintained by a chemistry control program, such as water from the city water system. There is no environment in the GALL Report that will support a useful comparison for this line." As described in the Periodic Surveillance and Preventive Maintenance Program, the applicant will use visual or other NDE techniques to inspect a representative sample of the gray cast iron piping and valve bodies exposed to treated water to manage the aging effect. The staff finds that visual or NDE techniques are adequate for detecting loss of material in piping systems and valves exposed to treated water. The staff finds the applicant's AMR results to be appropriate.

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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3B.2.3.20 Containment Spray System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-10-IP3

The staff reviewed LRA Table 3.3.2-19-10-IP3, which summarizes the results of AMR evaluations for the containment spray system component groups.

The LRA referenced Note G and plant-specific Note 318 for stainless steel piping and valve bodies internally exposed to treated water with an aging effect of loss of material which will be managed by the Water Chemistry Program – Primary and Secondary. The staff's evaluation of this program is documented in SER Section 3.0.3.2.17. The program includes periodic monitoring and control of known detrimental contaminants such as chlorides, fluorides, dissolved oxygen, and sulfate concentrations below the levels known to result in loss of material or cracking. Water chemistry control is in accordance with industry guidelines such as EPRI TR-105714 for primary water chemistry, and EPRI TR-102134 for secondary water chemistry. During an audit, the staff questioned the applicant about whether or not the One-Time Inspection Program is also credited to verify the effectiveness of the Water Chemistry Control - Primary and Secondary (Audit Item 72). In its response, dated December 18, 2007, the applicant confirmed that the One-Time Inspection Program will be used to verify the effectiveness of the Water Chemistry Programs, including the Water Chemistry Program – Primary and Secondary. The One-Time Inspection Program for Water Chemistry utilizes inspections or NDEs of representative samples to verify that the Water Chemistry Control – Primary and Secondary Program has been effective at managing aging effects. Because chemistry will be monitored, and the One-Time Inspection Program will verify the effectiveness of the water chemistry control, the staff finds the applicant's AMR results for this material/environment combination acceptable.

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

3.3B.2.3.21 City Water Makeup System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-13-IP3

The staff reviewed LRA Table 3.3.2-19-13-IP3, which summarizes the results of AMR evaluations for the city water makeup system component groups.

The LRA table referenced Note G and plant-specific Note 305 for carbon steel piping, pump casing, and strainer housing; copper alloy piping and valve body; copper alloy >15 percent zinc valve body; and gray cast iron valve body all exposed to an internal environment of treated water. The aging effect listed for these material/environment combinations is loss of material. The applicant credits the Periodic Surveillance and Preventive Maintenance Program to manage loss of material for the above material/environment combinations. The staff's evaluation of the AMR results for the city water makeup system nonsafety-related components is documented in SER Section 3.3A.2.3.19. As stated in that section, the staff determined that visual or NDE techniques are adequate for detecting loss of material in the city water system components exposed to treated water.

For stainless steel tubing and CASS valve body exposed to treated water, the applicant proposed the One-Time Inspection Program to manage the loss of material. The staff's evaluation of this program is documented in SER Section 3.0.3.1.9. This program also uses NDE techniques to monitor for loss of material. The staff verified that the One-Time Inspection Program includes monitoring of the internal surfaces of city water system stainless steel and CASS components containing treated water. Based on the above, the staff finds that the applicant's AMR results are acceptable.

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

3.3B.2.3.22 Emergency Diesel Generator System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-16-IP3

The staff reviewed LRA Table 3.3.2-19-16-IP3, which summarizes the results of AMR evaluations for the emergency diesel generator system component groups.

The LRA table referenced Note H for carbon steel piping exposed internally to condensation with an aging effect of cracking-fatigue which was identified by the applicant as a TLAA. The staff's review of the metal fatigue TLAAs is documented in SER Section 4.3.2. During an audit, the staff questioned the applicant about these AMR results, to gain a better understanding of the conditions and how cracking would be managed (Audit Item 233). In its response, dated December 18, 2007, the applicant provided additional explanation of the conditions potentially leading to cracking and the consequences of a crack on performance of intended function. The staff reviewed this information and concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences. Therefore, the staff finds the applicant's AMR results acceptable.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report.

3.3B.2.3.23 Extraction Steam System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-18-IP3

The staff reviewed LRA Table 3.3.2-19-18-IP3, which summarizes the results of AMR evaluations for the extraction steam system component groups.

The LRA referenced Note H for stainless steel expansion joints, orifices, piping, thermowells, tubing, and valve bodies exposed to an internal environment of steam with an aging effect of cracking-fatigue which is a TLAA. The staff's review of the metal fatigue TLAAs is documented in SER Section 4.3.2. As stated in the above section, the staff questioned the applicant about these AMR results (Audit Item 233). In its response, dated December 18, 2007, the applicant provided additional explanation of the conditions potentially leading to cracking and the consequences of a crack on performance of intended function. The staff reviewed this information and concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences. On this basis, the staff finds the applicant's AMR results to be acceptable for these combinations.

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.

3.3B.2.3.24 Fire Water System, Nonsafety-Related Components Potentially Affecting Safety Functions – Summary of Aging Management Review LRA Table 3.3.2-19-20-IP3

The staff reviewed LRA Table 3.3.2-19-20-IP3, which summarizes the results of AMR evaluations for the fire water system component groups.

The LRA referenced Note G for carbon steel piping, tank, and valve bodies exposed to fire protection foam (internal) with an aging effect of loss of material managed by the Fire Water System Program. As stated in Table IX.C of the GALL Report, carbon steel is vulnerable to general, pitting, and crevice corrosion which causes a loss of material. The staff's evaluation of the Fire Water System Program is documented in SER Section 3.0.3.2.8. This program is being enhanced to inspect the internal surface of foam-based fire suppression tanks. In addition, the program performs wall thickness evaluations of fire protection piping are performed on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion. Because the Fire Water System Program will monitor for the loss of material, the staff finds that the applicant's AMR results are acceptable.

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

3.3B.2.3.25 Main Feedwater Pump and Services, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-23-IP3

The staff reviewed LRA Table 3.3.2-19-23-IP3, which summarizes the results of AMR evaluations for the main feedwater pump and services component groups.

The LRA table referenced Note H for stainless steel expansion joints, piping, and valve bodies internally exposed to steam with an aging effect of cracking-fatigue which was identified by the applicant as a TLAA. The staff's review of the metal fatigue TLAAs is documented in SER Section 4.3.2. As noted previously, the staff questioned the applicant about these AMR results (Audit Item 233). In its response, dated December 18, 2007, the applicant provided additional explanation of the conditions potentially leading to cracking and the consequences of a crack on performance of intended function. The staff reviewed this information and concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences. On this basis, the staff finds the applicant's AMR results to be acceptable for these combinations.

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.

3.3B.2.3.26 Gland Seal Steam System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-24-IP3

The staff reviewed LRA Table 3.3.2-19-24-IP3, which summarizes the results of AMR evaluations for the gland seal steam system component groups.

The LRA referenced Note G for nickel alloy rupture disks exposed to an internal environment of steam with three aging effects: (1) cracking which is managed by the Water Chemistry Control – Primary and Secondary; (2) cracking-fatigue which is a TLAA; and (3) loss of material which is managed by the Water Chemistry Control – Primary and Secondary. The staff's review of the AMP is documented in SER Section 3.0.3.2.17, and the staff's evaluation of the metal fatigue TLAA is documented in SER Section 4.3.2. As stated above and for the reason stated, the staff finds the applicant's AMR result for the aging effect of cracking-fatigue acceptable. The GALL Report has line items for steam generator tubes made of nickel alloy exposed to secondary feedwater/steam with the aging effect of cracking and loss of material and lists the Steam Generator Integrity Program and the Water Chemistry Program to manage these aging effects (GALL Report Table IV.D1, Line Items D1-23, D1-24, and D1-25) and one line item for nickel alloy piping, piping elements, and piping components with the Water Chemistry Program to manage loss of material (Chapter VIII.B1, Line Item B1-1). The Steam Generator Integrity Program is not applicable to rupture disks. The Water Chemistry Control – Primary and Secondary Program includes periodic monitoring and control of known detrimental contaminants such as chlorides, fluorides, dissolved oxygen, and sulfate concentrations below the levels known to result in loss of material or cracking. Water chemistry control is in accordance with industry guidelines such as EPRI TR-105714 for primary water chemistry, and EPRI TR-102134 for secondary water chemistry. Because the water chemistry will be periodically monitored, the staff finds that the AMR line items are acceptable for these combinations of material and environment.

The LRA referenced Note H for stainless steel piping, tubing, and valve bodies where the aging effect is cracking-fatigue which was identified by the applicant as a TLAA. The staff's review of the metal fatigue TLAAs is documented in SER Section 4.3.2. As stated in the above section for the reasons given, the staff finds the applicant's AMR results to be acceptable for these combinations.

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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3B.2.3.27 Hydrazine Addition System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-26-IP3

The staff reviewed LRA Table 3.3.2-19-26-IP3, which summarizes the results of AMR evaluations for the hydrazine addition system component groups.

The LRA referenced Note G and plant-specific Note 318 for stainless steel piping, pump casing, sight glass, tank, and valve body exposed to an internal environment of treated water. The applicant proposed the One-Time Inspection program to manage the aging effect of loss of material. The staff's evaluation of the One-Time Inspection Program is documented in SER Section 3.0.3.1.9. As stated above in SER Section 3.3B.2.3.15, the One-Time Inspection Program is credited to confirm the absence of loss of material. The above material/environment combination is similar to other combinations in the GALL Report (e.g., Table VIII.B, Line Item B1-4 and Table VIII.G Line Item G-32) which recommend water chemistry control augmented by a one-time inspection to verify the effectiveness of the water chemistry. Because the water chemistry is controlled by plant procedures and will be verified by the One-Time Inspection Program, the staff finds the applicant's AMR result acceptable.

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

3.3B.2.3.28 Heater Drain / Moisture Separator Drains / Vents System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-27-IP3

The staff reviewed LRA Table 3.3.2-19-27-IP3, which summarizes the results of AMR evaluations for the heater drain / moisture separator drains / vents system component groups.

The LRA referenced Note G for sight glass internally exposed to steam with the aging effect and AMP listed as "none." Although the GALL Report does not contain an entry for glass exposed to steam, it does contain entries for other environments for glass. In all cases, the aging effect and AMP are listed as "none." Glass does not experience degradation absent a hydrofluoric acid environment. Because hydrofluoric acid is not used in the systems containing these components, the staff finds the applicant's AMR results for glass exposed to steam acceptable.

The LRA referenced Note H for stainless steel expansion joints, orifices, piping, tubing and valve bodies internally exposed to steam (internal) with an aging effect of cracking-fatigue which was identified by the applicant as a TLAA. The staff's review of the metal fatigue TLAAs is documented in SER Section 4.3.2. The staff questioned the applicant about these AMR results, to gain a better understanding of the conditions and how cracking would be managed (Audit Item 233). In its response, dated December 18, 2007, the applicant provided additional explanation of the conditions potentially leading to cracking and the consequences of a crack on performance of intended function. The staff reviewed this information and concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences. On this basis, the staff finds the applicant's AMR results to be acceptable for these combinations.

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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3B.2.3.29 High Pressure Steam Dump System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-28-IP3

The staff reviewed LRA Table 3.3.2-19-28-IP3, which summarizes the results of AMR evaluations for the high pressure steam dump system component groups.

The LRA referenced Note H for stainless steel tubing exposed to an internal environment of steam with an aging effect cracking-fatigue which was identified by the applicant as a TLAA. The staff's review of the metal fatigue TLAAs is documented in SER Section 4.3.2. The staff's evaluation of this AMR result for the material/environment combination is documented in SER Section 3.3B.2.3.28.

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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3B.2.3.30 Low Pressure Steam Dump System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-32-IP3

The staff reviewed LRA Table 3.3.2-19-32-IP3, which summarizes the results of AMR evaluations for the low pressure steam dump system component groups.

The LRA referenced Note H for stainless steel tubing where the aging effect is cracking-fatigue which was identified by the applicant as a TLAA. The staff's review of the metal fatigue TLAAs is documented in SER Section 4.3.2. The staff's evaluation of this AMR result for the material/environment combination is documented in SER Section 3.3B.2.3.28.

The LRA referenced Note I and plant specific Note 310 for carbon steel bolting, piping, steam trap, strainer housing, and valve bodies externally exposed to air-indoor with no aging effect or aging management program. Note 310 states “[t]hese components remain at high temperature during normal operation which precludes moisture condensation and the resulting corrosion.” The components referenced are carbon steel bolting, piping, steam trap, strainer housing, and valve bodies exposed to an external environment of indoor air with no aging effect or AMP. A similar material/environment/aging effect/AMP combination exists in GALL Report Table VII.J Line Item J-20. The environment in this GALL Report line item is controlled indoor air which means that the air is controlled for humidity. The applicant stated that the components remain at high temperatures which results in low humidity. Because these two environments are similar, the staff finds the applicant’s AMR result acceptable.

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

3.3B.2.3.31 Liquid Waste Disposal System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-33-IP3

The staff reviewed LRA Table 3.3.2-19-33-IP3, which summarizes the results of AMR evaluations for the liquid waste disposal system component groups.

The LRA referenced Note G and plant-specific Note 305 for carbon and stainless steel piping and valve bodies exposed to an internal environment of treated water with an aging effect of loss of material. Note 305 states, “[t]his treated water environment includes water that has been treated but is not maintained by a chemistry control program, such as water from the city water system. There is no environment in the GALL Report that will support a useful comparison for this line.” The applicant proposed to use the Periodic Surveillance and Preventive Maintenance AMP to manage loss of material for carbon steel components in this treated water environment, and One-Time Inspection to confirm no loss of material for the stainless steel components. The staff’s review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.3.7. As described in the Periodic Surveillance and Preventive Maintenance Program, the applicant will use visual or other NDE techniques to inspect a representative sample of the carbon steel piping and valve bodies exposed to treated water to manage the aging effect. The staff finds that visual or NDE techniques are adequate for detecting loss of material in piping systems and valves exposed to treated water. The staff finds the applicant’s AMR results to be acceptable.

For stainless steel piping and valve body exposed to treated water, the applicant proposed the One-Time Inspection Program to manage the loss of material. The staff’s evaluation of this program is documented in SER Section 3.0.3.1.9. This program also uses NDE techniques to monitor for loss of material. The staff verified that the One-Time Inspection Program includes monitoring of the internal surfaces of the water treatment plant system stainless steel components containing treated water. Based on the above, the staff finds that the applicant’s AMR results are acceptable.

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

3.3B.2.3.32 Main Feedwater System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-34-IP3

The staff reviewed LRA Table 3.3.2-19-34-IP3, which summarizes the results of AMR evaluations for the main feedwater system component groups.

The LRA referenced Note I and plant specific Note 310 for carbon steel bolting, flow element, filter housing, heat exchanger shell, piping, thermowell, and valve bodies externally exposed to air-indoor with no aging management effect or aging management program. Note 310 states "[t]hese components remain at high temperature during normal operation which precludes moisture condensation and the resulting corrosion." The components referenced are carbon steel bolting, piping, steam trap, strainer housing, and valve bodies exposed to an external environment of indoor air with no aging effect or AMP. A similar material/environment/aging effect/AMP combination exists in GALL Report Table VII.J Line Item J-20. The environment in this GALL Report line item is controlled indoor air which means that the air is controlled for humidity. The applicant stated that the components remain at high temperatures which results in low humidity. Because these two environments are similar, the staff finds the applicant's AMR result acceptable.

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

3.3B.2.3.33 Main Steam System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-35-IP3

The staff reviewed LRA Table 3.3.2-19-35-IP3, which summarizes the results of AMR evaluations for the main steam system component groups.

The LRA referenced Note H for stainless steel piping, tubing, and valve body exposed to an internal environment of steam where the aging effect is cracking-fatigue which was identified by the applicant as a TLAA. The staff's review of the metal fatigue TLAAs is documented in SER Section 4.3.2. The staff's evaluation of the AMR result for this material/environment combination is documented in SER Section 3.3B.2.3.28.

The LRA referenced Note I and plant-specific Note 310 for carbon steel bolting, orifice, piping, silencer, steam trap, strainer housing, thermowell, and valve body externally exposed to air-indoor with no aging management effect or aging management program. The staff's evaluation of this material/environment is documented in SER Section 3.3B.2.3.32.

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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3B.2.3.34 Main Turbine Generator System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-36-IP3

The staff reviewed LRA Table 3.3.2-19-36-IP3, which summarizes the results of AMR evaluations for the main turbine generator system component groups.

The LRA referenced Note H for stainless steel rupture disc exposed to an internal environment of steam where the aging effect is cracking-fatigue which was identified by the applicant as a TLAA. The staff's review of the metal fatigue TLAAs is documented in SER Section 4.3.2. The staff's evaluation of the AMR result for this material/environment combination is documented in SER Section 3.3B.2.3.28.

The LRA referenced Note I and plant-specific Note 310 for carbon steel bolting, piping, turbine housing, and valve body externally exposed to air-indoor with no aging management effect or aging management program. The staff's evaluation of this material/environment is documented in SER Section 3.3B.2.3.32.

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.

3.3B.2.3.35 Primary Plant Sampling System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-41-IP3

The staff reviewed LRA Table 3.3.2-19-41-IP3, which summarizes the results of AMR evaluations for the primary plant sampling system component groups.

The LRA referenced Note G for stainless steel piping and valve body exposed to an internal steam environment where the aging effect is cracking-fatigue which was identified by the applicant as a TLAA. The staff's review of the metal fatigue TLAAs is documented in SER Section 4.3.2. The staff's evaluation of the AMR result for this material/environment combination is documented in SER Section 3.3B.2.3.28.

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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3B.2.3.36 Pressurizer System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-43-IP3

The staff reviewed LRA Table 3.3.2-19-43-IP3, which summarizes the results of AMR evaluations for the pressurizer system component groups.

The LRA table referenced Note F and plant-specific Note 313 for carbon steel tank exposed to treated water with an aging effect of loss of material. Note 313 states "[t]he tank is steel with a corrosion-resistant coating on the wetted surfaces (AMERCOAT 55 System)." The applicant proposed the Periodic Surveillance and Preventive Maintenance Program to manage loss of material. The staff's review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.3.7. The use of the Periodic Surveillance and Preventive Maintenance Program for the material/environment combination is appropriate because the tank will be periodically inspected using visual inspection or other NDE methods to detect loss of material. Therefore, the staff finds the applicant's AMR result acceptable.

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

3.3B.2.3.37 Reheat Steam System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-45-IP3

The staff reviewed LRA Table 3.3.2-19-45-IP3, which summarizes the results of AMR evaluations for the reheat steam system component groups.

The LRA referenced Note H for stainless steel tubing exposed to an internal environment of steam where the aging effect is cracking-fatigue which was identified by the applicant as a TLAA. The staff's review of the metal fatigue TLAAs is documented in SER Section 4.3.2. The staff's evaluation of the AMR result for this material/environment combination is documented in SER Section 3.3B.2.3.28.

The LRA referenced Note I and plant-specific Note 310 for carbon steel bolting, flow element, heat exchanger shell, piping, steam trap, strainer housing, thermowell and valve body externally exposed to air-indoor with no aging management effect or aging management program. The staff's evaluation of this material/environment is documented in SER Section 3.3B.2.3.32.

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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3B.2.3.38 Steam Generator Sampling System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-52-IP3

The staff reviewed LRA Table 3.3.2-19-52-IP3, which summarizes the results of AMR evaluations for the SG sampling system component groups.

The LRA referenced Note G and plant-specific Note 305 for carbon steel heat exchanger shell exposed to treated water (external) with an aging effect of loss of material. Note 305 states "[t]his treated water environment includes water that has been treated but is not maintained by a chemistry control program, such as water from the city water system. There is no environment in the Gall Report that will support a useful comparison for this line." The applicant proposed to use the Periodic Surveillance and Preventive Maintenance AMP to manage loss of material for carbon steel components in this treated water environment. The staff's review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.3.7. As described in the Periodic Surveillance and Preventive Maintenance Program, the applicant will use visual or other NDE techniques to inspect a representative sample of the carbon steel components exposed to treated water to manage the aging effect. The staff finds that visual or NDE techniques are adequate for detecting loss of material in carbon steel components exposed to treated water. The staff finds the applicant's AMR results to be acceptable.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging 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).

3.3B.2.3.39 Secondary Plant Sampling System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-55-IP3

The staff reviewed LRA Table 3.3.2-19-55-IP3, which summarizes the results of AMR evaluations for the secondary plant sampling system component groups.

The LRA table referenced Note G and plant-specific Note 305 for carbon steel heat exchanger shell exposed to an external environment of treated water with an aging effect of loss of material to be managed by the Periodic Surveillance and Preventive Maintenance Program. As stated in the previous section of this SER, the staff finds that visual or NDE techniques are adequate for detecting loss of material in carbon steel components exposed to treated water. Therefore, the staff finds the applicant's AMR results to be acceptable.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging 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).

3.3B.2.3.40 Vapor Containment Hydrogen Analyzer System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-59-IP3

The staff reviewed LRA Table 3.3.2-19-59-IP3, which summarizes the results of AMR evaluations for the vapor containment hydrogen analyzer system component groups.

The LRA table referenced Note G for stainless steel gas analyzer, piping, tank, and valve body internally exposed to air-indoor with no aging effect requiring management and no AMP required. This material/environment combination is similar to other material/environment combinations in the GALL Report (e.g., Table VII.J, Line Items J-15 and J-18) which list the aging effect and AMP as "none." Therefore, the staff finds the applicant's AMR results acceptable.

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

3.3B.2.3.41 Building Vent Sampling System, Nonsafety-Related Components Potentially Affecting Safety Functions - Summary of Aging Management Review – LRA Table 3.3.2-19-63-IP3

In response to RAI 2.3A.2.2-1, by letter dated March 12, 2008, the applicant revised the LRA to add the building vent sampling system to the scope of license renewal. In addition, the applicant added LRA Table 3.3.2-19-63-IP3, which summarizes the results of AMR evaluations for the building vent sampling system component groups. The staff reviewed LRA Table 3.3.2-19-63-IP3.

The LRA referenced Note G for stainless steel filter housing, tubing, and valve bodies exposed to air-indoor (internal) with no aging effects or AMPs. This material/environment combination is similar to other material/environment combinations in the GALL Report (e.g., Table VII.J, Line Items J-15 and J-18) which list the aging effect and AMP as "none." Therefore, the staff finds the applicant's AMR results acceptable.

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

3.3.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the auxiliary systems components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will 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 following steam and power conversion system components and component groups:

- main steam
- main feedwater
- auxiliary feedwater (AFW)
- steam generator (SG) blowdown
- IP2 AFW pump room fire event
- condensate

3.4.1 Summary of Technical Information in the Application

LRA Section 3.4 provides AMR results for the steam and power conversion system components and component groups. LRA Table 3.4.1, "Summary of Aging Management Programs for the Steam and Power Conversion System Evaluated in Chapter VIII of NUREG-1801," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the steam and power conversion system components and component groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and issues identified through operating experience since the issuance of this report.

IP2 AFW Pump Room Fire Event

As stated in the LRA, the IP2 UFSAR Section 9.6.2 describes the fire protection system requirements and regulations. A combination of secondary systems and components provide a method of feeding the steam generators should a fire in the AFW pump room make it temporarily unavailable for operator actions. These plant systems and components provide feedwater flow through the main feedwater isolation valves to the steam generators from the IP1 condensate storage tanks (CST). The flowpath is from the Unit 1 CSTs through the hotwell dump and condensate transfer pump, through the condensate pumps and boiler feed pumps to the main feedwater isolation valves to the steam generators.

The applicant stated that aging management of the systems required to supply feedwater to the SGs during a fire in the AFW pump room is not based on an analysis of materials, environments, and aging effects. The components in the systems required to supply feedwater to the SGs during the short duration of the fire event are in service at the time the event occurs or their availability is checked daily. Therefore, normal plant operation continuously confirms the integrity of the systems and components required to perform their intended functions for at least 1 hour after a fire. During the event, these systems and components must continue to perform their intended functions to supply feedwater to the SGs for a minimum of 1 hour. Significant degradation that could threaten the performance of the intended functions will be apparent in the period immediately preceding the event, and sustaining continued operation will require corrective action. For the minimal 1-hour period that these systems would be required to provide makeup to the SGs, further aging degradation that would not have been apparent before the event is negligible. Therefore, the applicant has identified no aging effects and has provided no

Summary of Aging Management Review table.

Furthermore, the applicant indicated IP1 CSTs are only subject to intermittent service. Therefore, a daily check of tank levels and intermittent usage of piping and valves from the IP1 CSTs to the IP2 condenser confirm availability. Significant degradation that could threaten the performance of the intended functions will be apparent in the period immediately preceding the event and sustaining continued operation will require corrective action. The applicant stated that the use of this approach to confirm the integrity of systems required to supply water to the SGs is analogous to the approach used to confirm condenser integrity in the main steam isolation valve (MSIV) leakage pathway of BWRs. In this MSIV leakage pathway scenario, normal plant operation continuously confirms the intended function of the condenser (holdup and plateout of MSIV leakage). The applicant stated that the staff accepted the use of this approach (Section 3.4.2.4.4 of NUREG-1796, “Safety Evaluation Report Related to the License Renewal of the Dresden Nuclear Power Station, Units 2 and 3, and Quad Cities Nuclear Power Station, Units 1 and 2,” issued October 2004, and Section 3.4.2.3 of NUREG-1769, “Safety Evaluation Report Related to the License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3,” issued March 2003), concluding that main condenser integrity is continually verified during normal plant operation and that no AMP is required to ensure the intended function after an accident.

Condensate

In the LRA, the applicant stated that because condensate system components subject to an AMR are evaluated with other systems, including miscellaneous systems within the scope of 10 CFR 54.21(a)(2), it did not provide AMR tables specifically associated with the condensate system. This is further explained by the applicant in LRA Section 2.3.4.6.

3.4.2 Staff Evaluation

The staff reviewed LRA Section 3.4 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for the steam and power conversion system components, within the scope of license renewal and subject to an AMR, will be adequately managed, so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff conducted an onsite audit of AMRs to verify the applicant’s claim that certain AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate AMRs in the GALL Report. SER Section 3.0.3 documents the staff’s evaluations of the AMPs. SER Section 3.4.2.1 documents the details of the staff’s audit evaluation.

In the onsite audit, the staff also selected AMRs consistent with the GALL Report and for which it recommended further evaluation. The staff confirmed that the applicant’s further evaluations were consistent with the acceptance criteria in SRP-LR Section 3.4.2.2. SER Section 3.4.2.2 documents the staff’s audit evaluations.

The staff also conducted a technical review of the results of the remaining AMRs not consistent with, or not addressed in, the GALL Report. The technical review evaluated whether all plausible aging effects had been identified and whether the aging effects listed were appropriate for the material-environment combinations specified. SER Sections 3.4A.2.3 and 3.4B.2.3 document the staff's evaluations.

For components that the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR line items and the plant's operating experience to verify the applicant's claims.

Table 3.4-1 summarizes the staff's evaluation of components, aging effects, or mechanisms, as well as the AMPs listed in LRA Section 3.4 and addressed in the GALL Report.

Table 3.4-1 Staff Evaluation for Steam and Power Conversion System Components in the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to steam or treated water (3.4.1-1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Consistent with GALL Report (see SER Section 3.4.2.2.1)
Steel piping, piping components, and piping elements exposed to steam (3.4.1-2)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry Control—Primary and Secondary and One-Time Inspection	Consistent with GALL Report (see SER Section 3.4.2.2.2(1))
Steel heat exchanger components exposed to treated water (3.4.1-3)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry Control—Primary and Secondary and One-Time Inspection	Consistent with GALL Report (see SER Section 3.4.2.2.2.(1))
Steel piping, piping components, and piping elements exposed to treated water (3.4.1-4)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry Control—Primary and Secondary and One-Time Inspection	Consistent with GALL Report (see SER Section 3.4.2.2.2(1))
Steel heat exchanger components exposed to treated water (3.4.1-5)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.4.2.2.9)
Steel and stainless steel tanks exposed to treated water (3.4.1-6)	Loss of material due to general (steel only), pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry Control—Primary and Secondary and One-Time Inspection	Consistent with GALL Report (see SER Section 3.4.2.2.2(1))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to lubricating oil (3.4.1-7)	Loss of material due to general, pitting, and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	Oil Analysis and One-Time Inspection	Consistent with GALL Report (see SER Section 3.4.2.2.2(2))
Steel piping, piping components, and piping elements exposed to raw water (3.4.1-8)	Loss of material due to general, pitting, crevice, and microbiologically influenced corrosion and fouling	Plant specific	Yes	Periodic Surveillance and Preventive Maintenance	Consistent with GALL Report (see SER Section 3.4.2.2.3)
Stainless steel and copper alloy heat exchanger tubes exposed to treated water (3.4.1-9)	Reduction of heat transfer due to fouling	Water Chemistry and One-Time Inspection	Yes	Water Chemistry Control—Primary and Secondary and One-Time Inspection	Consistent with GALL Report (see SER Section 3.4.2.2.4(1))
Steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil (3.4.1-10)	Reduction of heat transfer due to fouling	Lubricating Oil Analysis and One-Time Inspection	Yes	Oil Analysis and One-Time Inspection	Consistent with GALL Report (see SER Section 3.4.2.2.4(2))
Buried steel piping, piping components, piping elements, and tanks (with or without coating or wrapping) exposed to soil (3.4.1-11)	Loss of material due to general, pitting, crevice, and microbiologically influenced corrosion	Buried Piping and Tank Surveillance or Buried Piping and Tank Inspection	No Yes	Buried Piping and Tank Inspection	Consistent with GALL Report (see SER Section 3.4.2.2.5(1))
Steel heat exchanger components exposed to lubricating oil (3.4.1-12)	Loss of material due to general, pitting, crevice, and microbiologically influenced corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	Oil Analysis and One-Time Inspection	Consistent with GALL Report (see SER Section 3.4.2.2.5(2))
Stainless steel piping, piping components, and piping elements exposed to steam (3.4.1-13)	SCC	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.4.2.2.6)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated water > 60 °C (> 140 °F) (3.4.1-14)	SCC	Water Chemistry and One-Time Inspection	Yes	Water Chemistry Control—Primary and Secondary, and One-Time Inspection	Consistent with GALL Report (see SER Section 3.4.2.2.6)
Aluminum and copper alloy piping, piping components, and piping elements exposed to treated water (3.4.1-15)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry Control—Primary and Secondary, and One-Time Inspection	Consistent with GALL Report (see SER Section 3.4.2.2.7(1))
Stainless steel piping, piping components, and piping elements; tanks; and heat exchanger components exposed to treated water (3.4.1-16)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry Control—Primary and Secondary, and One-Time Inspection	Consistent with GALL Report (see SER Section 3.4.2.2.7(1))
Stainless steel piping, piping components, and piping elements exposed to soil (3.4.1-17)	Loss of material due to pitting and crevice corrosion	Plant specific	Yes	Not applicable	Not applicable to IP (see SER Section 3.4.2.2.7(2))
Copper alloy piping, piping components, and piping elements exposed to lubricating oil (3.4.1-18)	Loss of material due to pitting and crevice corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	Oil Analysis and One-Time Inspection	Consistent with GALL Report (see SER Section 3.4.2.2.7(3))
Stainless steel piping, piping components, piping elements, and heat exchanger components exposed to lubricating oil (3.4.1-19)	Loss of material due to pitting, crevice, and microbiologically influenced corrosion	Lubricating Oil Analysis and One-Time Inspection	Yes	Oil Analysis and One-Time Inspection	Consistent with GALL Report (see SER Section 3.4.2.2.8)
Steel tanks exposed to air—outdoor (external) (3.4.1-20)	Loss of material due to general, pitting, and crevice corrosion	Aboveground Steel Tanks	No	Aboveground Steel Tanks	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
High-strength steel closure bolting exposed to air with steam or water leakage (3.4.1-21)	SCC, cracking due to cyclic loading,	Bolting Integrity	No	Not applicable	Not applicable to IP (see SER Section 3.4.2.1.1)
Steel bolting and closure bolting exposed to air with steam or water leakage, air—outdoor (external), or air—indoor uncontrolled (external); (3.4.1-22)	Loss of material due to general, pitting, and crevice corrosion; loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	No	Bolting Integrity	Consistent with GALL Report (see SER Section 3.4.2.1.2)
Stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water > 60 °C (> 140 °F) (3.4.1-23)	SCC	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to IP (see SER Section 3.4.2.1.1)
Steel heat exchanger components exposed to closed-cycle cooling water (3.4.1-24)	Loss of material due to general, pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	No	Water Chemistry Control—Closed-Cycle Cooling Water	Consistent with GALL Report (see SER Section 3.4.2.1.3)
Stainless steel piping, piping components, piping elements, and heat exchanger components exposed to closed-cycle cooling water (3.4.1-25)	Loss of material due to pitting and crevice corrosion	Closed-Cycle Cooling Water System	No	Water Chemistry Control—Closed-Cycle Cooling Water	Consistent with GALL Report for IP2. Not applicable to IP3 steam and power conversion systems (see SER Section 3.4.2.1.4)
Copper alloy piping, piping components, and piping elements exposed to closed-cycle cooling water (3.4.1-26)	Loss of material due to pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	No	Water Chemistry Control—Closed-Cycle Cooling Water	Consistent with GALL Report for IP2. Not applicable to IP3 steam and power conversion systems (see SER Section 3.4.2.1.5)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel, stainless steel, and copper alloy heat exchanger tubes exposed to closed-cycle cooling water (3.4.1-27)	Reduction of heat transfer due to fouling	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable to IP (see SER Section 3.4.2.1.1)
Steel external surfaces exposed to air—indoor uncontrolled (external), condensation (external), or air—outdoor (external) (3.4.1-28)	Loss of material due to general corrosion	External Surfaces Monitoring	No	External Surfaces Monitoring	Consistent with GALL Report
Steel piping, piping components, and piping elements exposed to steam or treated water (3.4.1-29)	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	No	Flow-Accelerated Corrosion	Consistent with GALL Report
Steel piping, piping components, and piping elements exposed to condensation (internal) or air—outdoor (internal) (3.4.1-30)	Loss of material due to general, pitting, and crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Water Chemistry Control—Primary and Secondary, One-Time Inspection, Periodic Surveillance and Preventive Maintenance	See SER Section 3.4.2.1.6
Steel heat exchanger components exposed to raw water (3.4.1-31)	Loss of material due to general, pitting, crevice, galvanic, and microbiologically influenced corrosion and fouling	Open-Cycle Cooling Water System	No	Service Water Integrity	Not applicable to IP (see SER Section 3.4.2.1.7)
Stainless steel and copper alloy piping, piping components, and piping elements exposed to raw water (3.4.1-32)	Loss of material due to pitting, crevice, and microbiologically influenced corrosion	Open-Cycle Cooling Water System	No	Periodic Surveillance and Preventive Maintenance, and One-Time Inspection	See SER Section 3.4.2.1.8 for IP2. Not applicable to IP3 steam and power conversion systems (see SER Section 3.4.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel heat exchanger components exposed to raw water (3.4.1-33)	Loss of material due to pitting, crevice, and microbiologically influenced corrosion and fouling	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to IP (see SER Section 3.4.2.1.1)
Steel, stainless steel, and copper alloy heat exchanger tubes exposed to raw water (3.4.1-34)	Reduction of heat transfer due to fouling	Open-Cycle Cooling Water System	No	Not applicable	Not applicable to IP (see SER Section 3.4.2.1.1)
Copper alloy > 15% Zn piping, piping components, and piping elements exposed to closed-cycle cooling water, raw water, or treated water (3.4.1-35)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Selective Leaching	Consistent with GALL Report for IP2. Not applicable to IP3 steam and power conversion systems (see SER Section 3.4.2.1.1)
Gray cast-iron piping, piping components, and piping elements exposed to soil, treated water, or raw water (3.4.1-36)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Not applicable	Not applicable to IP (see SER Section 3.4.2.1.1)
Steel, stainless steel, and nickel-based alloy piping, piping components, and piping elements exposed to steam (3.4.1-37)	Loss of material due to pitting and crevice corrosion	Water Chemistry	No	Water Chemistry Control—Primary and Secondary, and One-Time Inspection	Consistent with GALL Report
Steel bolting and external surfaces exposed to air with borated water leakage (3.4.1-38)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	No	Not applicable	Not applicable to IP (see SER Section 3.4.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to steam (3.4.1-39)	SCC	Water Chemistry	No	Water Chemistry Control—Primary and Secondary, and One-Time Inspection	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Glass piping elements exposed to air, lubricating oil, raw water, and treated water (3.4.1-40)	None	None	NA	None	Consistent with GALL Report
Stainless steel, copper alloy, and nickel alloy piping, piping components, and piping elements exposed to air—indoor uncontrolled (external) (3.4.1-41)	None	None	NA	None	Consistent with GALL Report
Steel piping, piping components, and piping elements exposed to air—indoor controlled (external) (3.4.1-42)	None	None	NA	Not applicable	Not applicable to IP (see SER Section 3.4.2.1.1)
Steel and stainless steel piping, piping components, and piping elements in concrete (3.4.1-43)	None	None	NA	Not applicable	Not applicable to IP (see SER Section 3.4.2.1.1)
Steel, stainless steel, aluminum, and copper alloy piping, piping components, and piping elements exposed to gas (3.4.1-44)	None	None	NA	None	Consistent with GALL Report

The staff's review of the steam and power conversion system component groups followed one of several approaches. In one approach, documented in SER Section 3.4.2.1, the staff reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. In the second approach, documented in SER Section 3.4.2.2, the staff reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. In the third approach, documented in SER Sections 3.4A.2.3 (for IP2) and 3.4B.2.3 (for IP3), the staff reviewed AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff documents its review of AMPs credited with managing or monitoring the aging effects for the steam and power conversion system components in SER Section 3.0.3.

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 system components:

- Aboveground Steel Tanks Program
- Bolting Integrity Program
- Buried Piping and Tanks Inspection Program
- External Surfaces Monitoring Program
- Flow-Accelerated Corrosion Program
- Oil Analysis Program
- One-Time Inspection Program
- Periodic Surveillance and Preventive Maintenance Program
- Water Chemistry Control—Primary and Secondary Program

LRA Tables 3.4.2-1-IP2 through 3.4.2-4-IP2 and 3.4.2-1-IP3 through 3.4.2-4-IP3 summarize the results of AMRs for the steam and power conversion system components and indicate AMRs claimed to be consistent with the GALL Report.

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

For each AMR line item, the applicant stated how the information in the tables aligns with the information in the GALL Report. Notes A through E indicate how the AMR is consistent with the GALL Report. The staff audited these AMRs.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report and determined that the identified exceptions to the GALL Report AMPs had been reviewed and accepted. The staff also determined whether the applicant's AMP was consistent with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item is consistent with, although different from, the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report; however, the applicant identified a different component in the GALL Report with the same material, environment, aging effect, and AMP as the component under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item is consistent with, although different from, 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 line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review and whether the identified exceptions to the GALL Report AMPs had been reviewed and accepted. The staff also determined whether the applicant's AMP was consistent with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but credits a different AMP. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the credited AMP would manage the aging effect consistently with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

The staff audited and reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluation follows.

3.4.2.1.1 AMR Results Identified as Not Applicable

In LRA Table 3.4.1, the applicant identified Items 21, 23, 25 (IP3), 26 (IP3), 27, 31, 32 (IP3), 33, 34, 35 (IP3), 36, 38, 42, and 43 as not applicable, since the combination of component, material, and environment does not apply to the in-scope components. For each of these items, the staff reviewed the LRA and the applicant's supporting documents and confirmed the applicant's claim that the combination of component, material, and environment does not exist. On the basis that IP2 and IP3 do not have the combination of component, material, and environment, the staff finds that these AMRs are not applicable to IP.

For IP3, the staff noted that there are no items in Tables 3.4.2 and 3.3.2-19 in the IP3 steam and power conversion system that reference Items 3.4.1-25, 3.4.1-26, 3.4.1-32, and 3.4.1-35 of Table 3.4.1. On the basis that IP3 does not have any components from this group, the staff finds that the aging effect covered by these items is not applicable to the IP3 steam and power conversion system.

3.4.2.1.2 Steel Bolting and Closure Bolting Exposed to Air—with Steam or Water Leakage, Air—Outdoor (external), or Air—Indoor Uncontrolled

In the discussion column of LRA Table 3.4.1, Item 3.4.1-22, the applicant stated that the loss of preload is a design-driven effect and not an aging effect requiring management. This statement appeared to be contrary to the GALL Report recommendation which states that loss of preload is an aging effect. During the audit, the staff asked the applicant to justify why other aging effects were not applicable and why the Bolting Integrity Program (B.1.2) did not take exception to the GALL Report since, at IP, the loss of preload is not considered an aging effect (Audit Item 241).

In its response, dated December 18, 2007, the applicant stated that:

> The reason why loss of preload is not identified as an aging effect is that Entergy has consistently followed industry guidance (EPRI Report 1010639) in performing aging management reviews. Based on these reviews, loss of preload has not been listed as an aging effect requiring management in the system level aging management review results. While not included in system-level aging management review results, loss of preload is addressed in the Bolting Integrity Program for all bolting within the scope of license renewal except for the reactor vessel closure studs, which are addressed in a separate program. The Bolting Integrity Program is an existing program that addresses loss of preload in accordance with the guidelines of NUREG-1801 Section XI.M18, Bolting Integrity.
>
> The program description of LRA Section B.1.2 states that the program applies to all bolting except the reactor head closure studs and includes preventive measures to preclude or minimize loss of preload and cracking. Likewise, loss of material is not an aging effect requiring management for this bolting, but it is also managed by the Bolting Integrity Program. As stated in LRA Section B.1.2, the IP Bolting Integrity Program will be consistent with NUREG-1801 Section XI.M18, which includes measures to manage loss of material and loss of preload. The Bolting Integrity Program will apply to all pressure boundary bolting, including the main steam bolting.
>
> LRA Table 3.4.1, Item 3.4.1-22 discussion column will be clarified by inserting the following sentence after "Improper bolting application (design) and maintenance issues are current plant operational concerns and not related to aging effects or mechanisms that require management during the period of extended operation.
>
> Nevertheless, the Bolting Integrity Program manages loss of preload for all bolting in steam and power conversion systems.

The staff finds the applicant’s response acceptable, because the Bolting Integrity Program includes preventive measures that preclude or minimize the loss of preload. This is consistent with the GALL Report. The applicant provided a clarification for this issue in a letter dated December 18, 2007, and amended the LRA by inserting a sentence stating that the Bolting Integrity Program manages loss of preload. In addition, Commitment 2 has been clarified to specifically state that the Bolting Integrity Program manages the loss of preload and loss of material for all external bolting.

The staff evaluated the applicant’s claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant’s consideration of recent operating experience and proposals for managing aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with its AMRs. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed, so that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.1.3 Steel Heat Exchanger Components Exposed to Closed-Cycle Cooling Water

In the discussion column of LRA Table 3.4.1, Item 3.4.1-24, the applicant claimed consistency with the GALL Report in managing the loss of material by the Water Chemistry Control—Closed Cooling Water Program for steel heat exchanger components exposed to closed-cycle cooling water. However, in LRA Table 3.3.2-19-15-IP2, Item 3.4.1-24 of Table 3.4.1 has been used to manage the loss-of-material aging effect for carbon steel piping, piping components (filter housing, pump casing, valve body, sight glass, and thermowell), tanks, and heat exchanger shells exposed to treated water by using the Water Chemistry Control—Auxiliary Systems Program (B.1.39). The only AMR line item using Item 3.4.1-24 of Table 3.4.1 in the IP3 steam and power conversion systems is for the carbon steel heat exchanger shell exposed to treated water, and it is included in LRA Table 3.3.2-19-23-IP3. This AMR line proposes the use of Water Chemistry Control—Closed Cooling Water Program (B.1.40) to manage the loss-of-material aging effect. These AMR result lines refer to Note E for all these components.

The staff reviewed the above-stated AMR result lines referring to Note E and determined that the component material, environment, and aging effect are consistent with or identical to those of the corresponding line item in the GALL Report. The staff documents its review and evaluation of the applicant's Water Chemistry Control—Auxiliary Systems Program, proposed in the LRA, in SER Section 3.0.3.3.8. SER Section 3.0.3.2.16 documents the staff's review and evaluation of the applicant's Water Chemistry Control—Closed Cooling Water Program, proposed in the LRA. The staff finds that this program includes activities that control water chemistry and are consistent with the recommendations in the GALL Report. The staff finds that these programs include activities that control water chemistry, are consistent with the recommendations in the GALL Report, and are adequate to manage the loss of material in the above-stated carbon steel components exposed to treated water.

The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with its AMRs. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed, so that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.1.4 Stainless Steel Piping, Piping Components, Piping Elements, and Heat Exchanger Components Exposed to Closed-Cycle Cooling Water

In the discussion column of LRA Table 3.4.1, Item 3.4.1-25, the applicant claimed consistency with the GALL Report in managing the loss of material by using the Water Chemistry Control—Closed Cooling Water Program for stainless steel piping, piping components, piping elements, and heat exchanger components exposed to closed-cycle cooling water. However, in LRA Table 3.3.2-19-15-IP2, Item 3.4.1-25 of Table 3.4.1 has been used to manage the loss-of-material aging effect for stainless steel piping and stainless steel piping components, such as strainer housing and valve bodies, exposed to treated water by using the Water Chemistry Control—Auxiliary Systems Program (B.1.39). These AMR result lines refer to Note E for all these components.

The staff reviewed the above-stated IP2 AMR result lines referring to Note E and determined that the component material, environment, and aging effect are consistent with or identical to those of the corresponding line item in the GALL Report. The staff documents its review and evaluation of the applicant's Water Chemistry Control—Auxiliary Systems Program, proposed in the LRA, in SER Section 3.0.3.3.8. The staff finds that this program includes activities that control water chemistry, are consistent with the recommendations in the GALL Report, and are adequate to manage the loss of material in the above-stated carbon steel components exposed to treated water.

The staff evaluated the applicant's claim of consistency with the GALL Report for IP2. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with its AMRs. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed, so that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

For IP3, none of the AMR line items in LRA Tables 3.4.2-1-IP3 through 3.4.2-4-IP3, or any of the Table 3.3.2-19-XX-IP3 in the steam and power conversion systems used Table 3.4-1 Item 3.4.1-25. Therefore, the above combination of material, environment, and AERM does not apply to IP3.

3.4.2.1.5 Copper Alloy Piping, Piping Components, and Piping Elements Exposed to Closed-Cycle Cooling Water

In the discussion column of LRA Table 3.4.1, Item 3.4.1-26, the applicant claimed consistency with the GALL Report in managing the loss of material by using the Water Chemistry Control—Closed Cooling Water Program for copper alloy piping, piping components, and piping elements exposed to closed-cycle cooling water. However, in LRA Table 3.3.2-19-15-IP2, Item 3.4.1-26 of Table 3.4.1 has been used to manage the loss-of-material aging effect for a copper alloy valve body exposed to treated water by using the Water Chemistry Control—Auxiliary Systems Program (B.1.39). This AMR result line refers to Note E for this component.

The staff reviewed the above-stated IP2 AMR result line referring to Note E and determined that the component material, environment, and aging effect are consistent with or identical to those of the corresponding line item in the GALL Report. The staff documents its review and evaluation of the applicant's Water Chemistry Control—Auxiliary Systems Program, proposed in the LRA, in SER Section 3.0.3.3.8. The staff finds that this program includes activities that control water chemistry, are consistent with the recommendations in the GALL Report, and are adequate to manage the loss of material in the above-stated carbon steel component exposed to treated water.

The staff evaluated the applicant's claim of consistency with the GALL Report for IP2. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with its AMRs. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed, so that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

For IP3, none of the AMR line items in LRA Tables 3.4.2-1-IP3 through 3.4.2-4-IP3, or any of the Table 3.3.2-19-XX-IP3 in the steam and power conversion systems used Item 3.4.1-26 of Table 3.4.1. Therefore, the above combination of material, environment, and AERM does not apply to IP3.

3.4.2.1.6 Steel Piping, Piping Components, and Piping Elements Exposed to Outdoor Air (Internal) or Condensation (Internal)

In the discussion column of LRA Table 3.4.1, Item 3.4.1-30, the applicant stated that "steel components with intended functions in steam and power conversion systems with the internal surface exposed to outdoor air or condensation are the condensate storage tanks (CSTs), steel main steam safety valve tailpipes, and atmospheric dump valve silencers. The condensate storage tank vapor space is nitrogen blanketed but the environment is conservatively assumed to be condensation." Even though Item 3.4.1-30 of Table 3.4.1 does not cover steel tanks, this item has been used in LRA Tables 3.4.2-3-IP2 and 3.4.2-3-IP3 for managing the loss of material due to general, pitting, and crevice corrosion by using the Water Chemistry Control—Primary and Secondary Program (B.1.41) and the One-Time Inspection Program (B.1.27) for the steel condensate storage tank exposed to condensation. This AMR result line refers to Note E for this component.

The staff reviewed the above-stated AMR result line referring to Note E and determined that the component material, environment, and aging effect are consistent with or identical to those of the corresponding line item in the GALL Report. The staff documents its reviews and evaluations of the applicant's Water Chemistry Control—Primary and Secondary Program and its One-Time Inspection Program, proposed in the LRA, in SER Sections 3.0.3.2.17 and 3.0.3.1.9, respectively. The staff finds that the use of the Water Chemistry Control—Primary and Secondary Program to control water chemistry and the use of the One-Time Inspection Program to verify the effectiveness of chemistry controls are consistent with the recommendations in the GALL Report and are adequate to manage the loss of material in the steel condensate storage tank exposed to condensation.

The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with its AMRs. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed, so that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.1.7 Steel Heat Exchanger Components Exposed to Raw Water

In the discussion column of LRA Table 3.4.1, Item 3.4.1-31, the applicant stated that this item is not applicable to IP. The discussion column also notes that there are no steel heat exchanger components with intended functions exposed to raw water in the steam and water conversion system. However, LRA Tables 3.3.2-19-23-IP2 and 3.3.2-19-23-IP3 do use Item 3.4.1-31 of Table 3.4.1 to manage the loss of material for a steel heat exchanger shell exposed to raw water (internal). The LRA uses the Service Water Integrity Program (B.1.34) to manage the aging effect for this component. The AMR result line refers to Note C for this component, indicating that the component is consistent with the GALL Report for material, environment, and aging effect and that the AMP used for aging management is also consistent with the GALL Report.

The staff reviewed the above-stated AMR result line and determined that the use of the Service Water Integrity Program (B.1.34) for managing the loss-of-material aging effect for a steel heat exchanger shell exposed to raw water (internal) is consistent with the GALL Report, Table 4, Line Item 31. The staff documents its review and evaluation of the applicant's Service Water Integrity Program in SER Section 3.0.3.1.14.

3.4.2.1.8 Stainless Steel and Copper Alloy Piping, Piping Components, and Piping Elements Exposed to Raw Water

In LRA Table 3.3.2-19-6-IP2, the applicant used Item 3.4.1-32 of Table 3.4.1 to manage the loss-of-material aging effect for (1) stainless steel tubing exposed to raw water (internal) by using the One-Time Inspection Program (B.1.27), (2) copper alloy valve body exposed to raw water (internal) by using the Periodic Surveillance and Preventive Maintenance Program (B.1.29), and (3) stainless steel valve body exposed to raw water (internal) by using the One-Time Inspection Program (B.1.27). The GALL Report recommends Open-Cycle Cooling Water System Program AMP XI.M20 for this AERM. The AMR result lines for these three components in LRA Table 3.3.2-19-6-IP2 refer to Note E, indicating that different AMPs are credited for these components.

By letter dated June 12, 2009, the applicant amended its LRA to state that stainless steel pump casings exposed internally and externally to raw water with an aging effect of loss of material will be managed by the Periodic Surveillance and Preventive Maintenance Program, and referenced Item 3.4.1-32 of LRA Table 3.4-1.

The use of the Periodic Surveillance and Preventive Maintenance Program for managing the loss-of-material aging effect for stainless steel pump casings exposed to raw water (internal and external) and copper alloy valve bodies exposed to raw water (internal) is adequate because this program includes activities that are consistent with the recommendations in the GALL Report. The component material, environment, and aging effect are also consistent with or identical to those of the corresponding line items in the GALL Report. The staff's review and evaluation of the applicant's Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.3.7.

The use of the One-Time Inspection Program for managing the loss-of-material aging effect for stainless steel tubing and valve body exposed to raw water (internal) is adequate because the One-Time Inspection Program manages this aging effect by visual and other NDE techniques to verify that the loss of material has not occurred or is so insignificant that no AMP is warranted for this component. The staff's review of the One-Time Inspection Program is documented in SER Section 3.0.3.1.9.

The staff evaluated the applicant's claim of consistency with the GALL Report for IP2. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent with the GALL Report AMRs. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed, so that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

For IP3, none of the AMR line items in LRA Tables 3.4.2-1-IP3 through 3.4.2-4-IP3, or any of the Table 3.3.2-19-XX-IP3 in the steam and power conversion systems used Item 3.4.1-32 of Table 3.4.1. Therefore, the above combination of material, environment, and AERM does not apply to IP3.

3.4.2.1.9 IP2 Auxiliary Feedwater Pump Room Fire Event

In LRA Section 3.4.2, the applicant summarizes its AMR results for the IP2 auxiliary feedwater pump room fire event. In the LRA, the applicant states that

> The components in the systems required to supply feedwater to the steam generators during the short duration of the fire event are in service at the time the event occurs or their availability is checked daily. Therefore, integrity of the systems and components required to perform post-fire intended functions for at least one hour is continuously confirmed by normal plant operation. During the event these systems and components must continue to perform their intended functions to supply feedwater to the steam generators for a minimum of one hour. Significant degradation that could threaten the performance of the intended functions will be apparent in the period immediately preceding the event and corrective action will be required to sustain continued operation. For the minimal one hour period that these systems would be required to provide make up to the steam generators, further aging degradation that would not have been apparent prior to the event is negligible. Therefore, no aging effects are identified, and no Summary of Aging Management Review table is provided.

Section 54.21(a)(1) of 10 CFR requires that for those systems, structures, and components within the scope of license renewal, as delineated in § 54.4, applicants must identify and list those structures and components subject to an aging management review. Additionally, Section 54.21(a)(3), requires that for each structure and component identified in paragraph 54.21(a)(1), applicants must demonstrate 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. Based on the information contained in the LRA, Entergy does not appear to have demonstrated that the effects of aging for passive, long-lived components within the systems credited for providing flow to the steam generators during the fire event will be adequately managed.

By letter dated December 30, 2008, the staff issued an RAI to request that the applicant provide a list of passive, long-lived component types, material, environment, and aging effect combinations, and the programs that will be used to manage the aging effects for these SCs. Pending receipt and review of the applicant’s response, this was identified as Open Item 3.4-1.

By letter dated January 27. 2009, Entergy responded to the staff’s request. Entergy reiterated that as indicated in LRA Section 2.3.4.5, normal plant operation demonstrates the ability of secondary systems to supply feedwater to the steam generators. Additionally, it stated that the function of supporting safe shutdown in the event of a fire in the auxiliary feed pump room is confirmed on an ongoing basis since the required SSCs are performing their intended functions under design basis conditions during normal operation. Furthermore, performance of intended functions during normal plant operation demonstrates that the systems and components can perform those functions for one hour in the event of a fire in the auxiliary feedwater pump room.

Additionally, Entergy provided tables containing clarifying details regarding the passive, long-lived component types, materials, environments, aging effects and programs for SSCs that support the AFW pump room fire event that were not already included in scope and subject to an AMR for 10CFR54.4(a)(1) or (a)(2). For each entry in the provided tables, Entergy listed the aging effect as “none,” and the AMP as “none,” and provided plant-specific note 408 which states:

> Materials and environments have been identified, however there are no aging effects requiring management. The function of supporting safe shutdown in the event of a fire in the auxiliary feed pump room is confirmed since these SSCs, which are required to support this function, perform their intended functions during normal operation. Conditions under which these SSCs must perform their intended functions are the same conditions under which they operate during the course of normal plant operations. Performance of intended functions during normal plant operation demonstrates that the systems and components can perform those functions for one hour in the event of a fire in the auxiliary feedwater pump room.

The staff reviewed the applicant’s response and determined that the systems contain passive, long-lived components made of materials that when exposed to the stated environments may experience aging effects as described in the GALL Report, which must be managed during the period of extended operation in accordance with 10 CFR 54.21(a)(3).

By letter dated May 1, 2009, Entergy submitted a clarification response to RAI 3.4.2-1 as well as a new commitment (Commitment 39) to install a fixed automatic fire suppression system for IP2 in the AFW pump room prior to entering the period of extended operation. Entergy stated that this commitment will delete the requirement for IP2 to place reliance on certain portions of the secondary plant systems for alternate secondary heat sink measures to cope with potential AFW Pump Room fire scenarios. In addition, it stated that all of the tables that were provided in the January 27, 2009 letter are superseded by this commitment.

The staff determined that because the planned installation is not yet part of the CLB, it cannot make a finding consistent with the requirement in 10 CFR 54.29(a). Therefore, by letter dated May 20, 2009, the staff requested that the applicant provide information to demonstrate that the effects of aging will be adequately managed so that the intended function(s) will maintained consistent with the current licensing basis for the period of extended operation as required by 10 CFR 54.21(a)(3). Specifically, the staff requested that the applicant list all aging effects and the aging management programs needed to manage the aging effects for the component types provided in the January 27, 2009 letter.

By letter dated June 12, 2009, the applicant responded to the staff’s May 20, 2009 request and provided revised tables which include aging effects and aging management programs to manage the aging effects for the component types that support the AFW pump room fire event that were not already included in scope and subject to aging management review for 10 CFR 54.4(a)(1) or (a)(2).

The applicant revised LRA Tables 3.4.2-5-1-IP2 through 3.4.2-5-13-IP2 to include aging effects and AMPs for all of the components previously identified in response to RAI 3.4.2-1 by letter dated January 27, 2009. The staff reviewed the applicant's revised AMR results and found that the AMR results are consistent with the GALL Report for these combinations of materials and environments with Notes A through D. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

The staff's evaluation of AMR results with Note E is documented in SER Sections 3.3.2.1.3, 3.3.2.1.5, 3.3.2.1.9, 3.3.2.1.10, 3.3.2.2.10, 3.4.2.1.8, and 3.4.2.2.3. The staff's evaluation of AMR results not consistent with or not addressed in the GALL Report is documented in SER Section 3.4A.2.3.5.

Based upon the applicant's provision of the revised AMR results identifying appropriate aging effects and AMPs, and the staff's review thereof, Open Item 3.4-1 is closed.

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 evaluated aging management for the steam and power conversion system components, as recommended by the GALL Report, and provided information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to general, pitting, and crevice corrosion
- loss of material due to general, pitting, crevice, and microbiologically influenced corrosion and fouling
- reduction of heat transfer due to fouling
- loss of material due to general, pitting, crevice, and microbiologically influenced corrosion
- SCC
- loss of material due to pitting and crevice corrosion
- loss of material due to pitting, crevice, and microbiologically influenced corrosion
- loss of material due to general, pitting, crevice, and galvanic corrosion
- QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the report and for which the report recommends further evaluation, the staff audited and reviewed the applicant's evaluation to determine whether it adequately addressed the issues. 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 evaluations follows.

3.4.2.2.1 Cumulative Fatigue Damage

LRA Section 3.4.2.2.1 states that fatigue is a TLAA, as defined in 10 CFR 54.3. Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(c)(1).

The applicant stated that Section 4.3 of the LRA addresses those steam and power conversion system components that require metal fatigue analysis. The staff verified that LRA Table 3.4.1 includes an applicable line item on metal fatigue of steam and power conversion system components, as stated in LRA AMR Item 3.4.1-1, and that LRA Section 4.3.2 contains the section on TLAA and metal fatigue analysis for steam and power conversion system components. The staff also reviewed the applicant's further evaluation assessment in LRA Section 3.4.2.2.1 to verify that it conforms to the recommendations provided in SRP-LR Section 3.4.2.2.1 and that the LRA includes AMR Item 3.4.1-1, which corresponds to this further evaluation item. The staff also verified that AMR Item 3.4.1-1 is consistent with and conforms to the recommended AMR evaluation in AMR Item 1 in Table 4 of the GALL Report. Based on this review, the staff concludes that the applicant's further evaluation discussion in LRA Section 3.4.2.2.1 is consistent with and conforms to the evaluation recommendations in SRP-LR Section 3.4.2.2.1 and is acceptable. The staff also concludes that the LRA includes AMR Item 3.4.1-1 on metal fatigue for applicable steam and power conversion system components and that this AMR is consistent with the recommendations in Table 4 of the GALL Report.

The staff reviewed the applicant's TLAA on metal fatigue, and SER Section 4.3 and its subsections contain its evaluation.

By letter dated March 24, 2008, the applicant amended its LRA Tables 3.3.2-19-12-IP2, 3.3.2-19-2-IP3, 3.3.2-19-14-IP3 and 3.3.2-19-27-IP3 to state the Periodic Surveillance and Preventive Maintenance Program will provide aging management of carbon steel sight glasses in either a treated water (internal) or steam (internal) environment for the aging effect of cracking due to fatigue.

By letter dated June 11, 2008, the applicant amended its LRA Table 3.3.2-19-27-IP3 to state the Periodic Surveillance and Preventive Maintenance Program will provide aging management of carbon steel sight glasses in a treated water (internal) environment for the aging effect of cracking due to fatigue.

The staff's review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.3.7. The Periodic Surveillance and Preventive Maintenance Program enhancements add new activities to the plant's preventive maintenance and surveillance programs, which implement preventive maintenance and surveillance testing activities through repetitive tasks or routine monitoring of plant operations. The staff also determined that this program will use visual or other NDE techniques to inspect a representative sample of components to manage cracking due to fatigue. On the basis of its review, the staff finds that because these components will be inspected periodically for loss of material and fouling, the aging effect for these component/environment combinations will be effectively managed by this aging management program.

3.4.2.2.2 Loss of Material Due to General, Pitting, and Crevice Corrosion

The staff reviewed LRA Section 3.4.2.2.2 against the criteria in SRP-LR Section 3.4.3.2.2.

(1) LRA Section 3.4.2.2.2 addresses the loss of material due to general, pitting, and crevice corrosion for carbon steel piping and piping components, heat exchanger components, and tanks exposed to treated water and for carbon steel piping and components exposed to steam in the steam and power conversion and other systems, stating that the Water Chemistry Control—Primary and Secondary Program manages this aging effect. The One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control—Primary and Secondary Program by an inspection of a representative sample of components that credit it, including those in areas of stagnant flow and other susceptible locations.

SRP-LR Section 3.4.2.2.2 states that the loss of material due to general, pitting, and crevice corrosion may occur in steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated water and in steel piping, piping components, and piping elements exposed to steam. The existing AMP monitors and controls water chemistry to manage the effects of the loss of material due to general, pitting, and crevice corrosion. However, control of water chemistry does not preclude the loss of material due to general, pitting, and crevice corrosion at locations with stagnant flow conditions; therefore, the effectiveness of water chemistry control programs should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to verify the effectiveness of water chemistry control programs. A one-time inspection of selected components and susceptible locations is an acceptable method to ensure that corrosion does not occur and that the intended functions of components will be maintained during the period of extended operation.

SRP-LR Item 3.4.2.2.2, Item 1, cites Items 2, 3, 4, and 6 in Table 4 of the GALL Report. Collectively, AMR Items 2, 3, 4, and 6 in Table 4 of the GALL Report reference generic AMR items that may be applicable to the steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to a treated water environment, and to the steel piping, piping components, and piping elements exposed to a steam environment in PWR steam and power conversion systems. For these combinations of components, material, and environment, the GALL Report (like the SRP-LR) recommends that the Water Chemistry Control—Primary and Secondary Program be credited with preventing or mitigating the loss of material in the components and that a plant-specific program be credited with verifying the effectiveness of the Water Chemistry Control—Primary and Secondary Program in achieving its preventive or mitigative function. Like the SRP-LR, the GALL AMRs identify the One-Time Inspection Program as an acceptable program to verify the effectiveness of the applicant’s Water Chemistry Control—Primary and Secondary Program.

The staff noted that the applicant had not included the steam turbine system and the extraction steam system in the list of systems covered under the steam and power conversion systems described in LRA Section 3.4.1. In response to Audit Item 234, by letter dated December 18, 2007, the applicant explained that, for IP2, the steam turbine system was listed as the turbine generator system and the extraction steam system was included in the main steam system.

Items 3.4.1-2 and 3.4.1-4 in LRA Table 3.4.1 address the loss of material due to general, pitting, and crevice corrosion for steel piping, piping components, and piping elements exposed to steam or treated water. During the audit, the staff confirmed that the applicant uses the Water Chemistry Control—Primary and Secondary Program to manage aging effects and verifies the effectiveness of its water chemistry controls through the One-Time Inspection Program. This program includes inspections of selected components at susceptible locations, as recommended by the GALL Report. The One-Time Inspection Program is a new program that, when implemented, will be consistent with GALL AMP XI.M32. The staff reviewed and evaluated the applicant's Water Chemistry Control—Primary and Secondary Program and the One-Time Inspection Program and documents its evaluations in Sections 3.0.3.2.17 and 3.0.3.1.9, respectively. Based on the programs identified above, the staff concludes that the applicant has met the criteria in SRP-LR Section 3.4.2.2.2(1) for further evaluation.

LRA Table 3.4.1, Item 3.4.1-3, addresses the loss of material due to general, pitting, and crevice corrosion for steel heat exchanger components exposed to treated water. During the audit, the staff confirmed that the applicant uses the Water Chemistry Control—Primary and Secondary Program to manage aging effects and verifies the effectiveness of its water chemistry controls through the One-Time Inspection Program. This program includes inspections of selected components at susceptible locations, as recommended by the GALL Report. The One-Time Inspection Program is a new program that, when implemented, will be consistent with GALL AMP XI.M32. The staff reviewed and evaluated the applicant's Water Chemistry Control—Primary and Secondary Program and the One-Time Inspection Program and documents its evaluations in Sections 3.0.3.2.17 and 3.0.3.1.9, respectively. Based on the programs identified above, the staff concludes that the applicant has met the criteria in SRP-LR Section 3.4.2.2.2(1) for further evaluation.

LRA Table 3.4.1, Item 3.4.1-6, addresses the loss of material due to general, pitting, and crevice corrosion for steel and stainless steel tanks exposed to treated water. During the audit, the staff confirmed that the applicant uses the Water Chemistry Control—Primary and Secondary Program to manage aging effects and verifies the effectiveness of water chemistry controls through the One-Time Inspection Program. This program includes inspections of selected components at susceptible locations, as recommended by the GALL Report. The One-Time Inspection Program is a new program that, when implemented, will be consistent with GALL AMP XI.M32. The staff reviewed and evaluated the applicant's Water Chemistry Control—Primary and Secondary Program and the One-Time Inspection Program and documents its evaluations in Sections 3.0.3.2.17 and 3.0.3.1.9, respectively. Based on the programs identified above, the staff concludes that the applicant has met the criteria in SRP-LR Section 3.4.2.2.2(1) for further evaluation.

(2) LRA Section 3.4.2.2.2 addresses the loss of material due to general, pitting, and crevice corrosion in steel piping and components exposed to lubricating oil, stating that the Oil Analysis Program manages this aging effect by periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits and preserve an environment not conducive to corrosion. The One-Time Inspection Program will use visual inspections or NDEs of representative samples to confirm the effectiveness of the Oil Analysis Program in managing aging effects for components that credit it.

SRP-LR Section 3.4.2.2.2 states that the loss of material due to general, pitting, and crevice corrosion may occur in steel piping, piping components, and piping elements exposed to lubricating oil. The existing AMP periodically samples and analyzes lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment not conducive to corrosion. However, control of lubricating oil contaminants may not always be fully effective in precluding corrosion; therefore, the applicant should verify the effectiveness of its lubricating oil contaminant controls to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of lubricating oil chemistry control programs. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that the intended functions of components will be maintained during the period of extended operation.

LRA Table 3.4.1, Item 3.4.1-7, addresses the loss of material due to general, pitting, and crevice corrosion for steel piping, piping components, and piping elements exposed to lubricating oil. During the audit, the staff confirmed that the applicant uses the Oil Analysis Program to manage the loss-of-material aging effect and verifies the effectiveness of the lubricating oil chemistry control using the One-Time Inspection Program. This program inspects selected components at susceptible locations, as recommended by the GALL Report. The staff reviewed and evaluated the applicant's Oil Analysis Program, which maintains lubricating oil contaminants within acceptable limits. Monitoring and trending the results of lubricating oil analyses can identify the aging of components before their intended functions are lost. The staff also reviewed the One-Time Inspection Program, which is a new program that, when implemented, will be consistent with GALL AMP XI.M32. The staff documents its review and evaluation of the Oil Analysis Program and the One-Time Inspection Program in Sections 3.0.3.2.12 and 3.0.3.1.9, respectively. Based on the programs identified above, the staff concludes that the applicant has met the criteria in SRP-LR Section 3.4.2.2.2(2) for further evaluation.

In the "Notes" column of LRA Tables 3.3.2-19-15-IP2 and 3.3.2-19-15-IP3, the applicant has included Footnote D for several lines addressing steel piping, piping components, and steel tank items. The applicant used Item 3.4.1-7 of LRA Table 3.4.1 to manage the loss-of-material aging effect for the items in Footnote D. All these steel components are exposed to a lubricating oil environment. The applicant has proposed managing loss-of-material AERMs for these components by using the Oil Analysis Program, together with the One-Time Inspection Program, which will verify the effectiveness of the Oil Analysis Program. Based on the review of the combination of material, environment, AERMs, and AMPs, the staff finds the proposed programs acceptable for these components. The same combination of material, environment, AERMs, and AMPs is recommended in the GALL Report for steel components, such as piping, piping components, and piping elements, exposed to lubricating oil.

Based on the programs identified above, the staff concludes that the applicant's programs meet the criteria in SRP-LR Section 3.4.2.2.2. For those line items that apply to LRA Section 3.4.2.2.2, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed, so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.3 Loss of Material Due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion and Fouling

The staff reviewed LRA Section 3.4.2.2.3 against the criteria in SRP-LR Section 3.4.3.2.3.

LRA Section 3.4.2.2.3 addresses the loss of material due to general, pitting, crevice, and microbiologically influenced corrosion and fouling in steel piping and components in the steam and power conversion systems exposed to raw water, stating that the Periodic Surveillance and Preventive Maintenance Program manages this aging effect by visual inspections and other NDE techniques so the intended functions of components will not be affected.

SRP-LR Section 3.4.2.2.3 states that the loss of material due to general, pitting, crevice, and microbiologically influenced corrosion and fouling may occur in steel piping, piping components, and piping elements exposed to raw water. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that the aging effect is adequately managed.

By letter dated June 12, 2009, the applicant amended LRA Table 3.4.2-5-3-IP2 to state that carbon steel bolting, piping, pump casing (internal and external surface) and gray cast iron pump casings (internal and external surface) exposed either internally or externally to raw water will be managed by the Periodic Surveillance and Preventive Maintenance Program.

The applicant has used Item 3.4.1-8 of LRA Table 3.4.1 to manage the loss of material due to general, pitting, crevice, and microbiologically influenced corrosion and fouling in the circulating water system's carbon steel piping and piping components exposed to a raw water environment. To manage this aging effect, the applicant has proposed using the Periodic Surveillance and Preventive Maintenance Program (B.1.29), which is an existing plant-specific program. During the site audit, the staff reviewed details of this program, along with the pertinent plant records documenting the use of this program. The staff also reviewed the applicable procedures for analyzing the results obtained from periodic surveillance and inspections during preventive maintenance activities, as well as those for handling and controlling corrective actions. The program uses visual inspections and NDE techniques to manage the loss of material. The staff documents its review and evaluation of this program in Section 3.0.3.3.7. In the "Notes" column of LRA Tables 3.3.2-19-6-IP2 and 3.3.2-19-12-IP3, the applicant has referenced Note E for the components for which Item 3.4.1-8 of Table 3.4.1 has been used. Based on the review of the applicant's program and the supporting plant documentation depicting the use of the program, the staff finds the proposed program acceptable for these components.

Based on the program identified above, the staff concludes that the applicant's program meets the criteria in SRP-LR Section 3.4.2.2.3. For those line items that apply to LRA Section 3.4.2.2.3, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed, so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.4 Reduction of Heat Transfer Due to Fouling

The staff reviewed LRA Section 3.4.2.2.4 against the criteria in SRP-LR Section 3.4.3.2.4.

(1) LRA Section 3.4.2.2.4 addresses the reduction of heat transfer due to fouling for stainless steel and copper alloy heat exchanger tubes exposed to treated water, stating that the Water Chemistry Control—Primary and Secondary Program manages this aging effect. The One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control—Primary and Secondary Program by an inspection of a representative sample of components that credit it, including those in areas of stagnant flow and other susceptible locations. The steam and power conversion systems have no stainless steel heat exchanger tubes with intended functions exposed to treated water.

SRP-LR Section 3.4.2.2.4 states that the reduction of heat transfer due to fouling may occur in stainless steel and copper alloy heat exchanger tubes exposed to treated water. The existing AMP controls water chemistry to manage the reduction of heat transfer due to fouling. However, the control of water chemistry may not always be fully effective in precluding fouling. Therefore, the GALL Report recommends that the effectiveness of water chemistry control programs be verified to ensure that the reduction of heat transfer due to fouling does not occur. A one-time inspection is an acceptable method to ensure that the reduction of heat transfer does not occur and that the intended functions of components will be maintained during the period of extended operation.

LRA Table 3.4.1, Item 3.4.1-9, addresses the reduction of heat transfer due to fouling in stainless steel and copper alloy heat exchanger tubes exposed to treated water. The only AMR item that uses Item 3.4.1-9 of LRA Table 3.4.1 covers copper heat exchanger tubes exposed to treated water and is included in LRA Tables 3.4.2-3-IP2 and 3.4.2-3-IP3. These heat exchanger tubes are part of the AFW system. IP does not have any in-scope stainless steel heat exchanger tubes in the steam and power conversion systems.

During the site audit, the staff confirmed that the applicant uses the Water Chemistry Control—Primary and Secondary Program to manage aging effects and verifies the effectiveness of water chemistry control by the One-Time Inspection Program. The One-Time Inspection Program includes an inspection of selected components at susceptible locations, as recommended by the GALL Report. The One-Time Inspection Program is a new program that, when implemented, will be consistent with GALL AMP XI.M32. The staff documents its review and evaluation of the applicant's Water Chemistry Control—Primary and Secondary Program and its One-Time Inspection Program in SER Sections 3.0.3.2.17 and 3.0.3.1.9, respectively. Based on the programs identified above, the staff concludes that the applicant has met the criteria in SRP-LR Section 3.4.2.2.2(1) for further evaluation.

(2) LRA Section 3.4.2.2.4 addresses the reduction of heat transfer due to fouling for copper alloy heat exchanger tubes exposed to lubricating oil in steam and power conversion systems, stating that the Oil Analysis Program manages this aging effect. There are no stainless steel or steel heat exchanger tubes exposed to lubricating oil in the steam and power conversion systems that have the intended function of transferring heat. This program periodically samples and analyzes lubricating oil to maintain contaminants within acceptable limits and preserve an environment not conducive to fouling. The One-

Time Inspection Program will use visual inspections or NDEs of representative samples to confirm the effectiveness of the Oil Analysis Program in managing aging effects for components that credit it.

SRP-LR Section 3.4.2.2.4 states that the reduction of heat transfer due to fouling may occur in steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil. The existing AMP monitors and controls lubricating oil chemistry to mitigate the reduction of heat transfer due to fouling. However, controlling lubricating oil chemistry may not always be fully effective in precluding corrosion; therefore, the applicant should verify the effectiveness of its lubricating oil contaminant controls to ensure that fouling does not occur. The GALL Report recommends further evaluation of the effectiveness of programs to control lubricating oil chemistry. A one-time inspection of selected components at susceptible locations is an acceptable method to determine whether an aging effect is occurring or is slowly progressing, to ensure that the components' intended functions will be maintained during the period of extended operation.

LRA Table 3.4.1, Item 3.4.1-10, addresses the reduction of heat transfer due to fouling in steel, stainless steel, and copper alloy heat exchanger tubes exposed to lubricating oil. The only AMR item that uses Item 3.4.1-10 of LRA Table 3.4.1 covers copper heat exchanger tubes exposed to lubricating oil and is included in LRA Table 3.4.2-3-IP2. These heat exchanger tubes are part of the AFW system. IP2 does not have any in-scope stainless steel heat exchanger tubes in the steam and power conversion systems.

During the site audit, the staff confirmed that the applicant uses the Oil Analysis Program to manage the aging effect and verifies the effectiveness of this program through the One-Time Inspection Program, which includes an inspection of selected components at susceptible locations, as recommended by the GALL Report. The One-Time Inspection Program is a new program that, when implemented, will be consistent with GALL AMP XI.M32. The staff documents its review and evaluation of the applicant's Oil Analysis Program and One-Time Inspection Program in SER Sections 3.0.3.2.12 and 3.0.3.1.9, respectively. Based on the programs identified above, the staff concludes that the applicant has met the criteria in SRP-LR Section 3.4.2.2.2(1) for further evaluation.

Based on the programs identified above, the staff concludes that the applicant's programs meet the criteria in SRP-LR Section 3.4.2.2.4. For those line items that apply to LRA Section 3.4.2.2.4, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed, so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.5 Loss of Material Due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion

The staff reviewed LRA Section 3.4.2.2.5 against the criteria in SRP-LR Section 3.4.3.2.5.

(1) LRA Section 3.4.2.2.5 addresses the loss of material due to general, pitting, crevice, and microbiologically influenced corrosion for carbon steel piping and components (with or without coating or wrapping) in the steam and power conversion systems buried in soil, stating that the Buried Piping and Tanks Inspection Program manages this aging effect

by (1) preventive measures to mitigate corrosion and (2) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel components. Buried components will be inspected when excavated during maintenance, and there will be inspections within 10 years before the period of extended operation and within the first 10 years of the period of extended operation unless opportunistic inspections occur within these 10-year periods. This program will manage the aging effect of the loss of material so the intended functions of components will not be affected.

SRP-LR Section 3.4.2.2.5 states that the loss of material due to general, pitting, crevice, and microbiologically influenced corrosion may occur in steel piping, piping components, piping elements, and tanks (with or without coating or wrapping) exposed to soil. The Buried Piping and Tanks Inspection Program relies on industry practice, the frequency of pipe excavation, and operating experience to manage the effects of the loss of material from general, pitting, crevice, and microbiologically influenced corrosion. The applicant should verify the effectiveness of its Buried Piping and Tanks Inspection Program by evaluating its inspection frequency and operating experience with buried components to ensure that the loss of material does not occur.

LRA Table 3.4.1, Item 3.4.1-11, addresses the loss of material due to general, pitting, crevice, and microbiologically influenced corrosion for buried steel piping, piping components, piping elements, and tanks (with or without coating and wrapping) exposed to soil. The only AMR item that uses Item 3.4.1-11 of LRA Table 3.4.1 covers the carbon steel buried piping exposed to soil and is included in LRA Tables 3.4.2-3-IP2 and 3.4.2-3-IP3. This piping is part of the AFW system.

During the site audit, the staff reviewed the applicant's new Buried Piping and Tanks Inspection Program and the pertinent documentation on the operating experience with buried piping. The new Buried Piping and Tanks Inspection Program will be implemented within the 10-year period before the period of extended operation, during which time an opportunistic or planned inspection will be performed. Upon entering the period of extended operation, the program will require a planned inspection within 10 years unless an opportunistic inspection has occurred. The staff documents its evaluation of the Buried Piping and Tanks Inspection Program in SER Section 3.0.3.1.2. Based on the programs identified above, the staff concludes that the applicant has met the criteria in SRP-LR Section 3.4.2.2.5(1) for further evaluation.

(2) LRA Section 3.4.2.2.5 addresses the loss of material due to general, pitting, crevice, and microbiologically influenced corrosion for carbon steel heat exchanger components exposed to lubricating oil, stating that the Oil Analysis Program manages this aging effect in the steam and power conversion systems by periodically sampling and analyzing lubricating oil to maintain contaminants within acceptable limits and preserve an environment not conducive to corrosion. The One-Time Inspection Program will use visual inspections or NDEs of representative samples to confirm the effectiveness of the Oil Analysis Program in managing aging effects for components that credit it.

SRP-LR Section 3.4.2.2.5 states that the loss of material due to general, pitting, crevice, and microbiologically influenced corrosion may occur in steel heat exchanger components exposed to lubricating oil. The existing AMP periodically samples and analyzes lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment not conducive to corrosion. However, control of lubricating oil contaminants may not always be fully effective in precluding corrosion; therefore, the applicant should verify the effectiveness of its control of lubricating oil contaminants to ensure that corrosion does not occur. The GALL Report recommends such further evaluation of the program to control lubricating oil chemistry. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that the intended functions of components will be maintained during the period of extended operation.

LRA Table 3.4.1, Item 3.4.1-12, addresses the loss of material due to general, pitting, crevice, and microbiologically influenced corrosion for steel heat exchanger components exposed to lubricating oil. The AMR items that use Item 3.4.1-12 of LRA Table 3.4.1 cover the carbon steel heat exchanger shell exposed to lubricating oil and are included in LRA Tables 3.4.2-3-IP2, 3.4.2-3-IP3, and 3.3.2-19-23-IP3. These heat exchangers are part of the AFW system and the main feedwater pump and services system, respectively.

During the site audits and review of the LRA, the staff confirmed that the applicant uses the Oil Analysis Program to manage the loss-of-material aging effect and verifies the effectiveness of its control of lubricating oil chemistry through the One-Time Inspection Program, which inspects selected components at susceptible locations, as recommended by the GALL Report. The staff reviewed the Oil Analysis Program, which maintains lubricating oil contaminants within acceptable limits. Monitoring and trending the results of oil analyses can identify the aging of components before their intended functions are lost. The staff reviewed the One-Time Inspection Program, which is a new program that, when implemented, will be consistent with GALL AMP XI.M32. The staff documents its review and evaluation of the Oil Analysis Program and the One-Time Inspection Programs in SER Sections 3.0.3.2.12 and 3.0.3.1.9, respectively. Based on the programs identified above, the staff concludes that the applicant has met the criteria in SRP-LR Section 3.4.2.2.5(2) for further evaluation.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.4.2.2.5 criteria. For those line items that apply to LRA Section 3.4.2.2.5, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed, so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.6 Stress-Corrosion Cracking

The staff reviewed LRA Section 3.4.2.2.6 against the criteria in SRP-LR Section 3.4.3.2.6.

LRA Section 3.4.2.2.6 addresses SCC in stainless steel components exposed to steam or treated water, stating that the Water Chemistry Control—Primary and Secondary Program manages this aging effect. The One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control—Primary and Secondary Program by an inspection of a representative sample of components that credit it, including those in stagnant areas and other susceptible locations.

SRP-LR Section 3.4.2.2.6 states that SCC may occur in stainless steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated water greater than 60 °C (140 °F) and in stainless steel piping, piping components, and piping elements exposed to steam. The existing AMP monitors and controls water chemistry to manage the effects of SCC. However, high concentrations of impurities in crevices and stagnant flow conditions may cause SCC; therefore, the GALL Report recommends verifying the effectiveness of water chemistry control programs to ensure that SCC does not occur. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that SCC does not occur and that the intended functions of components will be maintained during the period of extended operation.

For PWRs, SRP-LR Section 3.4.2.2.6 cites GALL Report, Volume 1, AMR Items 4-13 and 4-14 and a number of component-specific AMRs in Chapter VIII of the GALL Report, Volume 2, on SCC in stainless steel piping, piping components, piping elements, tanks, and heat exchanger components in steam and power conversion systems that are exposed to treated water greater than 60 °C (140 °F). Like SRP-LR Section 3.4.2.2.6, the aging management guidance in these GALL-based AMRs recommends that a program corresponding to GALL AMP XI.M2, "Water Chemistry," be credited with the management of SCC in the stainless component surfaces that are exposed to treated water greater than 60 °C (140 °F). The guidance also recommends that a program be credited with verifying the effectiveness of the applicant's water chemistry control program in managing cracking in the component surfaces that are exposed to treated water greater than 60 °C (140 °F). These GALL AMRs state that a One-Time Inspection Program is an acceptable basis for verifying the effectiveness of the water chemistry program in managing cracking in these components.

The staff noted that in LRA Table 3.4.1, Item 3.4.1-13, the applicant stated that this line item applies to BWR plants only. This is in accordance with both SRP-LR Table 3.4-1 and Table 4 of the GALL Report. Since IP2 and IP3 are PWRs, the staff agrees with the applicant's determination that the AMR evaluation result pertaining to this line item in the SRP-LR and in the GALL Report is not applicable to IP.

The staff also noted that in LRA Table 3.4.1, Item 3.4.1-14, the applicant addressed SCC in stainless steel piping, piping components, piping elements, tanks, and heat exchanger components exposed to treated water greater than 60 ºC (140 ºF). During the site audits and review of the LRA, the staff confirmed that the applicant uses the Water Chemistry Control—Primary and Secondary Program to manage the aging effect and verifies the effectiveness of its water chemistry control using the One-Time Inspection Program, which inspects selected components at susceptible locations, as recommended by the GALL Report. The staff reviewed the One-Time Inspection Program, which is a new program that, when implemented, will be consistent with GALL AMP XI.M32. The staff evaluates the Water Chemistry Control—Primary and Secondary Program and the One-Time Inspection Program in SER Sections 3.0.3.2.17 and 3.0.3.1.9, respectively. Based on the programs identified above, the staff concludes that the applicant has met the criteria in SRP-LR Section 3.4.2.2.6 for further evaluation.

In LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3, the staff determined that the applicant aligned some AMRs for secondary-side SG components to LRA AMR Item 3.4.1-14. Specifically, the staff determined that, in LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3, the applicant included AMRs on SCC in stainless steel SG instrumentation system piping, valve, and tubing components that are exposed internally to treated water greater than 60 ºC (140 ºF) and that, in these AMRs, the applicant aligned the AMRs to GALL Report, Volume 1, AMR 4-14 but credited only the Water

Chemistry Control—Primary and Secondary Program to manage SCC in the internal component surfaces that are exposed to treated water greater than 60 ºC (140 ºF). The staff determined that this was inconsistent with the staff's recommended aging management position in GALL Report, Volume 1, AMR 4-14 because, in contrast to the GALL Report guidance, the applicant did not take credit for its One-Time Inspection Program in its AMRs on cracking in the stainless steel secondary-side SG instrumentation system components. In Audit Item 212, the staff asked the applicant to provide its basis for omitting the One-Time Inspection Program in the AMRs on cracking in stainless steel SG instrumentation system piping, valve, and tubing components under internal exposure to treated water greater than 60 ºC (140 ºF).

In its response, dated December 18, 2007, the applicant stated that it would amend the applicable AMRs on cracking in the stainless steel SG instrumentation system piping, valve, and tubing components to make reference to LRA Table 3.1.1, Note 104, which specifically states that the "One-Time Inspection Program will verify effectiveness of the Water Chemistry Control—Primary and Secondary Program." The staff verified that the applicant, in its letter dated December 18, 2007, made the applicable amendment to the AMRs in LRA Table 3.1.2-4-IP2 for these SG instrumentation components. Based on this review of the relevant information in the LRA, the applicant's response to Audit Item 212, and the staff's verification of the amendment to the applicable AMR items for these SG instrumentation components, the staff finds that the applicant has provided an acceptable basis for managing cracking in the stainless steel SG instrumentation system piping, tubing, and valves. This finding is based on the determination that the AMRs for these components have been amended to be consistent with the staff's recommended aging management position in SRP-LR 3.4.2.2.6 and in the GALL Report AMRs that are invoked by this SRP-LR Section.

Based on the programs identified above, the staff concludes that the applicant's programs meet the criteria in SRP-LR Section 3.4.2.2.6 or have provided an acceptable basis for demonstrating that these criteria do not apply to the relevant IP system or systems addressed by the specific SRP-LR item. For those line items that apply to LRA Section 3.4.2.2.6, including the AMRs on cracking in the stainless steel SG instrumentation system piping, tubing, and valves, the staff determines that the LRA is consistent with the SRP-LR and the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed, so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.7 Loss of Material Due to Pitting and Crevice Corrosion

The staff reviewed LRA Section 3.4.2.2.7 against the criteria in SRP-LR Section 3.4.3.2.7.

(1) LRA Section 3.4.2.2.7 addresses the loss of material due to pitting and crevice corrosion for stainless steel and copper alloy components exposed to treated water, stating that the Water Chemistry Control—Primary and Secondary Program manages this aging effect. The steam and power conversion systems have no aluminum components with intended functions that expose them to treated water. The One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control—Primary and Secondary Program by an inspection of a representative sample of components that credit it, including those in areas of stagnant flow and other susceptible locations.

SRP-LR Section 3.4.2.2.7 states that the loss of material due to pitting and crevice corrosion may occur in stainless steel, aluminum, and copper alloy piping, piping components, and piping elements and in stainless steel tanks and heat exchanger components exposed to treated water. The existing AMP monitors and controls water chemistry to manage the effects of the loss of material due to pitting and crevice corrosion. However, the control of water chemistry may not preclude corrosion at locations with stagnant flow conditions; therefore, the GALL Report recommends verifying the effectiveness of water chemistry programs to ensure that corrosion does not occur. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that the intended functions of components will be maintained during the period of extended operation.

For PWRs, SRP-LR Section 3.4.2.2.7(1) cites GALL Report, Volume 1, AMRs Items 4-15 and 4-16, and a number of component-specific AMRs in Chapter VIII of the GALL Report, Volume 2, as applicable to the management of the loss of material due to pitting and crevice corrosion in aluminum and copper alloy steam and power conversion system piping, piping components, and piping elements that are exposed to treated water, and in the stainless steel steam and power conversion system piping, piping components, piping elements, tanks, and heat exchanger components that are exposed to a treated water environment. Like SRP-LR Section 3.4.2.2.7(1), the aging management guidance in these GALL-based AMRs recommends that a program corresponding to GALL AMP XI.M2 be credited for managing the loss of material due to pitting and crevice corrosion in the component surfaces that are exposed to a treated water environment, and that a program be credited with verifying the effectiveness of the applicant's water chemistry control program in managing cracking in the component surfaces that are exposed to a treated water environment. These GALL AMRs state that a One-Time Inspection Program is an acceptable basis for verifying the effectiveness of the water chemistry program in managing the loss of material due to pitting and crevice corrosion in these components.

LRA Table 3.4.1, Item 3.4.1-15 (LRA AMR Item 3.4.1-15), is the applicant's AMR that addresses the loss of material due to pitting and crevice corrosion for aluminum and copper alloy piping, piping components, and piping elements exposed to treated water, as discussed in LRA Section 3.4.2.2.7(1). In its discussion in LRA AMR Item 3.4.1-15, the applicant states that there are no in-scope aluminum components exposed to treated water in the IP steam and power conversion systems. LRA Tables 3.4.2-3-IP2, 3.4.2-3-IP3, and 3.3.2-19-4-IP2 list AMR line items on managing the loss of material due to pitting and crevice corrosion of steam and power conversion copper alloy piping components that are based on LRA AMR Item 3.4.1-15 and the staff's AMR guidance in GALL Report, Volume 1 AMR item 4-15. During the site audits and review of the LRA, the staff confirmed that the applicant uses the Water Chemistry Control—Primary and Secondary Program to manage this aging effect for the copper alloy piping and piping components. The staff also determined that, under Note 404 of LRA Table 3.4.1, the applicant credits its One-Time Inspection Program with verifying the effectiveness of the Water Chemistry Control—Primary and Secondary Program in managing the loss of material in these components, as recommended by the GALL Report. The staff reviewed the One-Time Inspection Program, which is a new program that, when implemented, will be consistent with GALL AMP XI.M32. The staff evaluates the Water Chemistry Control—Primary and Secondary Program and the One-Time Inspection Program in Sections 3.0.3.2.17 and 3.0.3.1.9, respectively. Based on the programs identified above, the staff concludes that the applicant has met the criteria in SRP-LR Section 3.4.2.2.7(1) for further evaluation.

LRA Table 3.4.1, Item 3.4.1-16 (LRA AMR Item 3.4.1-16), contains the applicant's AMR that addresses the loss of material due to pitting and crevice corrosion for stainless steel piping, piping components, and piping elements and for stainless steel tanks and heat exchanger components exposed to treated water, as discussed in LRA Section 3.4.2.2.7(1). During the site audits and review of the LRA, the staff confirmed that, for those stainless steel steam and power conversion components that are exposed to treated water, the applicant credits its Water Chemistry Control—Primary and Secondary Program with managing the aging effect. The staff also determined that, under note 404 of LRA Table 3.4.1, the applicant credits its One-Time Inspection Program with verifying the effectiveness of the Water Chemistry Control—Primary and Secondary Program in managing the loss of material in these components, as recommended in the GALL Report. The staff reviewed the One-Time Inspection Program, which is a new program that, when implemented, will be consistent with GALL AMP XI.M32. The staff evaluates the Water Chemistry Control—Primary and Secondary Program and the One-Time Inspection Programs in Sections 3.0.3.2.17 and 3.0.3.1.9, respectively. Based on the programs identified above, the staff concludes that the applicant has met the criteria in SRP-LR Section 3.4.2.2.7(1) for further evaluation.

The staff noted that, in LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3, the applicant aligned some AMRs for secondary-side SG components to LRA AMR Item 3.4.1-16. Specifically, the staff noted that in LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3, the applicant included AMRs on the loss of material due to pitting and crevice corrosion of stainless steel SG instrumentation system piping, valve, and tubing components that are exposed internally to a treated water environment, and that the applicant aligned these AMRs with GALL Report, Volume 1, AMR Item 4-16, but credited only the Water Chemistry Control—Primary and Secondary Program with managing the loss of material due to pitting and crevice corrosion in the internal component surfaces that are exposed to a treated water environment. The staff noted that this was inconsistent with the staff's recommended aging management position in GALL Report, Volume 1, AMR Item 4-16 because, in contrast to the GALL guidance, the applicant did not take credit for its One-Time Inspection Program in its AMRs regarding the loss of material in these stainless steel secondary-side SG instrumentation system components. In Audit Item 212, the staff asked the applicant to provide its basis for omitting the One-Time Inspection Program in the AMRs on the loss of material due to pitting and crevice corrosion in the stainless steel SG instrumentation system piping, valve, and tubing components that are exposed internally to a treated water environment.

In its response, dated December 18, 2007, the applicant stated that it would amend the applicable AMRs on the loss of material in the stainless steel SG instrumentation system piping, valve, and tubing components to make reference to LRA Table 3.1.1, Note 104, which specifically states that the "One-Time Inspection Program will verify effectiveness of the Water Chemistry Control—Primary and Secondary Program." The staff verified that the applicant, in its letter dated December 18, 2007, made the applicable amendment to the AMRs in LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3 for these SG instrumentation components as noted. Based on this review of the relevant information in the LRA, the applicant's response to Audit Item 212, and the staff's verification of the amendment to the applicable AMR items for these SG instrumentation components, the staff finds that the applicant has provided an acceptable basis for managing the loss of material in the stainless steel SG instrumentation system piping, tubing, and valves. This finding is based on the determination that the AMRs for these components have been amended to be consistent with the staff's recommended aging management position in SRP-LR Section 3.4.2.2.7 and in the GALL Report AMRs that are invoked by this SRP-LR Section.

(2) LRA Section 3.4.2.2.7 addresses the loss of material due to pitting and crevice corrosion for stainless steel piping, piping components, and piping elements exposed to soil, stating that this aging effect is not applicable because there are no stainless steel components exposed to soil in the steam and power conversion systems.

SRP-LR Section 3.4.2.2.7 states that the loss of material due to pitting and crevice corrosion may occur in stainless steel piping, piping components, and piping elements exposed to soil. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that the aging effect is adequately managed.

LRA Table 3.4.1, Items 3.4.1-17, addresses the loss of material due to pitting and crevice corrosion for stainless steel piping, piping components, and piping elements exposed to soil. The discussion column of LRA Table 3.4.1 states that there are no in-scope stainless steel components exposed to soil in the IP2 and IP3 steam and power conversion systems. Therefore, Item 3.4.1-17 of LRA Table 3.4.1 has not been used in the AMR tables.

(3) LRA Section 3.4.2.2.7 addresses the loss of material due to pitting and crevice corrosion for copper alloy piping and components exposed to lubricating oil, stating that the Oil Analysis Program manages this aging effect by periodically sampling and analyzing lubricating oil to maintain contaminants within acceptable limits and preserve an environment not conducive to corrosion. The One-Time Inspection Program will use visual inspections or NDEs of representative samples to confirm the effectiveness of the Oil Analysis Program in managing the aging effects for components that credit it.

SRP-LR Section 3.4.2.2.7 states that the loss of material due to pitting and crevice corrosion may occur in copper alloy piping, piping components, and piping elements exposed to lubricating oil. The existing AMP periodically samples and analyzes lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment not conducive to corrosion. However, the control of lubricating oil contaminants may not always be fully effective in precluding corrosion; therefore, the applicant should verify the effectiveness of lubricating oil contaminant controls to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the program to control lubricating oil chemistry. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion does not occur and that the intended functions of components will be maintained during the period of extended operation.

LRA Table 3.4.1, Item 3.4.1-18, addresses the loss of material due to pitting and crevice corrosion for the copper alloy piping, piping components, and piping elements exposed to a lubricating oil environment. The only AMR items that use Item 3.4.1-18 in LRA Table 3.4.1 are the copper alloy heat exchanger tubes in LRA Tables 3.4.2-3-IP2 and 3.4.2-3-IP3, and the copper alloy valve body in LRA Table 3.3.2-19-15-IP2.

During the site audits and review of the LRA, the staff confirmed that the applicant uses the Oil Analysis Program to manage the loss-of-material aging effect and verifies the effectiveness of the lubricating oil chemistry control by the One-Time Inspection Program, which inspects selected components at susceptible locations, as recommended by the GALL Report. The staff reviewed the Oil Analysis Program, which maintains lubricating oil contaminants within acceptable limits. Monitoring and trending the results of oil analyses can identify the aging of components before their intended functions are lost. The staff reviewed the One-Time Inspection Program, which is a new program that, when implemented, will be consistent with GALL AMP XI.M32. The staff documents its review and evaluation of the Oil Analysis Program and the One-Time Inspection Program in SER Sections 3.0.3.2.12 and 3.0.3.1.9, respectively. Based on the programs identified above, the staff concludes that the applicant has met the criteria in SRP-LR Section 3.4.2.2.7(3) for further evaluation.

Based on the programs identified above, the staff concludes that the applicant's programs meet the criteria in SRP-LR Section 3.4.2.2.7. For those line items that apply to LRA Section 3.4.2.2.7, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed, so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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

The staff reviewed LRA Section 3.4.2.2.8 against the criteria in SRP-LR Section 3.4.3.2.8.

LRA Section 3.4.2.2.8 addresses the loss of material due to pitting, crevice, and microbiologically influenced corrosion in stainless steel piping and components exposed to lubricating oil, stating that the Oil Analysis Program manages this aging effect by periodically sampling and analyzing lubricating oil to maintain contaminants within acceptable limits and preserve an environment not conducive to corrosion. The One-Time Inspection Program will use visual inspections or NDEs of representative samples to confirm the effectiveness of the Oil Analysis Program in managing the aging effects for components that credit it.

SRP-LR Section 3.4.2.2.8 states that the loss of material due to pitting, crevice, and microbiologically influenced corrosion may occur in stainless steel piping, piping components, piping elements, and heat exchanger components exposed to lubricating oil. The existing AMP periodically samples and analyzes lubricating oil to maintain contaminants within acceptable limits, thereby preserving an environment not conducive to corrosion. However, the control of lubricating oil contaminants may not always be fully effective in precluding corrosion; therefore, the effectiveness of lubricating oil contaminant controls should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to manage corrosion to verify the effectiveness of the program to control lubricating oil chemistry. A one-time inspection of selected components at susceptible locations program is an acceptable method to ensure that corrosion does not occur and that the intended functions of components will be maintained during the period of extended operation.

LRA Table 3.4.1, Item 3.4.1-19, addresses the aging effect of the loss of material due to pitting, crevice, and microbiologically influenced corrosion for stainless steel piping, piping components, piping elements, and heat exchanger components exposed to a lubricating oil environment. The AMR items included in the LRA that use Item 3.4.1-19 of LRA Table 3.4.1 cover the stainless steel piping in LRA Table 3.3.2-19-15-IP2, the stainless steel valve bodies in LRA Tables 3.3.2-19-15-IP2, 3.3.2-19-41-IP2, 3.3.2-19-23-IP3 and 3.3.2-19-57-IP3, and the stainless steel tubing in LRA Table 3.3.2-19-57-IP3.

During the site audits and review of the LRA, the staff confirmed that the applicant uses the Oil Analysis Program to manage the loss-of-material aging effect and verifies the effectiveness of the lubricating oil chemistry control by the One-Time Inspection Program, which inspects selected components at susceptible locations, as recommended by the GALL Report. The staff reviewed the Oil Analysis Program, which maintains lubricating oil contaminants within acceptable limits. Monitoring and trending the results of oil analyses can identify the aging of components before their intended functions are lost. The staff also reviewed the One-Time Inspection Program, which is a new program that, when implemented, will be consistent with GALL AMP XI.M32. The staff documents its review and evaluation of the Oil Analysis Program and the One-Time Inspection Programs in SER Sections 3.0.3.2.12 and 3.0.3.1.9, respectively. Based on the programs identified above, the staff concludes that the applicant has met the criteria in SRP-LR Section 3.4.2.2.8 for further evaluation.

Based on the programs identified above, the staff concludes that the applicant's programs meet the criteria in SRP-LR Section 3.4.2.2.8. For those line items that apply to LRA Section 3.4.2.2.8, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed, so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.9 Loss of Material Due to General, Pitting, Crevice, and Galvanic Corrosion

The staff reviewed LRA Section 3.4.2.2.9 against the criteria in SRP-LR Section 3.4.2.2.9.

LRA Section 3.4.2.2.9 addresses the loss of material due to general, pitting, crevice, and galvanic corrosion for steel heat exchanger components exposed to treated water, stating that this aging effect corresponds to a GALL Report line for BWRs only.

SRP-LR Section 3.4.2.2.9 states that the loss of material due to general, pitting, crevice, and galvanic corrosion may occur in steel heat exchanger components exposed to treated water.

In Item 3.4.1.-5 of LRA Table 3.4.1, the applicant stated that this line item applies to BWRs only. Since IP2 and IP3 are PWRs, the staff agrees with the applicant's determination that the AMR evaluation result in the SRP-LR and in the GALL Report is not applicable.

Based on the above, the staff concludes that the criteria in SRP-LR Section 3.4.2.2.9 do not apply.

3.4.2.2.10 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA program.

3.4A.2.3 IP2 AMR Results Not Consistent with, or Not Addressed in, the GALL Report

In LRA Tables 3.4.2-1-IP2 through 3.4.2-4-IP2, the staff reviewed additional details of the AMR results for combinations of material, environment, AERM, and AMP not consistent with, or not addressed in, the GALL Report.

In LRA Tables 3.4.2-1-IP2 through 3.4.2-4-IP2, the applicant indicated, through Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information about how it will manage the aging effects. Specifically, Note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item combination of component, material, and environment is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the line item combination of component, material, and environment is not applicable. Note J indicates that neither the component nor the combination of material and environment for the line item is evaluated in the GALL Report.

For combinations of component type, material, and environment not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether it has demonstrated that the effects of aging will be adequately managed, so that the intended functions will be maintained consistent with the CLB for the period of extended operation. The staff documents its evaluation in the following sections.

3.4A.2.3.1 Main Steam System—Summary of Aging Management Review—
LRA Table 3.4.2-1-IP2

The staff reviewed LRA Table 3.4.2-1-IP2, which summarizes the results of AMR evaluations for the main steam system component groups.

In LRA Table 3.4.2-1-IP2, the applicant used Note I and identified no aging effect for the carbon steel bolting, piping, and piping components, such as steam traps, flow elements, strainer housing, and valve bodies, externally exposed to the plant indoor air environment. Note I for these AMR lines is further supplemented by the plant-specific Note 401, which states that these components are not subject to moisture condensation because they remain at high temperatures during normal plant operation. These components have a similar material and environment as Item SP-1 in the GALL Report, which is applicable to the steel piping, piping components, and piping elements in an external environment of indoor air and does not require an AERM or AMP. On the basis that the LRA components are similar to other GALL Report items for the material and environment (e.g., GALL Report, Volume 2, Table V.F, Line Item V.F-16, whereby the AERM is listed as "none," the AMP is listed as "none," and no further evaluation is required), the staff finds that the effect of plant indoor air on steel components at elevated temperatures will not result in aging that will be of concern during the period of extended operation.

In LRA Table 3.4.2-1-IP2, the applicant applied Note H and identified "cracking–fatigue" as the aging effect for stainless steel piping, piping components, piping elements, and tubing exposed to steam (internal). The applicant has credited the Fatigue Monitoring Program with managing this aging effect. The staff documents its review and evaluation of the proposed Fatigue Monitoring Program in SER Section 3.0.3.2.6.. Based on its review, the staff finds the proposed program acceptable for managing cracking due to fatigue in stainless steel piping and piping components exposed to steam. The ASME Boiler & Pressure Vessel Code, Section III gives curves for fatigue of stainless steel and the Fatigue Monitoring Program is a conservative way to manage this aging effect.

In LRA Table 3.4.2-1-IP2, the applicant applied Note F and identified "cracking–fatigue" as the aging effect for stainless steel strainers exposed to steam (external). The applicant has credited the Fatigue Monitoring Program with managing this aging effect. The staff documents its review and evaluation of the proposed Fatigue Monitoring Program in SER Section 3.0.3.2.6. Based on its review, the staff finds the proposed program acceptable for managing cracking due to fatigue in stainless steel piping and piping components such as strainers exposed to steam. The ASME Boiler & Pressure Vessel Code, Section III gives curves for fatigue of stainless steel and the Fatigue Monitoring Program is a conservative way to manage this aging effect.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of combinations of material, environment, AERM, and AMP 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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4A.2.3.2 Main Feedwater System—Summary of Aging Management Review—LRA Table 3.4.2-2-IP2

The staff reviewed LRA Table 3.4.2-2-IP2, which summarizes the results of AMR evaluations for the main feedwater system component groups.

In LRA Table 3.4.2-2-IP2, the applicant used Note I and identified no aging effect for the carbon steel bolting, piping, and valve bodies externally exposed to the plant indoor air environment. Note I for these AMR lines is further supplemented by the plant-specific Note 401, which states that the applicable components are not subject to moisture condensation because they remain at high temperatures during normal plant operation. The components have a similar material and environment as Item SP-1 in the GALL Report, which is applicable to the steel piping, piping components, and piping elements in an external environment of indoor air and does not require an AERM or AMP. On the basis that the LRA components are similar to other GALL Report items for the material and environment (e.g., GALL Report, Volume 2, Table V.F, Line Item V.F-16, whereby the AERM is listed as "none," the AMP is listed as "none," and no further evaluation is required), the staff finds that the effect of plant indoor air on steel components at elevated temperatures will not result in aging that will be of concern during the period of extended operation.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of combinations of material, environment, AERM, and AMP 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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4A.2.3.3 Auxiliary Feedwater System—Summary of Aging Management Review—
LRA Table 3.4.2-3-IP2

The staff reviewed LRA Table 3.4.2-3-IP2, which summarizes the results of AMR evaluations for the AFW system component groups.

In LRA Table 3.4.2-3-IP2, the applicant applied Note F and identified "cracking–fatigue" as the aging effect for stainless steel strainers exposed to steam (external). The applicant has credited the Fatigue Monitoring Program with managing this aging effect. The staff reviewed and evaluated the proposed Fatigue Monitoring Program and documents its evaluation in SER Section 3.0.3.2.6. Based on its review, the staff finds the proposed program acceptable for managing cracking due to fatigue in stainless steel piping and piping components such as strainers exposed to steam. The ASME Boiler & Pressure Vessel Code, Section III gives curves for fatigue of stainless steel and the Fatigue Monitoring Program is a conservative way to manage this aging effect.

In LRA Table 3.4.2-3-IP2, the applicant proposed using the External Surfaces Monitoring Program to manage the loss of material in stainless steel piping, tubing, and valve bodies exposed to an external environment of outdoor air. The applicant applied Note G to indicate that the environment for these components and material is not included in the GALL Report. The staff finds that the applicant's External Surfaces Monitoring Program includes periodic visual inspections of external surfaces during the system engineers' walkdowns of the systems. The staff evaluates the External Surfaces Monitoring Program in SER Section 3.0.3.2.5. The staff finds that the aging effect of the loss of material in stainless steel piping tubing and valve bodies exposed to an external environment of outdoor air will be adequately managed by using the External Surfaces Monitoring Program.

In LRA Table 3.4.2-3-IP2, the applicant proposed using the One-Time Inspection Program to manage the loss of material in stainless steel tubing and valve bodies exposed to a treated water (internal) environment. The applicant applied Note G and plant-specific Note 407 to indicate that the environment for these components and material is not included in the GALL Report. The staff finds that the applicant's One-Time Inspection Program will use inspections to detect whether these components are incurring a loss of material. The program uses both visual and NDE techniques for inspection. The program includes a provision that any unacceptable results or findings will be evaluated in accordance with the site corrective action process to determine the need for subsequent (including periodic) inspections. The staff evaluates the External Surfaces Monitoring Program in SER Section 3.0.3.1.9. Based on the above, the staff finds that the aging effect of the loss of material in these components will be adequately managed by using the One-Time Inspection Program.

In LRA Table 3.4.2-3-IP2, the applicant applied Note G and identified the loss of material as the aging effect for carbon steel piping exposed to treated water (internal) and proposed the Periodic Surveillance and Preventive Maintenance Program to manage the effects of aging. The staff's review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.3.7. In addition to Note G, the applicant applies Note 407 to this line item. Note 407 states, "This treated water environment includes water that has been treated but is not maintained by a chemistry control program, such as water from the city water system. There is no environment in NUREG-1801 that will support a useful comparison for this line." The GALL Report states that, "Raw water may contain contaminates, including oil and boric acid, depending on the location, as well as originally treated water that is not monitored by a chemistry program." Therefore, it is the staff's opinion that this environment should be classified as raw water according to the GALL Report definition. The applicant has credited the Periodic Surveillance and Preventive Maintenance Program with managing the aging effect. This program includes activities to monitor components to detect degradation and monitor parameters such as wall thickness and surface condition. The program uses both visual and NDE techniques to perform inspections. Based on its review, the staff finds the proposed program acceptable for managing the loss of material in steel piping and piping components such as valve bodies.

In LRA Table 3.4.2-3-IP2, the applicant proposed using the Bolting Integrity Program to manage the loss of material in stainless steel bolting exposed to the outdoor air (external) environment. The applicant applied Note G to indicate that the environment for this component and material is not included in the GALL Report. The staff evaluates the Bolting Integrity Program in Section 3.0.3.2.2. This program is also recommended in Table 4, Item 22, of the GALL Report to manage the loss of material due to general, pitting, and crevice corrosion in steel bolting exposed to outdoor air (external). Based on the above, the staff finds that the aging effect of the loss of material in these components will be adequately managed by using the Bolting Integrity Program.

In LRA Table 3.4.2-3-IP2, the applicant applied Note G and plant-specific Note 402 to carbon steel piping externally exposed to condensation with an aging effect of loss of material. Note 402 states, "[t]his environment is inside the condensate storage tank [CST]. The tank vapor space is nitrogen blanketed but the environment is conservatively assumed to be condensation." The applicant proposed the Water Chemistry Control – Primary and Secondary Program to manage the effects of aging. The staff's review of Water Chemistry Control – Primary and Secondary Program is documented in SER Section 3.0.3.2.17. In Table VIII.H, Line Item VIII.H-10 of the GALL Report, it recommends the use of the External Surfaces Monitoring Program to manage loss of material on external surfaces of carbon steel piping exposed to condensation. Therefore, loss of material is an appropriate aging effect for this material/environment combination. However, the piping component of interest is internal to the CST. Therefore, use of the External Surfaces Monitoring Program is not practical. The staff notes that during normal operation, the tank vapor space is blanketed with nitrogen which will reduce the presence of oxygen. The staff agrees that consideration of condensation as an environment is conservative. The applicant proposed to use the water chemistry control program in lieu the External Surfaces Monitoring Program. The staff finds that use of the Water Chemistry Control – Primary and Secondary Program is acceptable because the program periodically monitors and controls known detrimental contaminants such as chlorides, fluorides, dissolved oxygen, and sulfate concentrations below the levels known to result in loss of material or cracking. Additionally, water chemistry control is in accordance with industry guideline EPRI TR-102134 for secondary water chemistry in PWRs. As noted previously, the presence of oxygen which contributes to loss of material is reduced by the presence of the nitrogen blanket. Based on the above, the staff finds the applicant's AMR results acceptable.

In LRA Table 3.4.2-3-IP2, the applicant applied Note G and identified the loss of material as the aging effect for carbon steel tanks exposed to concrete and oiled sand (external) and proposed the Aboveground Steel Tanks Program to manage this aging effect. The staff's review of the Aboveground Steel Tanks Program is documented in SER Section 3.0.3.2.1. The staff finds this acceptable because the staff has accepted considering steel tanks exposed to concrete and oiled sand bounded by steel tanks exposed to soil which is in the GALL Report.

In LRA Table 3.4.2-3-IP2, the applicant applied Note G and identified the loss of material as the aging effect for copper alloy tubing exposed to steam (internal) and proposed the Water Chemistry Control – Primary and Secondary to manage this aging effect. The staff's review of Water Chemistry Control – Primary and Secondary Program is documented in SER Section 3.0.3.2.17. Based on the review of this program, the staff finds the proposed program acceptable for managing loss of material due to exposure to steam (internal) because American Society of Metals (ASM) Handbook, Volume 13B, "Corrosion of Metals," page 138, 2005 states that steam is not corrosive to copper alloys as long as levels of carbon dioxide, oxygen, and ammonia remain low. These species will be controlled by the Water Chemistry Control – Primary and Secondary to manage this aging effect.

In LRA Table 3.4.2-3-IP2, the applicant applied Note H and identified "cracking–fatigue" as the aging effect for stainless steel piping, piping components, and tubing exposed to steam (internal). The applicant referenced this combination as a metal fatigue TLAA. The staff's evaluation of the metal fatigue TLAAs is documented in SER Section 4.3.2. During an audit, the staff questioned the applicant about these AMR results, to gain a better understanding of the conditions and how cracking would be managed (Audit Item 233). In its response, dated December 18, 2007, the applicant provided additional explanation of the conditions potentially leading to cracking and the consequences of a crack on performance of intended function. The staff reviewed this information and concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences. Therefore, the staff finds the applicant's AMR results acceptable.

The applicant has credited the Fatigue Monitoring Program with managing this aging effect. The staff reviewed and evaluated the proposed Fatigue Monitoring Program and documents its evaluation in SER Section 3.0.3.2.6. Based on its review, the staff finds the proposed program acceptable for managing cracking due to fatigue in stainless steel piping and piping components exposed to steam. The ASME Boiler & Pressure Vessel Code, Section III gives curves for fatigue of stainless steel and the Fatigue Monitoring Program is a conservative way to manage this aging effect.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of combinations of material, environment, AERM, and AMP 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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4A.2.3.4 Steam Generator Blowdown System—Summary of Aging Management Review—LRA Table 3.4.2-4-IP2

The staff reviewed LRA Table 3.4.2-4-IP2, which summarizes the results of AMR evaluations for the SG blowdown system component groups.

In LRA Table 3.4.2-4-IP2, the applicant used Note I and identified no aging effect for the carbon steel bolting, piping, and valve bodies externally exposed to the plant indoor air environment. Note I for these AMR lines is further supplemented by the plant-specific Note 401, which states that the applicable components are not subject to moisture condensation because they remain at high temperatures during normal plant operation. The components have a similar material and environment as Item SP-1 in the GALL Report, which is applicable to the steel piping,

piping components, and piping elements in an external environment of indoor air and does not require an AERM or AMP. On the basis that the LRA components are similar to other GALL Report items for the material and environment (e.g., GALL Report, Volume 2, Item V.F-16, whereby the AERM is listed as “none,” the AMP is listed as “none,” and no further evaluation is required), the staff finds that the effect of plant indoor air on steel components at elevated temperatures will not result in aging that will be of concern during the period of extended operation.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of combinations of material, environment, AERM, and AMP 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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4A.2.3.5 IP2 Auxiliary Feedwater Pump Room Fire Event—Summary of Aging Management Review—LRA Tables 3.4.2-5-1-IP2 through 3.4.2-5-13-IP2

The staff reviewed LRA Tables 3.4.2-5-1-IP2 through 3.4.2-5.13-IP2 which summarize the results of AMR evaluations for the IP2 AFW pump room fire event component groups.

<u>LRA Table 3.4.2-5-2-IP2 Condensate System</u>

By letter dated June 12, 2009, the applicant amended its LRA to include AMR line items for the following material/environment/aging effect combinations: titanium heat exchanger tubes exposed to externally to steam with an aging effect of loss of material and fouling; stainless steel heat exchanger tubes exposed externally to steam with an aging effect of fouling; and titanium heat exchanger tubes exposed internally to treated water with an aging effect of loss of material and fouling. The applicant proposed to manage these aging effects by using the Water Chemistry Control – Primary and Secondary program. The staff documents its review of the Water Chemistry Control – Primary and Secondary program in SER Section 3.0.3.2.17. The Water Chemistry Control - Primary and Secondary Program includes preventive measures that manage loss of material, cracking, or fouling for these components and follows EPRI Guidelines in TR-105714, Rev. 5, Pressurized Water Reactor Primary Water Chemistry Guidelines, and TR-102134, Rev. 6, Pressurized Water Reactor Secondary Chemistry Guidelines. Because this system is non-safety related, and the applicant is adhering to appropriate EPRI Guidelines, the staff finds that this aging effect will be effectively managed by this program.

By letter dated June 12, 2009, the applicant amended its LRA to state that titanium heat exchanger tubes exposed internally to raw water with an aging effect of fouling and loss of material will be managed by using the Periodic Surveillance and Preventive Maintenance Program. The staff’s review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.3.7. The Periodic Surveillance and Preventive Maintenance Program enhancements add new activities to the plant’s preventive maintenance and surveillance programs, which implement preventive maintenance and surveillance testing activities through repetitive tasks or routine monitoring of plant operations. On the basis of its review, the staff finds that because these components will be inspected periodically for loss of material and fouling, the aging effect for the component, material and environment combination will be effectively managed by this aging management program.

LRA Table 3.4.2-5-3-IP2 Circulating Water System

By letter dated June 12, 2009, the applicant added line items with Note G for elastomer expansion joints exposed externally to outdoor air with the aging effects of cracking and change of material properties. Note G is environment not in GALL for this component and material. The applicant proposes to manage the effects of aging using the Periodic Surveillance and Preventive Maintenance Program. The staff's review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER section 3.0.3.3.7. The Periodic Surveillance and Preventive Maintenance Program enhancements add new activities to the plant's preventive maintenance and surveillance programs, which implement preventive maintenance and surveillance testing activities through repetitive tasks or routine monitoring of plant operations. On the basis of its review, the staff finds that because these components will be inspected periodically for cracking and change of material properties, the aging effect for the component, material and environment combination will be effectively managed by this aging management program.

LRA Table 3.4.2-5-4-IP2 City Water System

By letter dated June 12, 2009, the applicant added line items with Note G for carbon steel piping, sight glasses, and strainer bodies exposed to treated water on the inside with an aging effect of loss of material. Note G is environment not in GALL for this component and material. The applicant proposes to manage the effects of aging using the Periodic Surveillance and Preventive Maintenance Program. The staff's review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER section 3.0.3.3.7. The Periodic Surveillance and Preventive Maintenance Program enhancements add new activities to the plant's preventive maintenance and surveillance programs, which implement preventive maintenance and surveillance testing activities through repetitive tasks or routine monitoring of plant operations. On the basis of its review, the staff finds that because these components will be inspected periodically for cracking and change of material properties, the aging effect for the component, material and environment combinations will be effectively managed by this AMP.

In a letter dated June 12, 2009, the applicant referenced Note G for stainless steel bolting, piping, tubing, and valve bodies exposed to an external environment of outdoor air, with the aging effect of loss of material. Note G is environment not in GALL Report for this component and material. The applicant proposed to manage the effects of aging of bolting components by the Bolting Integrity Program. The staff's evaluation of these programs is documented in SER Section 3.0.3.2.2. The Bolting Integrity Program conducts inspections of bolting in accordance with the ASME Code, Section XI, Tables IWB 2500-1, IWC 2500-1 and IWD 2500-1, using visual techniques to inspect for leakage, loss of material, cracking, and loss of preload/loss of prestress. The applicant proposed to manage the effects of aging for piping, tubing and valve bodies exposed externally to outdoor air by using the External Surfaces Monitoring Program. The staff's review of the External Surfaces Monitoring Program is documented in SER section 3.0.3.2.5. The staff determined that this program will perform periodic visual inspections which will be capable of detecting loss of material and evidence of corrosion in these stainless steel components. On the basis of its review, the staff finds that, because these components will be inspected periodically for loss of material, the aging effect for the component, material and environment combinations will be effectively managed by this program.

In a letter dated June 12, 2009, the applicant referenced Note G, Note 407 for stainless steel flexible hose, piping, strainer, strainer housing, tubing and valve bodies exposed internally to treated water with the aging effect of loss of material. Note G is environment not in GALL Report for this component and material. Note 407 states: “This treated water environment includes water that has been treated but is not maintained by a chemistry control program, such as water from the city water system. There is no environment in NUREG-1801 that will support a useful comparison for this line.” The applicant proposed to manage the aging using the One-Time Inspection Program. The staff’s evaluation of this program is documented in SER Section 3.0.3.1.9. The staff notes that it is not anticipated that city water will attack stainless steel components because stainless steel is commonly used to contain potable water supplies. The staff notes the use of the One-Time Inspection Program will verify that corrosion is not occurring or, if loss of material is identified during the one-time inspection, a corrective action report will be prepared and an evaluation will be conducted which may result in additional inspections of these components. On the basis of its review, the staff finds that, because these components will be inspected to confirm whether loss of material has occurred and additional inspections may be conducted if degradation is found, the aging effect for the component, material and environment combinations will be effectively managed by this program.

In a letter dated June 12, 2009, the applicant referenced Note G, Note 407, for sight glasses exposed externally to outdoor air and internally to treated water with no aging effect and no aging management program required. Note G is environment not in GALL Report for this component and material. The staff notes that GALL AMR Line Item V.F-10 states that glass exposed to air does not experience an aging effect requiring management. The staff further notes that GALL AMR Line Item VII.J-7 states that glass exposed to treated water does not experience an aging effect requiring management. The staff determines that sight glasses exposed to outdoor air and treated water do not have an aging effect requiring management. On the basis of its review, the staff finds that because the applicant’s determination is consistent with the recommendations of the GALL Report for glass exposed to outdoor air and treated water, the applicant has appropriately concluded that these components do not experience an aging effect requiring management.

In a letter dated June 12, 2009, the applicant referenced Note G, Note 407, for copper alloy with greater than 15 percent zinc strainer housing exposed on the interior to treated water with an aging effect of loss of material. Note G is environment not in GALL Report for this component and material. The applicant proposes that the aging effects be managed using the Periodic Surveillance and Preventive Maintenance Program and the Selective Leaching Program. The staff’s review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.3.7. The staff’s review of the Selective Leaching Program is documented in SER Section 3.0.3.1.13. The Periodic Surveillance and Preventive Maintenance Program enhancements add new activities to the plant’s preventive maintenance and surveillance programs, which generally implement preventive maintenance and surveillance testing activities through repetitive tasks or routine monitoring of plant operations. On the basis of its review, the staff finds that because these components will be inspected periodically for loss of material, the aging effect for the component, material and environment combination will be effectively managed by the Periodic Surveillance and Preventive Maintenance Program. The Selective Leaching Program will include a one-time visual inspection, hardness measurement (where feasible based on form and configuration) or other industry-accepted mechanical inspection techniques of selected components that may be susceptible to selective leaching to determine whether loss of material due to selective leaching has occurred and whether the process will affect component ability to perform intended functions during the period of extended operation. On the basis of its review, the staff finds that the Selective Leaching Program will determine if selective leaching has occurred and if so, it will be evaluated to determine if additional inspections are required. Accordingly, the staff finds that the aging effects for these component, material and environment combinations will be effectively managed by these programs.

LRA Table 3.4.3.-5-5-IP2 Wash Water System

In a letter dated June 9, 2009, the applicant referenced Note G, for stainless steel bolting exposed to outdoor air with an aging effect of loss of material. Note G is environment not in GALL Report for this component and material. The applicant proposed using the Bolting Integrity Program to manage the effects of aging. The staff's evaluation of this program is documented in SER Section 3.0.3.2.2. The Bolting Integrity Program conducts inspections of bolting in accordance with the ASME Section XI, Tables IWB 2500-1, IWC 2500-1 and IWD 2500-1, using visual techniques to inspect for leakage, loss of material, cracking, and loss of preload/loss of prestress. On the basis of its review, the staff finds that, because these components will be inspected periodically for loss of material, the aging effect for the component, material and environment combination will be effectively managed by this program.

In a letter dated June 12, 2009, the applicant referenced Note G, for elastomer expansion joints exposed to outdoor air with the aging effects of cracking and change of material properties. Note G is environment not in GALL Report for this component and material. The applicant proposes to manage the effects of aging using the Periodic Surveillance and Preventive Maintenance Program. The staff's review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER section 3.0.3.3.7. The Periodic Surveillance and Preventive Maintenance Program enhancements add new activities to the plant's preventive maintenance and surveillance programs, which generally implement preventive maintenance and surveillance testing activities through repetitive tasks or routine monitoring of plant operations. On the basis of its review, the staff finds that because these components will be inspected periodically for cracking and change of material properties, the aging effect for the component, material and environment combination will be effectively managed by this AMP.

In a letter dated June 12, 2009, the applicant referenced Note G for stainless steel flexible hose, piping, pump casing, tubing and valve bodies exposed to an externally to outdoor air, with the aging effect of loss of material. Note G is environment not in GALL Report for this component and material. The applicant proposed using the External Surfaces Monitoring Program to manage this aging effect. The staff's review of the External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.5. This program involves periodic visual inspection of SSCs in scope for license renewal to identify evidence of corrosion. On the basis of its review, the staff finds that because these components will be inspected periodically for signs of corrosion, the aging effect for the component, material and environment combinations will be effectively managed by this AMP.

LRA Table 3.4.2-5-7-IP2 Instrument Air System

By letter dated June 12, 2009, the applicant referenced Note G, for stainless steel bolting exposed to outdoor air with an aging effect of loss of material. Note G is environment not in GALL Report for this component and material. The applicant proposed using the Bolting Integrity Program to manage the effects of aging. The staff's evaluation of this program is documented in SER Section 3.0.3.2.2. The Bolting Integrity Program conducts inspections of bolting in accordance with the ASME Code, Section XI, Tables IWB 2500-1, IWC 2500-1 and IWD 2500-1, using visual techniques to inspect for leakage, loss of material, cracking, and loss of preload/loss of prestress. On the basis of its review, the staff finds that, because these components will be inspected periodically for loss of material, the aging effect for the component, material and environment combination will be effectively managed by this program.

By letter dated June 12, 2009, the applicant referenced Note G, Note 407, for copper alloy with greater than 15 percent zinc heat exchanger tubes exposed on the interior to condensation with an aging effect of loss of material. Note G is environment not in GALL Report for this component and material. The applicant proposes that the aging effects be managed using the Periodic Surveillance and Preventive Maintenance Program. The staff's review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.3.7. The Periodic Surveillance and Preventive Maintenance Program enhancements add new activities to the plant's preventive maintenance and surveillance programs, which generally implement preventive maintenance and surveillance testing activities through repetitive tasks or routine monitoring of plant operations. On the basis of its review, the staff finds that because these components will be inspected periodically for loss of material, the aging effect for the component, material and environment combination will be effectively managed by the Periodic Surveillance and Preventive Maintenance Program.

<u>LRA Table 3.4.2-5-9-IP2 Service Water System</u>

In a letter dated June 12, 2009, the applicant referenced Note E, for stainless steel bolting exposed to condensation with an aging effect of loss of material. Note E is defined as the AMR is consistent with the GALL Report AMR result for material, environment and aging effect, but a different AMP is credited, or the GALL Report identifies that a plant-specific AMP should be used. The applicant proposed using the Bolting Integrity Program to manage the effects of aging. The staff's evaluation of this program is documented in SER Section 3.0.3.2.2. The Bolting Integrity Program conducts inspections of bolting in accordance with the ASME Section XI, Tables IWB 2500-1, IWC 2500-1 and IWD 2500-1, using visual techniques to inspect for leakage, loss of material, cracking, and loss of preload/loss of prestress. On the basis of its review, the staff finds that, because these components will be inspected periodically for loss of material, the aging effect for the component, material and environment combination will be effectively managed by this AMP.

By letter dated June 12, 2009, the applicant referenced Note E for stainless steel piping tubing and valve bodies and copper alloy tubing exposed to an external environment of condensation, with the aging effect of loss of material. Note E is defined as the AMR is consistent with the GALL Report AMR result for material, environment and aging effect, but a different AMP is credited, or the GALL Report identifies that a plant-specific AMP should be used. The applicant proposed using the External Surfaces Monitoring Program to manage this aging effect. The staff's review of the External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.5. This program involves visual inspection of SSCs in scope for license renewal to identify evidence of corrosion. On the basis of its review, the staff finds that because these components will be inspected periodically for signs of corrosion, the aging effect for the component, material and environment combinations will be effectively managed by this AMP.

<u>LRA Table 3.4.2-5-10-IP2 Lube Oil System</u>

By letter dated June 12, 2009, the applicant added line items with Note F for titanium heat exchanger tubes exposed internally to lube oil and externally to raw water with the aging effects of fouling and loss of material. Note F is material not in the GALL Report for this component. The applicant proposed to manage these aging effects by using the Oil Analysis Program for the lube oil environment and the Service Water Integrity Program for the raw water environment. The staff's evaluation of the Oil Analysis Program is documented in SER Section 3.0.3.2.12. The Oil Analysis Program maintains oil systems free of contaminants (primarily water and particulates) to preserve an environment that is not conducive to loss of material, cracking, or fouling. Activities include sampling and analysis of lubricating oil in accordance with industry standards such as ISO 4406, ASTM D445, ASTM D4951, and ASTM D96.The staff's review of the Service Water Integrity Program is documented in SER Section 3.0.3.1.14. The Service Water Integrity Program implements the recommendations of GL 89-13 for managing the effects of aging on the service water (SW) system, during the period of extended operation. The program inspects components for erosion, corrosion, and biofouling to confirm the heat transfer capability of safety-related heat exchangers cooled by SW. Chemical treatment with biocides and sodium hypochlorite and periodic cleaning and flushing of infrequently used loops are methods for controlling fouling within the heat exchangers and managing loss of material in SW components. On the basis of its review, the staff finds that because these components will be inspected periodically for signs of corrosion, the aging effect for the component, material and environment combinations will be effectively managed by these aging management programs.

LRA Table 3.4.2-5-11-IP2 River Water Service System

By letter dated June 12, 2009, the applicant referenced Note G for stainless steel bolting, tubing, and valve bodies exposed to an external environment of outdoor air, with the aging effect of loss of material. Note G is environment not in GALL Report for this component and material. The applicant proposed to manage the effects of aging of bolting components by using the Bolting Integrity Program. The staff's evaluation of these programs is documented in SER Section 3.0.3.2.2. The Bolting Integrity Program conducts inspections of bolting in accordance with the ASME Code, Section XI, Tables IWB 2500-1, IWC 2500-1 and IWD 2500-1, using visual techniques to inspect for leakage, loss of material, cracking, and loss of preload/loss of prestress. The applicant proposed to manage the effects of aging for tubing and valve bodies exposed externally to outdoor air by using the External Surfaces Monitoring Program. The staff's review of the External Surfaces Monitoring Program is documented in SER section 3.0.3.2.5. The staff determined that this program will perform periodic visual inspections which will be capable of detecting loss of material and evidence of corrosion in these stainless steel components. On the basis of its review, the staff finds that, because these components will be inspected periodically for loss of material, the aging effect for the component, material and environment combinations will be effectively managed by this program.

LRA Table 3.4.2-5-12-IP2 Fresh Water Cooling System

By letter dated June 12, 2009, the applicant amended its LRA to state that titanium heat exchanger tubes exposed internally to raw water and externally to treated water with the aging effects of fouling and loss of material, and referenced Note F. Note F indicates that the material is not in the GALL Report for this component. The applicant proposes to manage the effects of aging using the Periodic Surveillance and Preventive Maintenance Program. The staff's review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.3.7. The Periodic Surveillance and Preventive Maintenance Program enhancements add new activities to the plant's preventive maintenance and surveillance programs, which generally implement preventive maintenance and surveillance testing activities through repetitive tasks or routine monitoring of plant operations. On the basis of its review, the staff finds that because these components will be inspected periodically for loss of material and fouling, the aging effect for the component, material and environment combinations will be effectively managed by this aging management program.

LRA Table 3.4.2-5-13-IP2 IP1 Station Air System

The staff reviewed LRA Table 3.4.2-5-13-IP2, which summarizes the results of AMR results for the IP1 station air system with regard to the IP2 AFW pump room fire event. The staff's review did not identify any line items with plant-specific Notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.4.2.1.

3.4B.2.3 IP3 AMR Results Not Consistent with, or Not Addressed in, the GALL Report

In LRA Tables 3.4.2-1-IP3 through 3.4.2-4-IP3, the staff reviewed additional details of the AMR results for combinations of material, environment, AERM, and AMP not consistent with, or not addressed in, the GALL Report.

In LRA Tables 3.4.2-1-IP3 through 3.4.2-4-IP3, the applicant indicated, through Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information about how it will manage the aging effects. Specifically, Note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item combination of component, material, and environment is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the line item combination of component, material, and environment is not applicable. Note J indicates that neither the component nor the combination of material and environment for the line item is evaluated in the GALL Report.

For combinations of component type, material, and environment not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation. The staff documents its evaluation in the following sections.

3.4B.2.3.1 Main Steam System—Summary of Aging Management Review—
LRA Table 3.4.2-1-IP3

The staff reviewed LRA Table 3.4.2-1-IP3, which summarizes the results of AMR evaluations for the main steam system component groups.

In LRA Table 3.4.2-1-IP3, the applicant used Note I and identified no aging effect for the carbon steel bolting, piping, and piping components such as steam trap, flow element, strainer housing, and valve bodies, externally exposed to the plant indoor air environment. Note I for these AMR lines is further supplemented by the plant-specific Note 401, which implies that these components are not subject to moisture condensation because they remain at high temperatures during normal plant operation. These components have a similar material and environment as Item SP-1 in the GALL Report, which is applicable to the steel piping, piping components, and piping elements in an external environment of indoor air and does not require an AERM or AMP. On the basis that the LRA components are similar to other GALL Report items for the material and environment (e.g., GALL Report, Volume 2, Table V.F, Line Item V.F-16, whereby the AERM is listed as "none," the AMP is listed as "none," and no further evaluation is required), the staff finds that the effect of plant indoor air on steel components at elevated temperatures will not result in aging that will be of concern during the period of extended operation.

In LRA Table 3.4.2-1-IP3, the applicant applied Note H and identified "cracking–fatigue" as the aging effect for stainless steel piping, piping components, piping elements, tubing, strainers, thermowells, and valve bodies exposed to steam (internal). The applicant has credited the Fatigue Monitoring Program with managing this aging effect. The staff reviewed and evaluated the proposed Fatigue Monitoring Program and documents its evaluation in Section 3.0.3.2.6. Based on its review, the staff finds the proposed program acceptable for managing cracking due to fatigue in stainless steel piping and piping components exposed to steam. The ASME Boiler & Pressure Vessel Code, Section III gives curves for fatigue of stainless steel and the Fatigue Monitoring Program is a conservative way to manage this aging effect.

In LRA Table 3.4.2-1-IP3, the applicant applied Note F and identified "cracking–fatigue" as the aging effect for stainless steel strainers exposed to steam (external). The applicant has credited the Fatigue Monitoring Program with managing this aging effect. The staff reviewed and evaluated the proposed Fatigue Monitoring Program and documents its evaluation in Section 3.0.3.2.6. Based on its review, the staff finds the proposed program acceptable for managing cracking due to fatigue in stainless steel piping and piping components exposed to steam. The ASME Boiler & Pressure Vessel Code, Section III gives curves for fatigue of stainless steel and the Fatigue Monitoring Program is a conservative way to manage this aging effect.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of combinations of material, environment, AERM, and AMP 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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4B.2.3.2 Main Feedwater System—Summary of Aging Management Review—LRA Table 3.4.2-2-IP3

The staff reviewed LRA Table 3.4.2-2-IP3, which summarizes the results of AMR evaluations for the main feedwater system component groups.

In LRA Table 3.4.2-2-IP3, the applicant used Note I and identified no aging effects for the carbon steel bolting, piping, and valve bodies externally exposed to the plant indoor air environment. Note I for these AMR lines is further supplemented by the plant-specific Note 401, which implies that the applicable components are not subject to moisture condensation because they remain at high temperatures during normal plant operation. The components have a similar material and environment as Item SP-1 in the GALL Report, which is applicable to the steel piping, piping components, and piping elements in an external environment of indoor air and does not require an AERM or AMP. On the basis that the LRA components are similar to other GALL Report items for the material and environment (e.g., GALL Report, Volume 2, Table V.F, Line Item V.F-16, whereby the AERM is listed as "none," the AMP is listed as "none," and no further evaluation is required), the staff finds that the effect of plant indoor air on steel components at elevated temperatures will not result in aging that will be of concern during the period of extended operation.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of combinations of material, environment, AERM, and AMP 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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4B.2.3.3 Auxiliary Feedwater System—Summary of Aging Management Review—LRA Table 3.4.2-3-IP3

The staff reviewed LRA Table 3.4.2-3-IP3, which summarizes the results of AMR evaluations for the AFW system component groups.

In LRA Table 3.4.2-3-IP3, the applicant applied Note F and identified "cracking–fatigue" as the aging effect for stainless steel strainer exposed to steam (external). The applicant has credited the Fatigue Monitoring Program with managing this aging effect. The staff reviewed and evaluated the proposed Fatigue Monitoring Program and documents its evaluation in SER Section 3.0.3.2.6. Based on the review of this program, the staff finds the proposed program acceptable for managing cracking due to fatigue in stainless steel piping and piping components such as strainers exposed to steam. The ASME Boiler & Pressure Vessel Code, Section III gives curves for fatigue of stainless steel and the Fatigue Monitoring Program is a conservative way to manage this aging effect.

In LRA Table 3.4.2-3-IP3, the applicant proposed using the External Surfaces Monitoring Program to manage the loss of material in stainless steel piping, tubing, and valve bodies exposed to an external environment of outdoor air. The applicant applied Note G to indicate that the environment for these components and material is not included in the GALL Report. The staff finds that the applicant's External Surfaces Monitoring Program includes periodic visual inspections of external surfaces during the system engineer's walkdowns of the systems. The staff evaluates the External Surfaces Monitoring Program in SER Section 3.0.3.2.5. The staff finds that the aging effect of the loss of material in stainless steel piping and tanks exposed to an external environment of outdoor air will be adequately managed by using the External Surfaces Monitoring Program.

In LRA Table 3.4.2-3-IP3, the applicant proposed using the Bolting Integrity Program to manage the loss of material in stainless steel bolting exposed to the outdoor air (external) environment. The applicant applied Note G to indicate that the environment for this component and material is not included in the GALL Report. The staff documents its evaluation of the Bolting Integrity Program in SER Section 3.0.3.2.2. This program is also recommended in the GALL Report, Table 4, Item 22, to manage the loss of material due to general, pitting, and crevice corrosion in steel bolting exposed to outdoor air (external). Based on the above, the staff finds that the aging effect of the loss of material in these components will be adequately managed by using the Bolting Integrity Program.

In LRA Table 3.4.2-3-IP3, the applicant applied Note G and identified the loss of material as the aging effect for carbon steel tanks exposed to concrete and oiled sand (external) and proposed the Aboveground Steel Tanks Program to manage this aging effect. The staff's review of the Aboveground Steel Tanks Program is documented in SER Section 3.0.3.2.1. The staff finds this acceptable because the staff has accepted considering steel tanks exposed to concrete and oiled sand bounded by steel tanks exposed to soil which is in the GALL Report.

In LRA Table 3.4.2-3-IP3, the applicant applied Note G and identified the loss of material as the aging effect for aluminum valve bodies exposed to outdoor air (external) and proposed External Surfaces Monitoring Program to manage the effects of aging. The staff's evaluation of the External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.5. The staff finds this acceptable because the GALL Report has the same material/environment/aging effect/aging management program for different components in GALL Chapter III, Line Items III.B.2-7 and III.4-7.

In LRA Table 3.4.2-3-IP3, the applicant applied Note G and identified the loss of material as the aging effect for copper alloy tubing exposed to steam (internal) and proposed the Water Chemistry Control – Primary and Secondary to manage this aging effect. The staff's review of Water Chemistry Control – Primary and Secondary Program is documented in SER Section 3.0.3.2.17. Based on the review of this program, the staff finds the proposed program acceptable for managing loss of material due to exposure to steam (internal) because ASM Handbook, Volume 13B, "Corrosion of Metals," page 138, 2005 states that steam is not corrosive to copper alloys as long as levels of carbon dioxide, oxygen, and ammonia remain low. These species will be controlled by the Water Chemistry Control – Primary and Secondary to manage this aging effect.

In LRA Table 3.4.2-3-IP3, the applicant applied Note G and plant-specific Note 402 to carbon steel piping externally exposed to condensation with an aging effect of loss of material. Note 402 states, "[t]his environment is inside the condensate storage tank [CST]. The tank vapor space is nitrogen blanketed but the environment is conservatively assumed to be condensation." The applicant proposed the Water Chemistry Control – Primary and Secondary Program to manage the effects of aging. The staff's review of Water Chemistry Control – Primary and Secondary Program is documented in SER Section 3.0.3.2.17. The staff's evaluation of this component/material/environment/aging effect/AMP combination is documented in SER Section 3.4A.2.3.3. As stated in that section, the staff finds the applicant's AMR results acceptable.

In LRA Table 3.4.2-3-IP3, the applicant proposed using the One-Time Inspection Program to manage the loss of material in stainless steel tubing and valve bodies exposed to treated water (internal) environment. The applicant applied Note G and plant-specific Note 407 to indicate that the environment for these components and material is not included in the GALL Report. The staff finds that the applicant's One-Time Inspection Program will use inspections to detect whether these components are incurring a loss of material. The program uses both visual and NDE techniques for inspection. The program includes a provision that any unacceptable results or findings will be evaluated in accordance with the site corrective action process to determine the need for subsequent (including periodic) inspections. The staff evaluates the External Surfaces Monitoring Program in SER Section 3.0.3.1.9. Based on the above, the staff finds that the aging effect of the loss of material in these components will be adequately managed by using the One-Time Inspection Program.

In LRA Table 3.4.2-3-IP3, the applicant applied Note G and plant-specific Note 407, and identified the loss of material as the aging effect for carbon steel piping and valve bodies exposed to the treated water (internal) environment. The applicant has credited the Periodic Surveillance and Preventive Maintenance Program with managing this aging effect. The staff reviewed and evaluated the proposed Periodic Surveillance and Preventive Maintenance Program and documents its evaluation in SER Section 3.0.3.3.7. The program includes activities to monitor components to detect degradation and monitor parameters such as wall thickness and surface condition. The program uses both visual and NDE techniques to perform inspections. Based on the review of this program, the staff finds the proposed program acceptable for managing the loss of material in steel piping and piping components such as valve bodies.

In LRA Table 3.4.2-3-IP3, the applicant applied Note H and identified "cracking–fatigue" as the aging effect for stainless steel tubing exposed to steam (internal). Note H indicates that the aging effect is not identified in the GALL Report for the component/material/environment combination. The staff's evaluation of the metal fatigue TLAAs is documented in SER Section 4.3.2. During an audit, the staff questioned the applicant about these AMR results, to gain a better understanding of the conditions and how cracking would be managed (Audit Item 232). In its response, dated December 18, 2007, the applicant provided additional explanation of the conditions potentially leading to cracking and the consequences of a crack on performance of intended function. The staff reviewed this information and concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences. On this basis, the staff finds the applicant's AMR results to be acceptable for these combinations.

In LRA Table 3.4.2-3-IP3, the applicant applied Note H and identified "cracking–fatigue" as the aging effect for stainless steel flex hose, strainer, tubing, and valve body exposed to steam (internal). The applicant stated that this is a TLAA. Note H indicates that the aging effect is not identified in the GALL Report for the component/material/environment combination. The staff's evaluation of the metal fatigue TLAAs is documented in SER Section 4.3.2. During an audit, the staff questioned the applicant about these AMR results, to gain a better understanding of the conditions and how cracking would be managed (Audit Item 232). In its response, dated December 18, 2007, the applicant provided additional explanation of the conditions potentially leading to cracking and the consequences of a crack on performance of intended function. The staff reviewed this information and concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences. On this basis, the staff finds the applicant's AMR results to be acceptable for these combinations.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of combinations of material, environment, AERM, and AMP 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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4B.2.3.4 Steam Generator Blowdown System—Summary of Aging Management Review—LRA Table 3.4.2-4-IP3

The staff reviewed LRA Table 3.4.2-4-IP3, which summarizes the results of AMR evaluations for the SG blowdown system component groups.

In LRA Table 3.4.2-4-IP3, the applicant used Note I and identified no aging effect for the carbon steel bolting, piping, and valve bodies externally exposed to the plant indoor air environment. Note I for these AMR lines is further supplemented by the plant-specific Note 401 which implies that the applicable components are not subject to moisture condensation because they remain at high temperatures during normal plant operation. The components have a similar material and environment as Item SP-1 in the GALL Report, which is applicable to the steel piping, piping components, and piping elements in an external environment of indoor air and does not require an AEM or AMP. On the basis that the LRA components are similar to other GALL Report items for the material and environment (e.g., GALL Report, Volume 2, Table V.F, Line Item V.F-16, whereby the AERM is listed as "none," the AMP is listed as "none," and no further evaluation is required), the staff finds that the effect of plant indoor air on steel components at elevated temperatures will not result in aging that will be of concern during the period of extended operation.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of combinations of material, environment, AERM, and AMP 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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the steam and power conversion system components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5 Aging Management of Containments, Structures, and Component Supports

This section of the SER documents the staff's review of the applicant's AMR results for the containment, structure, and component support components and component groups of:

- containment building
- water control structures
- turbine building, auxiliary building, and other structures
- bulk commodities

3.5.1 Summary of Technical Information in the Application

LRA Section 3.5 provides AMR results for structures, structural components, and component supports. LRA Table 3.5.1, "Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.5.2 Staff Evaluation

The staff reviewed LRA Section 3.5 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for the containments, structures, and component supports components within the scope of license renewal and subject to an AMR, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff conducted onsite audits of AMRs to ensure the applicant's claim that certain AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's audit evaluation are documented in SER Section 3.5.2.1.

During the onsite audit, the staff also selected AMRs consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the SRP-LR Section 3.5.2.2 acceptance criteria. The staff's audit 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 structures and components which the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR line items and the plant's operating experience to verify the applicant's claims.

Table 3.5-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.5 and addressed in the GALL Report.

Table 3.5-1 Staff Evaluation for Structures, and Component Supports in the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
PWR Concrete (Reinforced and Prestressed) and Steel Containments					
Concrete elements: walls, dome, basemat, ring girder, buttresses, containment (as applicable). (3.5.1-1)	Aging of accessible and inaccessible concrete areas due to aggressive chemical attack, and corrosion of embedded steel	ISI (IWL) and for inaccessible concrete, an examination of representative samples of below-grade concrete, and periodic monitoring of groundwater if environment is non-aggressive. A plant specific program is to be evaluated if environment is aggressive.	Yes	Containment Inservice Inspection (CII) – IWL, and Structures Monitoring	Consistent with GALL Report after resolution of Open Item 3.5-1 (See SER Section 3.5.2.2.1)
Concrete elements; All (3.5.1-2)	Cracks and distortion due to increased stress levels from settlement	Structures Monitoring Program. If a 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 (See SER Section 3.5.2.2.1)
Concrete elements: foundation, sub-foundation (3.5.1-3)	Reduction in foundation strength, cracking, differential settlement due to erosion of porous concrete subfoundation	Structures Monitoring Program If a de-watering system is relied upon to control erosion of cement from porous concrete subfoundations, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes	Not applicable	Not applicable (See SER Section 3.5.2.2.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Concrete elements: dome, wall, basemat, ring girder, buttresses, containment, concrete fill-in annulus (as applicable) (3.5.1-4)	Reduction of strength and modulus of concrete due to elevated temperature	A plant-specific aging management program is to be evaluated.	Yes	Not applicable	Not applicable for IP3. Acceptable for IP2 after resolution of Open Item 3.5-2 (See SER Section 3.5.2.2.1)
Steel elements: drywell; torus; drywell head; embedded shell and sand pocket regions; drywell support skirt; torus ring girder; downcomers; liner plate, ECCS suction header, support skirt, region shielded by diaphragm floor, suppression chamber (as applicable) (3.5.1-5)	Loss of material due to general, pitting and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	Yes	Not applicable	Not applicable to PWRs (See SER Section 3.5.2.1.1)
Steel elements: steel liner, liner anchors, integral attachments (3.5.1-6)	Loss of material due to general, pitting and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	Yes	CII - IWE, Containment Leak Rate, and Structures Monitoring	Consistent with GALL Report (See SER Section 3.5.2.2.1)
Prestressed containment tendons (3.5.1-7)	Loss of prestress due to relaxation, shrinkage, creep, and elevated temperature	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	Not applicable	Not applicable (See SER Section 3.5.2.2.1)
Steel and stainless steel elements: vent line, vent header, vent line bellows; downcomers (3.5.1-8)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	Not applicable	Not applicable to PWRs (See SER Section 3.5.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel, stainless steel elements, dissimilar metal welds: penetration sleeves, penetration bellows; suppression pool shell, unbraced downcomers (3.5.1-9)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Consistent with GALL Report (See SER Section 3.5.2.2.1)
Stainless steel penetration sleeves, penetration bellows, dissimilar metal welds (3.5.1-10)	Cracking due to stress corrosion cracking	ISI (IWE) and 10 CFR Part 50, Appendix J, and additional appropriate examinations/ evaluations for bellows assemblies and dissimilar metal welds.	Yes	Not applicable	Not applicable (See SER Section 3.5.2.2.1)
Stainless steel vent line bellows, (3.5.1-11)	Cracking due to stress corrosion cracking	ISI (IWE) and 10 CFR Part 50, Appendix J, and additional appropriate examination/ evaluation for bellows assemblies and dissimilar metal welds.	Yes	Not applicable	Not applicable to PWRs (See SER Section 3.5.2.1.1)
Steel, stainless steel elements, dissimilar metal welds: penetration sleeves, penetration bellows; suppression pool shell, unbraced downcomers (3.5.1-12)	Cracking due to cyclic loading	ISI (IWE) and 10 CFR Part 50, Appendix J, and supplemented to detect fine cracks	Yes	CII - IWE and Containment Leak Rate	Consistent with GALL Report (See SER Section 3.5.2.2.1)
Steel, stainless steel elements, dissimilar metal welds: torus; vent line; vent header; vent line bellows; downcomers (3.5.1-13)	Cracking due to cyclic loading	ISI (IWE) and 10 CFR Part 50, Appendix J, and supplemented to detect fine cracks	Yes	Not applicable	Not applicable to PWRs (See SER Section 3.5.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Concrete elements: dome, wall, basemat ring girder, buttresses, containment (as applicable) (3.5.1-14)	Loss of material (scaling, cracking, and spalling) due to freeze-thaw	ISI (IWL). Evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index > 100 day-inch/yr) (NUREG-1557).	Yes	CII – IWL and Structures Monitoring	See SER Section 3.5.2.2.1
Concrete elements: walls, dome, basemat, ring girder, buttresses, containment, concrete fill-in annulus (as applicable). (3.5.1-15)	Cracking due to expansion and reaction with aggregate; increase in porosity, permeability due to leaching of calcium hydroxide	ISI (IWL) for accessible areas. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R.	Yes	CII – IWL and Structures Monitoring	See SER Section 3.5.2.2.1
Seals, gaskets, and moisture barriers (3.5.1-16)	Loss of sealing and leakage through containment due to deterioration of joint seals, gaskets, and moisture barriers (caulking, flashing, and other sealants)	ISI (IWE) and 10 CFR Part 50, Appendix J	No	CII – IWE and Containment Leak Rate	Consistent with GALL Report
Personnel airlock, equipment hatch and CRD hatch locks, hinges, and closure mechanisms (3.5.1-17)	Loss of leak tightness in closed position due to mechanical wear of locks, hinges and closure mechanisms	10 CFR Part 50, Appendix J and plant Technical Specifications	No	Containment Leak Rate, CII – IWE, and plant Technical Specifications	Consistent with GALL Report
Steel penetration sleeves and dissimilar metal welds; personnel airlock, equipment hatch and CRD hatch (3.5.1-18)	Loss of material due to general, pitting, and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	No	CII – IWE and Containment Leak Rate	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel elements: stainless steel suppression chamber shell (inner surface) (3.5.1-19)	Cracking due to stress corrosion cracking	ISI (IWE) and 10 CFR Part 50, Appendix J	No	Not applicable	Not applicable to PWRs (See SER Section 3.5.2.1.1)
Steel elements: suppression chamber liner (interior surface) (3.5.1-20)	Loss of material due to general, pitting, and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	No	Not applicable	Not applicable to PWRs (See SER Section 3.5.2.1.1)
Steel elements: drywell head and downcomer pipes (3.5.1-21)	Fretting or lock up due to mechanical wear	ISI (IWE)	No	Not applicable	Not applicable to PWRs (See SER Section 3.5.2.1.1)
Prestressed containment: tendons and anchorage components (3.5.1-22)	Loss of material due to corrosion	ISI (IWL)	No	Not applicable	Not applicable to IP (See SER Section 3.5.2.1.1)
Safety-Related and Other Structures; and Component Supports					
All Groups except Group 6: interior and above grade exterior concrete (3.5.1-23)	Cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring Program	Yes	CII – IWL and Structures Monitoring	Consistent with GALL Report (See SER Section 3.5.2.2.2)
All Groups except Group 6: interior and above grade exterior concrete (3.5.1-24)	Increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring Program	Yes	CII – IWL, supplemented by Structures Monitoring	Consistent with GALL Report (See SER Section 3.5.2.2.2)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
All Groups except Group 6: steel components: all structural steel (3.5.1-25)	Loss of material due to corrosion	Structures Monitoring Program. If protective coatings are relied upon to manage the effects of aging, the Structures Monitoring Program is to include provisions to address protective coating monitoring and maintenance.	Yes	Structures Monitoring, supplemented by Fire Protection	Consistent with GALL Report (See SER Section 3.5.2.2.2)
All Groups except Group 6: accessible and inaccessible concrete: foundation (3.5.1-26)	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring Program. Evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index > 100 day-inch/yr) (NUREG-1557).	Yes	CII – IWL, supplemented by Structures Monitoring. In some cases, Structures Monitoring is supplemented by Fire Protection	See SER Section 3.5.2.2.2
All Groups except Group 6: accessible and inaccessible interior/exterior concrete (3.5.1-27)	Cracking due to expansion due to reaction with aggregates	Structures Monitoring Program. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R-77.	Yes	CII – IWL, supplemented by Structures Monitoring.	See SER Section 3.5.2.2.2
Groups 1-3, 5-9: All (3.5.1-28)	Cracks and distortion due to increased stress levels from settlement	Structures Monitoring Program. If a 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 (See SER Section 3.5.2.2.2)
Groups 1-3, 5-9: foundation (3.5.1-29)	Reduction in foundation strength, cracking, differential settlement due to erosion of porous concrete subfoundation	Structures Monitoring Program. If a 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 (See SER Section 3.5.2.2.2)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Group 4: radial beam seats in BWR drywell; RPV support shoes for PWR with nozzle supports; steam generator supports (3.5.1-30)	Lock-up due to wear	ISI (IWF) or Structures Monitoring Program	Yes	Inservice Inspection (ISI) – IWF	Consistent with GALL Report (See SER Section 3.5.2.2.2)
Groups 1-3, 5, 7-9: below-grade concrete components, such as exterior walls below grade and foundation (3.5.1-31)	Increase in porosity and permeability, cracking, loss of material (spalling, scaling), aggressive chemical attack; cracking, loss of bond, and loss of material (spalling, scaling), corrosion of embedded steel	Structures Monitoring Program; examination of representative samples of below-grade concrete, and periodic monitoring of groundwater, if the environment is non-aggressive. A plant specific program is to be evaluated if environment is aggressive.	Yes	Structures Monitoring	See SER Section 3.5.2.2.2
Groups 1-3, 5, 7-9: exterior above and below grade reinforced concrete foundations (3.5.1-32)	Increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide	Structures Monitoring Program for accessible areas. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R-77.	Yes	Structures Monitoring	See SER Section 3.5.2.2.2
Groups 1-5: concrete (3.5.1-33)	Reduction of strength and modulus due to elevated temperature	A plant-specific aging management program is to be evaluated	Yes	Structures Monitoring	Not applicable (See SER Section 3.5.2.2.2)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Group 6: concrete; all (3.5.1-34)	Increase in porosity and permeability, cracking, loss of material due to aggressive chemical attack; cracking, loss of bond, loss of material due to corrosion of embedded steel	Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance programs and for inaccessible concrete, an examination of representative samples of below-grade concrete, and periodic monitoring of groundwater, if the environment is non-aggressive. A plant specific program is to be evaluated if environment is aggressive.	Yes	Structures Monitoring	See SER Section 3.5.2.2.2
Group 6: exterior above and below grade concrete foundation (3.5.1-35)	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance programs. Evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index > 100 day-inch/yr) (NUREG-1557).	Yes	Structures Monitoring	See SER Section 3.5.2.2.2
Group 6: all accessible and inaccessible reinforced concrete (3.5.1-36)	Cracking due to expansion/reaction with aggregates	Accessible areas: Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance programs. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R-77.	Yes	Structures Monitoring	See SER Section 3.5.2.2.2

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Group 6: exterior above and below grade reinforced concrete foundation interior slab (3.5.1-37)	Increase in porosity and permeability, loss of strength due to leaching of calcium hydroxide	For accessible areas, Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance programs. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R-77.	Yes	Structures Monitoring	See SER Section 3.5.2.2.2
Groups 7, 8: tank liners (3.5.1-38)	Cracking due to stress corrosion cracking; loss of material due to pitting and crevice corrosion	A plant-specific aging management program is to be evaluated	Yes	Not applicable	Not applicable (See SER Sections 3.5.2.1.2 and 3.5.2.2.2)
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-39)	Loss of material due to general and pitting corrosion	Structures Monitoring Program	Yes	Structures Monitoring, supplemented by Fire Protection and Fire Water System	Consistent with GALL Report (See SER Section 3.5.2.2.2)
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates (3.5.1-40)	Reduction in concrete anchor capacity due to local concrete degradation, service-induced cracking or other concrete aging mechanisms	Structures Monitoring Program	Yes	Structures Monitoring	See SER Section 3.5.2.2.2
Vibration isolation elements (3.5.1-41)	Reduction or loss of isolation function, radiation hardening, temperature, humidity, sustained vibratory loading	Structures Monitoring Program	Yes	Not applicable	Not applicable (See SER Sections 3.5.2.1.3 and 3.5.2.2.2)
Groups B1.1, B1.2, and B1.3: support members: anchor bolts, welds (3.5.1-42)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	Not applicable	Not applicable (See SER Section 3.5.2.2.2)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Groups 1-3, 5, 6: all masonry block walls (3.5.1-43)	Cracking due to restraint shrinkage, creep, and aggressive environment	Masonry Wall Program	No	Masonry Wall, supplemented by Fire Protection in some cases	Consistent with GALL Report
Group 6: elastomer seals, gaskets, and moisture barriers (3.5.1-44)	Loss of sealing due to deterioration of seals, gaskets, and moisture barriers (caulking, flashing, and other sealants)	Structures Monitoring Program	No	Structures Monitoring	Consistent with GALL Report
Group 6: exterior above and below grade concrete foundation; interior slab (3.5.1-45)	Loss of material due to abrasion, cavitation	Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance	No	Structures Monitoring	Consistent with GALL Report
Group 5: fuel pool liners (3.5.1-46)	Cracking due to stress corrosion cracking; loss of material due to pitting and crevice corrosion	Water Chemistry and monitoring of spent fuel pool water level in accordance with technical specifications and leakage from the leak chase channels.	No	Water Chemistry Control – Primary and Secondary, and Technical Specifications (for IP3 only)	Consistent with GALL Report
Group 6: all metal structural members (3.5.1-47)	Loss of material due to general (steel only), pitting and crevice corrosion	Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance. If protective coatings are relied upon to manage aging, protective coating monitoring and maintenance provisions should be included.	No	Structures Monitoring	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Group 6: earthen water control structures - dams, embankments, reservoirs, channels, canals, and ponds (3.5.1-48)	Loss of material, loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, Seepage	Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance programs	No	Not applicable	Not applicable to IP (See SER Section 3.5.2.1.4)
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-49)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and ISI (IWF)	No	Not applicable	Not applicable to PWRs (See SER Section 3.5.2.1.1)
Groups B2, and B4: galvanized steel, aluminum, stainless steel support members; welds; bolted connections; support anchorage to building structure (3.5.1-50)	Loss of material due to pitting and crevice corrosion	Structures Monitoring Program	No	Structures Monitoring	Consistent with GALL Report
Group B1.1: high strength low-alloy bolts (3.5.1-51)	Cracking due to stress corrosion cracking; loss of material due to general corrosion	Bolting Integrity	No	Not applicable	Not applicable (See SER Section 3.5.2.1.5)
Groups B2, and B4: sliding support bearings and sliding support surfaces (3.5.1-52)	Loss of mechanical function due to corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads	Structures Monitoring Program	No	Structures Monitoring	See SER Section 3.5.2.1
Groups B1.1, B1.2, and B1.3: support members: welds; bolted connections; support anchorage to building structure (3.5.1-53)	Loss of material due to general and pitting corrosion	ISI (IWF)	No	Inservice Inspection (ISI) – IWF	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Groups B1.1, B1.2, and B1.3: constant and variable load spring hangers; guides; stops; (3.5.1-54)	Loss of mechanical function due to corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads	ISI (IWF)	No	ISI – IWF	See SER Section 3.5.2.1
Steel, galvanized steel, and aluminum support members; welds; bolted connections; support anchorage to building structure (3.5.1-55)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	No	Boric Acid Corrosion Prevention	Consistent with GALL Report
Groups B1.1, B1.2, and B1.3: sliding surfaces (3.5.1-56)	Loss of mechanical function due to corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads	ISI (IWF)	No	ISI – IWF	Consistent with GALL Report
Groups B1.1, B1.2, and B1.3: vibration isolation elements (3.5.1-57)	Reduction or loss of isolation function, radiation hardening, temperature, humidity, sustained vibratory loading	ISI (IWF)	No	Not applicable	Not applicable to IP (See SER Section 3.5.2.1.3)
Galvanized steel and aluminum support members; welds; bolted connections; support anchorage to building structure exposed to air - indoor uncontrolled (3.5.1-58)	None	None	No	None	Consistent with GALL Report
Stainless steel support members; welds; bolted connections; support anchorage to building structure (3.5.1-59)	None	None	No	None	Consistent with GALL Report

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

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 structures, structural components, and component supports:

- Boric Acid Corrosion Prevention Program
- Containment Leak Rate Program
- Containment Inservice Inspection Program (CII-IWE)
- Containment Inservice Inspection Program (CII-IWL)
- Fire Protection Program
- Fire Water System Program
- Inservice Inspection Program – IWF
- Masonry Wall Program
- Periodic Surveillance and Preventive Maintenance Program
- Structures Monitoring Program
- Water Chemistry Control - Primary and Secondary Program

LRA Tables 3.5.2-1 through 3.5.2-4 summarize the results of the AMRs for the structures, structural components, and component supports, and identify the AMRs which the applicant claims are consistent with the GALL Report. The staff's review of LRA Tables 3.5.2-1 through 3.5.2-4, also included review of the revised LRA Tables 3.5.2-2 and 3.5.2-4 items in Attachment 1 to letter (Amendment 3 to LRA) dated March 24, 2008; and the revised LRA Table 3.5.2-1 items in Attachment 1 to letter (Amendment 5 to LRA) dated June 11, 2008.

For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the report, where the report 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.

For each AMR line item, the applicant stated how the information in the tables aligns with the information in the GALL Report. Notes A through E indicate how the AMR is consistent with the GALL Report. The staff audited these AMRs.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report and validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report and verified that the identified exceptions to the GALL Report AMPs have been reviewed and accepted. The staff also determined whether the applicant's AMP was consistent with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the 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 line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review and whether the identified exceptions to the GALL Report AMPs have been reviewed and accepted. The staff also determined whether the applicant's AMP was consistent with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but credits a different AMP. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the credited AMP would manage the aging effect consistently with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

The staff audited and reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs.

The staff reviewed the AMRs in LRA Tables 3.5.2-1 through 3.5.2-4 that reference notes A through D, in order to confirm that the applicant: (a) provided a brief description of the system, components, materials, and environments; (b) stated that the applicable aging effects were reviewed and evaluated in the GALL Report; and (c) identified those aging effects for the structures, structural components, and component supports that are subject to an AMR. On the basis of its audit and review, the staff determined that, for AMRs not requiring further evaluation, as identified in LRA Table 3.5.1, the applicant's references to the GALL Report are acceptable and no further staff review is required, with two (2) exceptions which are discussed below.

LRA Table 3.5.1, Item 3.5.1-52, Groups B2, and B4: sliding support bearings and sliding support surfaces, identifies "Loss of mechanical function due to corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads" as the aging effect/mechanism. The applicant's entry under Discussion is "Loss of mechanical function due to the listed mechanisms is not an aging effect. Such failures typically result from inadequate design or operating events rather than from the effects of aging. Failures due to cyclic thermal loads are rare for structural supports due to their relatively low temperatures."

During the on-site audit and review, the staff questioned the applicant as to whether Group B2 and B4 supports that have a mechanical function, in addition to a structural support function, are included in the applicant's Structures Monitoring Program, and are inspected for signs of any type of degradation. The applicant indicated this is the case. Although the applicant does not consider the loss of mechanical function due to the listed mechanisms to be an aging effect for these items, the applicant has an AMP which monitors for this aging effect/component combination. On the basis that the applicant has an acceptable program in place to manage loss of mechanical and structural support functions for Group B2 and B4 supports, the staff determined that this combination will be adequately managed during the period of extended operation.

LRA Table 3.5.1, Item 3.5.1-54, Groups B1.1, B1.2, and B1.3: constant and variable load spring hangers; guides; stops, identifies "Loss of mechanical function due to corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads" as the "Aging Effect/Mechanism." The applicant's entry under "Discussion" is "Loss of mechanical function due to the listed mechanisms is not an aging effect. Loss of mechanical function due to distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads is not an aging effect requiring management. Such failures typically result from inadequate design or events rather than the effects of aging. Loss of material due to corrosion, which could cause loss of mechanical function, is addressed under Item 3.5.1-53 for Groups B1.1, B1.2, and B1.3 support members."

The staff questioned the applicant as to whether the ISI-IWF Program manages loss of mechanical function due to corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads, for Group B1.1, B1.2, and B1.3 ASME Code supports (Audit Item 250). In a letter dated December 18, 2007, the applicant stated that this is included in its ISI-IWF Program. Although the applicant does not consider the loss of mechanical function due to the listed mechanisms to be an aging effect for these items, the applicant has an AMP which monitors for this aging effect/component combination. On the basis that the applicant has an acceptable program in place to manage loss of mechanical function for Group B1.1, B1.2, and B1.3 ASME Code supports, the staff determined that this combination will be adequately managed during the extended period of operation.

The staff reviewed the AMR results in LRA Tables 3.5.2-1 through 3.5.2-4 that reference Note E.

For certain entries, the staff found that the applicant had referenced the AMPs that are credited in the GALL Report (IWL, IWE, IWF). However, the applicant chose to identify its AMPs for IWL, IWE, and IWF as plant-specific, rather than consistent with the GALL Report. Consequently, wherever these AMPs are credited, the applicant referenced Note E. This is acceptable, on the basis that the staff's review concluded that the applicant's AMPs are consistent with the corresponding GALL AMPs. The staff's detailed evaluations of the applicant's AMPs corresponding to IWL, IWE, and IWF are documented in SER Sections 3.0.3.3.2 through 3.0.3.3.4.

For entries that address cracking of masonry wall components, the applicant credits its Fire Protection Program, in addition to its Masonry Wall Program (which is consistent with the GALL Report), for aging management. The staff confirmed that these AMPs inspect for cracking of masonry wall components. The staff finds the applicant's AMR results to be acceptable.

For those entries that cover loss of material for carbon steel crane components, GALL Volume 2 Item VII B-3 (A-07) and Table 1, Item 3.3.1-73 is referenced. The applicant credits either the Periodic Surveillance and Preventive Maintenance Program or the Structures Monitoring Program. The staff confirmed that these AMPs inspect for loss of material of carbon steel components. The staff finds the applicant's AMR results to be acceptable.

Multiple entries cover loss of material for concrete and steel components of water control structures and related bulk commodities, exposed to either a fluid environment or air, and credit the Structures Monitoring Program. As discussed in the GALL Report, for water control structures, an applicant may credit its Structures Monitoring Program, in lieu of the RG 1.127 AMP described in the GALL Report, provided all elements of the GALL RG 1.127 AMP are incorporated in the applicant's Structures Monitoring Program. Entergy has chosen this approach, and the staff has confirmed that the applicant's Structures Monitoring Program, as revised in response to Audit Item 88, incorporates the elements of the GALL RG 1.127 AMP. Therefore, the staff finds the applicant's AMR results to be acceptable. The staff's detailed evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.15.

One entry covers loss of material for carbon steel roof decking in an indoor air (uncontrolled) environment. The applicant references Table 1 Item 3.5.1-25, and credits the Fire Protection AMP. The applicant has also credited the Structures Monitoring AMP in a separate Table 2 entry. Although the GALL report identifies the Structures Monitoring Program as the acceptable AMP, structural commodities related to plant fire protection are typically inspected under either the Fire Protection AMP or the Fire Water System AMP. For the specific applications cited above, the staff considers these AMPs to be acceptable alternatives or adjuncts to the Structures Monitoring AMP.

Two entries cover loss of material of stainless steel liner plates and gate, in the refueling canal and the spent fuel pool. The applicant references Table 1, Item 3.5.1-46, and credits the Water Chemistry Control – Primary and Secondary Program and monitoring of spent fuel pool level per technical specifications (spent fuel pool only). The staff found that the applicant's AMR result is consistent with the GALL Report for loss of material, but noted that the corresponding GALL Table 1 item also covers stress corrosion cracking of stainless steel liners. In LRA Table 1, Item 3.5.1-46, the applicant stated that the temperature threshold (140 °F) for the occurrence of stress corrosion cracking is higher than the operating temperature of the IP2 and IP3 spent fuel pools. Consequently, stress corrosion cracking is not an applicable aging effect. The staff confirmed that the operating temperature is lower than 140 °F. Therefore, the staff finds that stress corrosion cracking in the spent fuel liner is not an applicable aging effect.

In LRA Table 3.5.2-3, for spent fuel pool liner plate and gate (IP2), the applicant included Note E which means that the AMR line item is consistent with the GALL Report, but a different AMP is credited. The spent fuel pool at IP2 is not equipped with leak chase channels. The GALL Report indicates that the appropriate AMP for spent fuel pool liners is Water Chemistry Program as well as monitoring the pool level and leakage from the leak chase channels in accordance with technical specifications. The staff noted that LRA Table 3.5.1, Item 3.5.1-46 states that aging of the fuel pool liners will be managed by the water chemistry program and monitoring of spent fuel pool water level in accordance with Technical Specifications and leakage from the leak chase channel. The staff observed that the table included, in part, the following discussion, "Monitoring spent fuel pool water level in accordance with Technical Specifications and monitoring leakage from the leak chase channels (Unit 3) will also continue during the period of extended operation."

The staff noted that the monitoring program for IP2 differs from that specified for IP3 and from that credited in the GALL Report. The IP3 and GALL Report programs involve monitoring leakage from the leak chase channels. By letter dated January 28, 2008, the staff issued RAI 3.5A.2-1, requesting the applicant to explain whether the spent fuel pool water level may be insensitive to leakage comparable to the rate of evaporation and could be masked by routine makeup water additions. If spent fuel pool leakage could be masked by evaporation and routine water additions, the applicant was requested to describe how the proposed monitoring at IP2 would provide acceptable indication of a degrading liner or describe an alternative monitoring method (e.g., monitoring of nearby wells).

In its response to RAI 3.5A.2-1, dated February 27, 2008, the applicant stated that unlike the IP3 spent fuel pool, the IP2 spent fuel pool does not have leak chase channels. Therefore, no monitoring of leak chase channels can be performed for IP2. The monitoring of the spent fuel pool water level is credited along with the "Water Chemistry Control - Primary and Secondary Program" for managing the effects of aging on the IP2 spent fuel pool liner. The applicant added that routine makeup water additions to compensate for evaporative losses could mask leakage rates that are comparable to the rate of evaporation. However, leakage rates that could challenge the intended function of the spent fuel pool to maintain adequate inventory would be indicated by abnormal rates of level decrease and associated abnormal makeup requirements. In addition, the "Water Chemistry Control - Primary and Secondary Program" is an existing program that manages aging effects caused by corrosion and cracking mechanisms, which are potential causes of leakage. The applicant further stated that the program relies on monitoring and control of reactor water chemistry based on the EPRI guidelines in TR-105714, Rev. 5, Pressurized Water Reactor Primary Water Chemistry Guidelines, and TR-102134, Rev. 6, Pressurized Water Reactor Secondary Chemistry Guidelines. The applicant stated that the effectiveness of the "Water Chemistry Control – Primary and Secondary Program" at managing degradation of stainless steel in a borated water environment has been demonstrated in industry and IP operating experience. The applicant stated that the IP2 operating experience did include leaks that were not due to the effects of aging. The applicant stated that the cause of these leaks was poor workmanship during initial construction of the liner and the identified defects due to the initial poor workmanship have been repaired. In a later conference call, held August 27, 2008, in relation to Audit Question 360, the applicant stated that during a rerack in the early 1990s, damage occurred to the liner which caused a pin-hole leak. This pin-hole damage to the liner was subsequently repaired. In its response to RAI 3.5A.2-1, the applicant stated that monitoring wells in proximity to the IP2 spent fuel pool are used for continued monitoring to identify any potential recurrence of leaks.

The applicant is relying on monitoring at IP2 of water chemistry and spent fuel pool water level to provide indication of a degrading liner. However, due to the lack of a leak-chase channel and collection system at IP2 to monitor, detect and quantify leakage through the SFP liner and preclude its long-term accumulation behind the liner in a reliable manner during the period of extended operation, the staff finds that the effectiveness of Water Chemistry AMP in controlling liner degradation is more difficult to confirm. The applicant stated it was using monitoring wells in proximity to the IP2 spent fuel pool to identify potential leaks (Commitment 25). However, the staff had concerns about the effectiveness of the applicant's AMP to detect and manage the effects of potential leakage through the IP2 spent fuel pool liner during the period of extended operation. The staff's further evaluation and resolution of this issue is discussed in the resolution of Open Item 3.0.3.2.15-2 (Audit Item 360) in SER Section 3.0.3.2.15.

The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.1.1 AMR Results Identified as Not Applicable

LRA Table 3.5.1 Line Items 5, 8, 11, 13, 19, 20, 21, and 49 are identified as "Not Applicable" because they apply only to BWR containments. The staff confirmed that the applicant identified the correct items as being not applicable for this reason. The following additional items, discussed in SER Sections 3.5.2.1.2 thru 3.5.2.1.5, were also identified as not applicable by the applicant. The staff confirmed the applicant's conclusions.

LRA Table 3.5.1 Line Item 22 addresses prestressed containment tendons and anchorage components. The applicant stated that this line item does not apply to IP because neither the IP2 nor IP3 has a prestressed concrete containment. The IP containments are steel-lined, reinforced concrete. The staff confirmed the design of the containments based upon information in the IP2 and IP3 UFSARs. Therefore, the staff finds that this line item is not applicable to IP.

3.5.2.1.2 Tank Liners of Stainless Steel (LRA Table 3.5.1, Item 3.5.1-38)

There are no concrete or steel tanks with stainless steel liners within the scope of license renewal at IP.

3.5.2.1.3 Vibration Isolation Elements (LRA Table 3.5.1, Items 3.5.1-41 and 3.5.1-57)

There are no vibration isolation elements within the scope of license renewal at IP.

3.5.2.1.4 Earthen Water Control Structures (LRA Table 3.5.1, Item 3.5.1-48)

IP does not have earthen water control structures.

3.5.2.1.5 Group B1.1 High Strength Low-Alloy Bolts (LRA table 3.5.1, Item 3.5.1-51)

IP does not have high tensile strength bolting as defined by yield strength > 150 KSI or low alloy steel bolts (SA 193 Grade B7) used for NSSS component supports.

The staff evaluated the applicant's claim that certain GALL Report items do not apply to Indian Point. The staff reviewed information from the UFSAR to confirm that the identified component types do not exist at Indian Point. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed do not apply, are not applicable.

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 structure and component support components and provides information concerning how it will manage aging effects in the following three areas:

(1) PWR and BWR containments:

- aging of inaccessible concrete areas
- cracks and distortion due to increased stress levels from settlement; reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations if not covered by the Structures Monitoring Program
- reduction of strength and modulus of concrete structures due to elevated temperature
- loss of material due to general, pitting, and crevice corrosion
- loss of prestress due to relaxation, shrinkage, creep, and elevated temperature
- cumulative fatigue damage
- cracking due to SCC
- cracking due to cyclic loading
- loss of material (scaling, cracking, and spalling) due to freeze-thaw
- cracking due to expansion and reaction with aggregate and increase in porosity and permeability due to leaching of calcium hydroxide

(2) safety-related and other structures and component supports:

- aging of structures not covered by the Structures Monitoring Program
- aging management of inaccessible areas
- reduction of strength and modulus of concrete structures 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
- aging of supports not covered by the Structures Monitoring Program
- cumulative fatigue damage due to cyclic loading

(3) QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the report and for which the report recommends further evaluation, the staff audited and reviewed the applicant’s evaluation to determine whether it adequately addressed the issues further evaluated. 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 Containment Structures

The staff reviewed LRA Section 3.5.2.2.1 against the criteria in SRP-LR Section 3.5.2.2.1.

Aging of Inaccessible Concrete Areas. The staff reviewed LRA Section 3.5.2.2.1.1 using the review procedures of SRP-LR Section 3.5.3.2.1.1. The inaccessible areas in IP2 and IP3 containment structures are primarily the below grade areas of the structures.

In LRA Section 3.5.2.2.1.1, the applicant stated that concrete in accessible and inaccessible areas is in accordance with American Concrete Institute (ACI) specification ACI 318, "Building Code Requirements for Reinforced Concrete," for low permeability and resistance to aggressive chemical attack because of the following requirements:

- high cement content
- low water-to-cement ratio
- proper curing
- adequate air entrainment

The applicant stated that IP concrete also meets the requirements of the later ACI 201.2R-77, "Guide to Durable Concrete," as both specifications use the same ASTM standards for concrete selection, application, and testing. The below-grade environment is not aggressive (pH > 5.5, chlorides < 500 ppm, and sulfates < 1,500 ppm). According to the applicant concrete air content was at least the required minimum of between 4 and 6 percent and water-to-cement ratios were in accordance with the ACI 318 version for IP construction, which allows a ratio of up to 0.576 (for non air-entrained concrete) for concrete with the compressive strength specified for IP. The applicant also stated that although specified water-to-cement ratios fall outside the established range of 0.35 to 0.45 of the GALL Report, IP concrete meets ACI specifications for acceptable concrete quality. The applicant concluded that an increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack and cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel are not applicable for concrete in inaccessible areas. The applicant credited the Containment Inservice Inspection and Structures Monitoring programs to confirm the absence of concrete aging effects.

SRP-LR Section 3.5.3.2.1.1 states that the GALL Report recommends further evaluation of programs to manage aging effects in inaccessible areas of concrete if the environment is aggressive. Possible aging effects are increases in porosity and permeability, cracking and loss of material (spalling, scaling) due to aggressive chemical attack and cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel in PWR and BWR concrete and steel containments. The current aging management program for concrete containments is Section XI Subsection IWL examinations, in accordance with the requirements of 10 CFR 50.55a. However, Subsection IWL exempts from examination portions of the concrete containments that are inaccessible (e.g., foundation, exterior walls below grades, concrete covered by liner).

For the inaccessible areas, 10 CFR 50.55a(b)(2)(ix) requires that the applicant evaluate 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. In addition, the GALL Report recommends further evaluation to manage these aging effects for inaccessible areas if the below-grade environment is aggressive. Periodic monitoring of below-grade water chemistry (including consideration of potential seasonal variations) is an acceptable approach to demonstrate that the below-grade environment is aggressive or non-aggressive. The GALL Report recommends that examination of representative samples of below-grade concrete, when excavated for any reason, be performed.

The staff noted a discrepancy in the applicant's description of the containment concrete properties in LRA Section 3.5.2.2.1.1 which references ACI 318 for the concrete mix design. The staff confirmed that the 1963 edition of ACI 318 is the code of record for IP2 and IP3, and the design compressive strength of concrete is 3000 psi. The discrepancy was that the applicant referenced an inconsistent combination of air entrainment and water-cement ratio corresponding to its design compressive strength. Per Table 502(a) of ACI 318-63, for 3000 psi concrete, the water-cement ratio may be as high as 0.576 if there is no air entrainment. With air entrainment of four to six percent, as identified in LRA Section 3.5.2.2.1.1, the maximum water-cement ratio should be 0.465. Since the applicant claimed that the relevant aging effects of inaccessible concrete areas are not applicable because the IPEC concrete meets specifications and quality standards of ACI 318-63 and ACI 201.2R-77, in a telephone conference call dated September 3, 2008, the staff asked the applicant to clarify if the correct value should be 0.465, and also to describe how its concrete mix meets ACI 318-63 specifications. By letter dated November 6, 2008, the applicant stated that ACI 318-63 provides two methods for determination of concrete properties which will result in the required concrete strength. The applicant stated that IP used method 2, which involves testing concrete trial mixes to establish a water-cement ratio that provides the required quality. The applicant further stated that the concrete mixture at IP was established based on tests of concrete mixtures and actual tests for containment concrete showed compressive strengths above the required 3000 psi. At the time of issuance of the SER with Open Items, the staff was in the process of reviewing the applicant's response. Thus, this issue was identified as Open Item 3.5-1.

The staff also noted that the applicant states in the LRA that the concrete meets the requirements of later ACI guide ACI 201.2R-77 since both documents use the same ASTM standards for selection, application and testing of concrete. During the phone call of September 3, 2008, the staff asked the applicant to clarify the use of the later ACI 201.2R-77 since the editions of the ASTM standards may have changed between 1963 and 1977. In its letter dated November 6, 2008, the applicant stated that IP structures designed in accordance with ACI 318-63 align with many of the recommendations in ACI 201.2R-77. As mentioned above, the staff was in the process of reviewing the applicant's response when the SER with Open Items was issued. Therefore, this issue was identified as part of Open Item 3.5-1.

The staff reviewed the applicant's response dated November 6, 2008, and determined that the staff required additional clarifications related to satisfaction of the GALL Report criteria for establishing concrete durability, and the applicant's claim that there are no applicable concrete aging effects requiring management.

In an effort to resolve this open item, the staff issued follow-up RAI 4: Open Item 3.5-1, dated April 3, 2009, which requested the following information:

a. In the clarification to LRA Section 3.5.2.2 (Part 1) on page 6 of Attachment 1 to letter NL-08-169, the applicant stated that it used Method

2 of Section 502 of ACI 318-63 by testing trial mixes to determine the water-cement ratios for the concrete mix design of the IP containments and other structures. In order for the staff to evaluate the quality and durability of concrete in IP structures that may be subject to degradation during the period of extended operation, the staff requests the applicant to define the water-cement ratio that was used at the time of construction. Additionally, to assist the staff in understanding the parameters related to concrete strength and durability during the period of extended operation, the applicant is requested to describe the methodology used to establish the required concrete compressive strength of 3000 psi for the containment and other safety-related concrete structures, in accordance with ACI 318- 63, Method 2. The applicant is requested to provide a summary of the results of statistical analyses performed, if any, of the original concrete strength tests, including number of samples, raw strength values from the test, the mean, the standard deviation, and the original criterion (e.g., mean minus 1 standard deviation, coefficient of variation) used to confirm that the required compressive strength was achieved. The applicant is requested to provide this information for the IP containments and other safety-related IP Unit 2 and 3 concrete structures, including the refueling cavities and the spent fuel pools, to support the applicant's view that IP concrete meets the requirements of Method 2 in Section 502 of ACI 318-63 and the intent of ACI 201.2R-77.

b. If the applicant is unable to provide the information requested in part (a) above, the applicant is requested to explain how the aging effects on concrete will be adequately managed and safety margins will be determined during the period of extended operation.

By letter dated May 1, 2009, Entergy responded to follow-up RAI 4: Open Item 3.5-1 stating that:

> Pour data samples taken during construction show water-to-cement ratio used at IPEC ranged from a low of 0.488 (equipment hatch area) to a high-of 0.611 (containment el. 68') with an average ratio at the time of construction of 0.534. The method used to confirm the required concrete compressive strength of 3000 psi for the containment and other safety-related concrete structures, in accordance with ACI 318-63, Method 2 is testing of actual field samples taken during construction. ACI documents state that strength and durability are primarily governed by water-to-cement (w/c) ratio, and strength goes hand-in-hand with durability. The strength and durability are both based on the permeability of the concrete which is based on the distance between the cement particles, i.e., the closer the cement particles the stronger the concrete. Permeability is therefore a function of the w/c ratio, particle size distribution (PSD), type of cement, type of aggregate, compaction and quality control. Relying on just one indicator for durability is not justified, which is why the ACI code uses it only as a first estimate based on the tables for determining strength and durability. The ACI documents recommend that the strength based on w/c ratio should be verified by trial batches to ensure the specified properties of the concrete are met. To confirm that the required compressive strength was achieved, ACI 214.3R-88, "Simplified Version of the Recommended Practice for

Evaluation of Strength Test Results of Concrete" was used to develop a summary of the results of the original concrete strength tests. These results are based on raw strength values from the test samples to obtain the mean and the standard deviation.

IPEC containment and other safety-related structures were designed for a minimum compressive strength of 3000 psi. A total pour of approximately 20,000 cubic yards was expected. Therefore, in order to ensure this design parameter was achieved, an average design margin of 15% above this minimum was also specified.

Approximately 200 concrete test reports for concrete used in IP containment, refueling cavity and spent fuel pool area were reviewed. Air entrainment values ranged between 3.5 and 6.5%. Only a few of the test reports indicated air entrainment higher than 6.0%. Those values are acceptable based on the ACI 211.1-77 section 5.3.3 which shows that higher entrainment values up to 7% are acceptable for extreme exposure conditions; higher air entrainment is generally better for durability. A primary concern for high air entrainment is an accompanying reduction in concrete strength. As discussed in the following paragraph, the concrete used for IP containment, refueling cavity and spent fuel pool still exceeded the concrete design strength requirements in accordance with ACI 318-63 producing durable, low permeability concrete.

Each concrete test report involved an average of 3 sample concrete cylinders for strength testing. No test cylinder strength under 3000 psi 28-day strength was observed. The compressive strength from these samples ranged from a low of 3436 psi (containment exterior wall el. 68'-73') to 5393 psi (containment ring area) with an extreme of 6410 psi (containment equipment hatch area). The standard deviation obtained from the samples reviewed was determined to be approximately 670 psi with an average or mean concrete compressive strength of approximately 4050 psi. Based on this actual concrete test data, the required concrete compressive strength of 3000 psi for the containment and other safety-related concrete structures, in accordance with ACI 318-63, Method 2 was achieved with no sample below one standard deviation from the mean. Although this identifies that IPEC concrete is of good quality, the credited programs in Appendix B of the application will confirm the absence of significant concrete aging effects.

The applicant further stated that no response is required to part (b) of RAI 4, because the information requested in part (a) was provided.

The staff reviewed the applicant's response to follow-up RAI 4: Open Item 3.5-1 dated May 1, 2009, and found that the average, minimum, and maximum strength of concrete used in the IP containments, refueling cavities and spent fuel pools at 28 days was 4050, 3436, and 5393 psi respectively. This is based on a sample of 200 tests performed on concrete samples collected during construction of IP. The design of the IP containments and other safety-related structures is based on a minimum compressive strength of 3000 psi at 28 days.

Based on the test results, the staff concludes that there is a sufficient documented basis to provide reasonable assurance that IP concrete meets the ACI standards for strength. Inasmuch as the applicant has demonstrated that the compressive strength of the concrete exceeds the required strength of 3000 psi, the staff's previous concern with respect to the water-cement ratio is resolved. The staff concludes that the periodic inspections conducted under the Containment ISI - IWL Program and the Structures Monitoring Program will manage the aging of the IP concrete as required by 10 CFR 54.21(a)(3). Therefore, Open Item 3.5-1 is closed.

The staff noted that the applicant's "Further Evaluation" discussion in LRA 3.5.2.2.1.1 does not identify any commitments to monitor inaccessible areas. In response to a series of questions asked by the staff during the onsite audit and review, the applicant confirmed that its IWL inspection program is in accordance with the regulatory requirements in 10 CFR 50.55a, and includes provision to evaluate 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. The applicant also made the following two new license renewal commitments related to inaccessible concrete areas.

(1) The applicant has committed to a groundwater monitoring program that is sufficient in scope to assess the aggressiveness of the site groundwater to concrete on a periodic basis, as an enhancement of its Structures Monitoring AMP. (Commitment 25 in Regulatory Commitment List, Revision 5; Attachment 4 to Entergy letter dated August 14, 2008)

(2) The applicant has committed to inspect inaccessible concrete areas that are exposed by excavation for any reason, as an enhancement of its Structures Monitoring AMP. (Commitment 25 in Regulatory Commitment List, Revision 5; Attachment 4 to Entergy letter dated August 14, 2008)

Based on the programs and commitments identified above, the staff finds that the LRA section is consistent with the GALL Report and the recommendations in the SRP-LR and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Cracks and Distortion Due to Increased Stress Levels from Settlement; Reduction of Foundation Strength, Cracking, and Differential Settlement Due to Erosion of Porous Concrete Subfoundations, if Not Covered by the Structures Monitoring Program</u>. The staff reviewed LRA Section 3.5.2.2.1.2 using the review procedures of SRP-LR Section 3.5.3.2.1.2.

In LRA Section 3.5.2.2.1.2, the applicant stated that these aging effects are not applicable because (a) IP does not rely on a dewatering system for control of settlement, (b) structures are founded on bedrock, (c) IN 97-11 does not include IP in plants susceptible to porous concrete containment subfoundation erosion, and (d) the IP containment foundation does not use porous concrete.

SRP-LR Section 3.5.3.2.1.2 states that the GALL Report recommends aging management of (1) cracks and distortion due to increases in component stress level from settlement for PWR and BWR concrete and steel containments and (2) reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations for all types of PWR and BWR containments if not within the scope of structures monitoring program. Also, if a de-watering system is relied upon for control of settlement and erosion, then proper functioning of the de-watering system should be monitored for the period of extended operation.

The applicant stated that the aging effects due to settlement are not expected at IP for the containment building foundation. The containment building is founded on bedrock which would prevent significant settlement. In addition, there is no porous concrete subfoundation below the containment building of concern. Through review of the LRA and bases documents, the staff determined that the cracking and distortion due to increased stress levels from settlement; reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations are not applicable to IP.

On the basis that IP has no relevant aging effects, the staff concludes that these aging effects are not applicable.

<u>Reduction of Strength and Modulus of Concrete Structures Due to Elevated Temperature</u>. The staff reviewed LRA Section 3.5.2.2.1.3 using the review procedures of SRP-LR Section 3.5.3.2.1.3.

In LRA Section 3.5.2.2.1.3, the applicant stated that ACI 349 specifies long-term temperature limits of 150°F for general areas and 200°F for local areas. The effects of aging due to elevated temperature exposure are not significant below these temperatures.

The applicant also stated that the IP2 containment areas during normal operation are below 130°F bulk average temperature. Penetrations through the containment cylinder wall for pipes carrying hot fluid are cooled by air-to-air heat exchangers and the pipes are insulated to maintain the temperature in the adjoining concrete below 250°F. The GALL Report provides for local area concrete temperatures higher than 200°F if tests or calculations evaluate the reduction in strength. The applicant also states that an evaluation of IP2 hot piping penetration concrete has found temperatures up to 250°F acceptable.

The applicant further stated that the IP3 containment areas normally operate below a bulk average temperature of 130°F. Penetrations through the containment cylinder wall for pipes carrying hot fluid are cooled by air-to-air heat exchangers and the pipes are insulated to maintain the temperature in the adjoining concrete below 200°F.

The applicant concluded that there are no aging effects due to elevated temperature requiring management for the IP containment structures.

SRP-LR Section 3.5.3.2.1.3 states that the GALL Report recommends further evaluation of programs to manage reduction of strength and modulus of concrete structures due to elevated temperature for PWR and BWR concrete and steel containments. The GALL Report notes that the implementation of ASME Section XI, Subsection IWL examinations and 10 CFR 50.55a would not be able to detect the reduction of concrete strength and modulus due to elevated temperature and also notes that no mandated aging management exists for managing this aging effect. The GALL Report recommends that a plant-specific evaluation be performed if any portion of the concrete containment components exceeds specified temperature limits, i.e., general temperature greater than 66°C (150°F) and local area temperature greater than 93°C (200°F).

Since the concrete temperature limits in the GALL report are not exceeded for IP3, the staff finds that the reduction of strength and modulus due to elevated temperature are not aging effects requiring management for IP3.

The staff's review of operating experience did not identify any occurrences of concrete degradation at the IP2 hot penetrations. However, because concrete degradation at elevated temperatures is a slow process, there is a need to confirm that an additional 20 years of operation will not lead to significant degradation. As stated above, the GALL Report recommends that a plant-specific evaluation be performed if any portion of the concrete containment components exceeds specified temperature limits. During a teleconference call held on September 3, 2008, the staff asked the applicant what the effects on the concrete properties (strength, modulus of elasticity) will be during the period of extended operation for areas where the local temperature exceeds 93°C (200°F). By letter dated November 6, 2008, the applicant stated that an engineering evaluation of the effect of 250°F temperatures on the hot piping penetration concrete was performed. The evaluation determined that a reduction in strength of 15% could be expected from the elevated temperatures. The applicant further stated that this reduction in strength was acceptable since the original concrete compressive strength tests showed an actual strength more than 15 percent higher than the design strength of 3000 psi. The applicant did not state how it addressed the reduction in modulus of elasticity and its effect in the evaluation. At the time of issuance of the SER with Open Items, the staff was in the process of reviewing the applicant's response; therefore, this issue was identified as Open Item 3.5-2.

The staff reviewed the applicant's response dated November 6, 2008, and concluded that the staff required additional clarifications before it could determine that the effects of elevated temperature on the IP2 containment structure had been adequately evaluated.

In an effort to resolve this open item, the staff issued follow-up RAI 5: Open Item 3.5-2, dated April 3, 2009, which requested the following information:

a. Clearly explain the role of the air-to-air heat exchangers in cooling the concrete around the hot piping penetrations. Include the normal operating temperature of the concrete as well as the maximum concrete temperature assuming failure of the heat exchangers.

b. In the clarification to LRA Section 3.5.2.2 (Part 3) on page 7 of Attachment 1 to letter NL-08-169, the applicant stated that a 15% reduction of concrete strength could be expected when reaching temperatures of 250ºF and that concrete compressive strength tests showed an actual strength more than 15% higher than design strength. Please provide the methodology used to arrive at the conclusion that the actual concrete strength is more than 15% greater than 3000 psi, (i.e., greater than 3450 psi). Provide a summary of the results, including number of samples, raw strength values from the test, the mean, the standard deviation, and the original criterion (e.g., mean minus 1 standard deviation) used to confirm that the claimed strength was achieved. Explain how consideration was given to the reduction in modulus of elasticity in the high temperature concrete evaluation.

c. If the applicant is unable to provide the information requested above, the applicant is requested to explain how the aging effects on concrete, due to high temperatures, will be adequately managed during the period of extended operation.

By letter dated May 1, 2009, Entergy responded to follow-up RAI 5: Open Item 3.5-2, in which it stated:

a. The air-to-air heat exchangers are discussed in IPEC 2 & 3 UFSAR Section 5.1.4.2.2 and Section 5.1.4 respectively. The function of the hot penetration cooling (HPC) system is to provide a cooling medium that will limit the temperature of the containment concrete surrounding a thermally hot penetrating line. Operating procedures require the system to be placed in service whenever RCS temperature is > 150 ^{o}F.

   The HPC system comprises two separate and non-interconnected subsystems. Each subsystem is composed of 2 positive displacement blowers, valves, air-to-air heat exchangers and connecting piping. Each of the subsystems blowers supplies air from outside the building to the air-to-air heat exchanger which cools the space between the process line insulation and the penetration sleeve. The air-to-air heat exchanger is made by welding together one flat sheet on one embossed sheet of 10-gauge carbon steel. The embossment forms the coolant channels, through which the HPC system air passes. The unit is rolled into the form of a cylinder with an outside diameter of the penetration sleeve and inside diameter that allows placement over the outside of the pipe insulation [The applicant referred to Figures 8 and 9 in the response]. A typical hot penetration detail is shown in IP2 and IP3 UFSAR Fig 5.1-30 and 5.1-12 respectively.

   There is one subsystem with two blowers for the main steam and feedwater penetrations, and one subsystem with two blowers for the hot penetrations in the radiological controlled area. Only one blower is needed in each subsystem. In the event that the operating blower stops, an alarm is initiated signaling to put the other one in service and initiate corrective actions.

   Specific system pressure values have been established, which may indicate a possible obstruction, such as a clogged filter or debris in the system. The operators make daily rounds and would initiate corrective actions if unacceptable pressure values are observed. Corrective actions may include replacement of filters, belts or silencers and blowing out of the heat exchangers, if necessary.

   System reliability was assessed by a review of IPEC operating experience over the past nine years of operation of the HPC system. The review identified no instances of loss of cooling which resulted in excess temperatures on concrete. This review identified that four IP2 and nine IP3 condition reports had been initiated. There were none that identified the cause as hot temperature on concrete. Ten were initiated due to vibrations and belt noise and three were due to increased motor temperature.

   Temperatures taken in 1994 around the IP2 main steam penetrations over a period of eleven months during normal operations indicate that concrete was exposed to a range of temperatures from a low of 109 °F to a high of about 200 °F with the highest temperature occurring during the summer months. Based upon design and actual operating experience, recommendations of the NUREG-1801 (GALL) for concrete temperature are satisfied.

Analyses have been performed to characterize the concrete temperature response in the very unlikely event of system failure. To evaluate this scenario, IPEC performed a transient heat transfer analysis of containment hot piping penetrations. The results of the analysis indicated that in the improbable case that all cooling air would be lost to these penetrations, the surrounding concrete temperature at the hottest penetration (main steam piping) would increase by about 80 °F in approximately 100 hours. It is highly improbable that cooling air would be lost for as much as 100 hours since the failure of any of the air blower drive motors is alarmed in the control room and operator daily walk downs would identify system deficiencies. Even if the adjoining concrete did reach temperatures of 250-300 °F, the strength of the structure would not be impaired for the following reasons:

1) No credit was taken for the tensile strength of the concrete around the penetrations.

2) These temperatures have substantially no effect on the strength of the penetration sleeve or the reinforcing bar in the area of the penetration.

b. The method used to arrive at the conclusion that the actual concrete strength is at least 15% greater than 3000 psi, (i.e., greater than 3450 psi) is review of actual concrete test results. The results of concrete samples taken and tested during construction in accordance with the requirements of ACI provide assurance that the minimum design strength of 3000 psi was achieved. Actual test results show that the containment shell and internal concrete had an average compressive strength of 4050 psi as indicated in response to Follow-up RAI 4: Open Item 3.5-1. No reduction in modulus of elasticity is expected for short term exposure of concrete to temperatures at or below 250 °F. Consideration of high temperatures effects on the modulus of elasticity was evaluated during the high temperature concrete evaluation. A review of information gathered from industry literature on effects of temperature concluded that concrete does not experience a significant reduction in elastic modulus due to exposure to temperatures less than 300 °F. Based on this data, no reduction in strength or modulus of elasticity was determined in the evaluation.

The applicant further stated that no response is required to part (c) of RAI 5, because the information requested in parts (a) and (b) was provided.

The staff determined that it does not agree with the applicant's assertion that reduction in modulus of elasticity of concrete would not occur at temperatures below 300 °F (*A Review of Concrete Properties for Prestressed Concrete Pressure Vessels,* R.K. Nanstad, ORNL/TM-5497, Oak Ridge National Laboratory, October 1976). However, the staff' has concluded that

Open Item 3.5-2 issue resolved for the following reasons. The staff reviewed the applicant's response dated May 1, 2009, and noted that the concrete around IP2 containment hot penetrations has been exposed to a maximum temperature of about 200 ^{o}F during the 30 plus years of operation. GALL Report Item II.A1-1 does not require further evaluation if the temperature in local areas does not exceed 200 ^{o}F during normal operation or any other long-term period. In addition, past ASME IWL visual examinations of the areas around hot penetrations have not indicated any concrete degradation. Based on the design and operation of the hot penetration cooling system, there is reasonable assurance that IP2 containment concrete around hot penetrations will be maintained below the GALL Report 200 ^{o}F limit. Therefore, the staff concludes that the applicant will adequately manage the effects of aging for IP containment concrete elements in accordance with 10 CFR 54.21(a)(3). On this basis, Open Item 3.5-2 is closed.

<u>Loss of Material Due to General, Pitting and Crevice Corrosion</u>. The staff reviewed LRA Section 3.5.2.2.1.4 using the review procedures of SRP-LR Section 3.5.3.2.1.4.

In LRA Section 3.5.2.2.1.4, the applicant stated that IP containment building concrete is in accordance with specification ACI 318, "Building Code Requirements for Reinforced Concrete," and meets requirements of the later ACI 201.2R-77 because both specifications use the same ASTM standards for concrete selection, application, and testing. Spills (*e.g.*, borated water spill) are cleaned up in a timely manner. The Structures Monitoring Program monitors interior concrete for cracks. The Containment Inservice Inspection Program (CII-IWE) inspects the steel liner plate and moisture barrier where the steel liner becomes embedded in the concrete floor. The applicant also stated that to prevent corrosion of the lower portion of the liner plate, the interior and exterior surfaces are protected from contact with the atmosphere by complete concrete encasement. Assuming a crack in the concrete, ground water cannot reach the liner plate because the concrete at this location is more than five feet thick and poured in multiple horizontal planes. Therefore, corrosion of the liner plate is not expected.

SRP-LR Section 3.5.3.2.1.4 states that the GALL Report identifies programs to manage loss of material due to general, pitting and crevice corrosion in accessible and inaccessible areas of the steel elements in drywell and torus or the steel liner and integral attachments for all types of PWR and BWR containments. The aging management program consists of ASME Section XI, Subsection IWE, and 10 CFR Part 50 Appendix J leak rate tests. Subsection IWE exempts from examination those portions of the containments that are inaccessible, such as embedded or inaccessible portions of steel liners and steel elements in drywell and torus, and integral attachments.

To cover the inaccessible areas, 10 CFR 50.55a(b)(2)(ix) requires that the applicant shall evaluate 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. In addition, the GALL Report recommends further evaluation of plant-specific programs to manage the aging effects for inaccessible areas if specific recommendations defined in the GALL Report cannot be satisfied.

The staff asked the applicant to perform a ten element comparison of its Containment Inservice Inspection AMP to GALL Report AMPs XI.S1 and XI.S2 (Audit Item 26). In a letter dated December 18, 2007, the applicant provided a comparison which confirmed that its IWE inspection program is in accordance with the regulatory requirements of 10 CFR 50.55a, and includes provisions to evaluate 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.

Review of plant operating experience identified documentation of an occurrence of mild corrosion of the IP2 liner plate at the juncture with the concrete floor slab. This area is normally inaccessible, because it is covered by thermal insulation. The applicant removed thermal insulation to conduct an investigation of the degradation; no significant degradation was uncovered. The staff's evaluation of the Containment Inservice Inspection Program is documented in SER Section 3.0.3.3.2.

The staff finds 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).

Loss of Prestress Due to Relaxation, Shrinkage, Creep, and Elevated Temperature. The staff reviewed LRA Section 3.5.2.2.1.5 using the review procedures of SRP-LR Section 3.5.3.2.1.4.

In LRA Section 3.5.2.2.1.5, the applicant stated that loss of prestress forces due to relaxation, shrinkage, creep, and elevated temperature is not applicable because there are no prestressed tendons for the containment building structures. The IP containment structures are constructed of reinforced concrete.

Because IP does not have prestressed containments, the staff finds that this aging effect does not apply.

Cumulative Fatigue Damage. The staff reviewed LRA Section 3.5.2.2.1.6 using the review procedures of SRP-LR Section 3.5.3.2.1.6.

In LRA Section 3.5.2.2.1.6, the applicant stated that TLAAs are evaluated in accordance with 10 CFR 54.21(c) as documented in (LRA) Section 4. Fatigue TLAAs for containment steel liner and associated penetrations are evaluated as documented in (LRA) Section 4.6. The only associated TLAA involves the liner plate at the penetration for feedwater line #22 on IP2. A fatigue analysis does not exist for the other penetration components. The applicant also stated that the GALL Report BWR components, i.e., suppression pool shell and unbraced downcomers, are not applicable to the IP containments.

SRP-LR Section 3.5.3.2.1.6 states fatigue analyses included in CLB for the containment liner plate and penetrations are TLAAs as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c).

The staff's review of the applicant's containment liner plate TLAA is documented in SER Section 4.6.

Cracking Due to Stress Corrosion Cracking. The staff reviewed LRA Section 3.5.2.2.1.7 using the review procedures of SRP-LR Section 3.5.3.2.1.7.

In LRA Section 3.5.2.2.1.7, the applicant stated that the GALL Report recommends further evaluation of inspection methods to detect cracking due to SCC since visual VT-3 examinations may be unable to detect this aging effect. Potentially susceptible components at IP are penetration sleeves and bellows. The applicant also stated that stress corrosion cracking (SCC) is an aging mechanism that requires the simultaneous action of an aggressive chemical environment, sustained tensile stress, and a susceptible material. Elimination of any one of these elements will eliminate susceptibility to SCC. Stainless steel elements of containment, including dissimilar welds, are not susceptible to SCC because these elements are not subject to an aggressive chemical environment. The applicant further stated that a review of plant operating experience did not identify cracking of these components.

SRP-LR Section 3.5.3.2.1.7 states that the GALL Report recommends further evaluation of programs to manage cracking due to SCC for stainless steel penetration sleeves, dissimilar metal welds and penetration bellows in all types of PWR and BWR containments and BWR vent headers, vent line bellows, and downcomers. Transgranular stress corrosion cracking (TGSCC) is a concern for dissimilar metal welds. In the case of bellows assemblies, SCC may cause aging effects particularly if the material is not shielded from a corrosive environment. Containment ISI IWE and leak rate testing may not be sufficient to detect cracks, especially for dissimilar metal welds. Additional appropriate examinations to detect SCC in bellows assemblies and dissimilar metal welds are recommended to address this issue.

The staff concurs with the applicant's assessment that all three (3) elements – stress level, susceptible material, and corrosive environment – are needed for initiation of SCC. The staff's review of IP2 and IP3 operating experience did not identify any occurrences of cracking due to SCC for these components. On this basis, the staff finds the applicant's further evaluation to be acceptable. No augmented inspection is necessary. In addition, the staff finds that because IP2 and IP3 are PWRs, they do not have BWR vent headers, vent line bellows, and downcomers.

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

Cracking Due to Cyclic Loading. The staff reviewed LRA Section 3.5.2.2.1.8 using the review procedures of SRP-LR Section 3.5.3.2.1.8.

In LRA Section 3.5.2.2.1.8, the applicant stated that this subsection lists containment components that require aging management for cracking due to cyclic loading because their original design bases did not include fatigue analyses. Specifically, containment mechanical penetrations, penetration sleeves, and dissimilar metal welds require aging management for cracking due to cyclic loading. The applicant stated that these components are designed to stress levels without requiring fatigue analyses; fine cracks are unlikely to occur. The applicant further stated that the existing requirements for leak rate testing per the Containment Leak Rate Program, and surface inspection per the Containment In-Service Inspection (CII-IWE) Program are adequate to detect cracking due to cyclic loading.

SRP-LR Section 3.5.3.2.1.8 states that the GALL Report recommends further evaluation of programs to manage cracking due to cyclic loading of steel and stainless steel penetration bellows and dissimilar metal welds in all types of PWR and BWR containments and BWR suppression pool shell and downcomers. Containment ISI IWE and leak rate testing may not be sufficient to detect fine cracks, especially for penetration bellows. VT-3 visual examination may not detect fine cracks.

In response to a staff question posed during the onsite audit and review, the applicant indicated that there has been no history of cracking in penetration bellows and dissimilar metal welds at IP. Since the number of thermal cycles is relatively low for containment penetrations and design basis calculations implicitly consider cyclic stress in the selection of the allowable stress limit, the staff finds that the applicant's assessment that IWE inspections and containment leak rate testing will be adequate to detect cracking due to cyclic loading during the extended period of operation.

The staff finds 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).

Loss of Material (Scaling, Cracking, and Spalling) Due to Freeze-Thaw. The staff reviewed LRA Section 3.5.2.2.1.9 using the review procedures of SRP-LR Section 3.5.3.2.1.9.

In LRA Section 3.5.2.2.1.9, the applicant stated that IP inaccessible and accessible concrete areas are designed in accordance with ACI 318, "Building Code Requirements for Reinforced Concrete," which results in low permeability and resistance to aggressive chemical solutions by requiring the following.

- high cement content
- low water-to-cement ratio
- proper curing
- adequate air entrainment

The applicant stated that IP concrete also meets requirements of later ACI guide ACI 201.2R-77, "Guide to Durable Concrete," since both documents use the same American Society for Testing and Material (ASTM) standards for selection, application and testing of concrete. Therefore, according to the applicant, loss of material (scaling, cracking and spalling) due to freeze-thaw is not applicable for concrete in inaccessible areas. The absence of concrete aging effects is confirmed under the Containment Inservice Inspection (CII–IWL) and Structures Monitoring Program.

SRP-LR Section 3.5.3.2.1.9 states:

> The GALL Report recommends further evaluation of programs to manage loss of material (scaling, cracking, and spalling) due to freeze-thaw for concrete elements of PWR and BWR containments. Containment ISI Subsection IWL may not be sufficient for plants located in moderate to severe weathering conditions. Evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index >100 day-inch/yr) (NUREG-1557, Ref. 7). Documented evidence confirms that where the existing concrete had air content of 3 percent to 6 percent, subsequent inspections did not exhibit degradation related to freeze-thaw. Such inspections should be considered a part of the evaluation. The weathering index for the continental US is shown in ASTM C33-90, Fig. 1. The reviewer reviews and confirms that the applicant has satisfied the recommendations for inaccessible concrete as identified in the GALL Report. Otherwise, the reviewer reviews the applicant's proposed aging management program to verify that, where appropriate, an effective inspection program has

been developed and implemented to ensure that these aging effects in inaccessible areas for plants located in moderate to severe weathering conditions are adequately managed.

The staff notes that Indian Point is located in a severe weathering region according to ASTM C33-90, Fig. 1. The applicant stated that concrete air content was at least the required minimum of between 4 and 6 percent and water-to-cement ratios were in accordance with the ACI 318-63 for IP construction, which allows a maximum water-cement ratio of up to 0.576 for concrete with the compressive strength specified for IP concrete structures. As discussed above, the applicant later revised its discussion of the water-cement ratio and air entrainment, and provided a supplemental discussion based on tests showing that the concrete exceeds the plant's 3000 psi minimum design strength. Inspections have indicated spalling on the containment cylindrical wall, which the applicant attributed to a Cadweld concrete coverage issue and not to the freeze-thaw aging mechanism. Further discussion with regard to the spalling and concrete mix properties was the subject of Open Item 3.0.3.3.2-1 and Open Item 3.5-1, respectively. Information regarding the closure of these open items is provided in SER Sections 3.0.3.3.2 and 3.5.2.2.

As discussed in the resolution of Open Item 3.0.3.3.2-1, the identified cylindrical wall concrete spalls are at locations where the reinforcing bars were spliced using Cadweld sleeves and there was insufficient concrete coverage. IWL inspections in 2005 and 2009 using enhanced visual aids have shown little, if any, additional degradation since the original detection in 2000. In the resolution of Open Item 3.5-1, the applicant provided information on the strength of in-place concrete which demonstrated that the concrete was above the 3000 psi design minimum strength required for the plant at the time of construction.

During its review, the staff noted that none of the containment spalling was attributed by the applicant to freeze-thaw, and the staff's review did not identify any spalling that was attributed to freeze-thaw. The lack of identified freeze-thaw degradation in accessible regions provides assurance that freeze-thaw degradation has not occurred in inaccessible areas. Additionally, since freeze-thaw degradation has not occurred in the first 30 years of plant operation, it is unlikely to occur in the future. However, if conditions exist in accessible areas that could indicate the presence of or result in degradation in inaccessible areas, i.e., if freeze-thaw degradation is or was identified in accessible areas, the applicant would be required to evaluate the inaccessible areas in accordance with 10 CFR 50.55a(b)(2)(viii)(E). Further, the staff notes that the GALL Report, Volume II, specifically identifies ASME Section XI, Subsection IWL, as an acceptable AMP for managing this aging effect for accessible concrete containment structures. Therefore, since the applicant is committed to IWL inspections for the extended period of operation, and containment concrete degradation has not been attributed to freeze-thaw, the staff concludes that the applicant's approach with respect to accessible areas is consistent with the GALL Report.

With regard to inaccessible areas, the applicant has identified its Structures Monitoring Program to manage the aging effects on concrete. In addition, the applicant has made the following license renewal commitment, as enhancements to the Structures Monitoring Program (Reference: Commitment 25 in the List of Regulatory Commitments, Revision 5, in Attachment 4 to Entergy's letter dated August 14, 2008):

(1) Inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete

degradation is occurring

(2) Inspect inaccessible concrete areas that are exposed by excavation for any reason.

Based on the programs and commitments identified above, the staff finds that the applicant has identified adequate programs to manage the effects of aging for both accessible and inaccessible concrete; further, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Cracking Due to Expansion and Reaction with Aggregate, and Increase in Porosity and Permeability Due to Leaching of Calcium Hydroxide</u>. The staff reviewed LRA Section 3.5.2.2.1.10 using the review procedures of SRP-LR Section 3.5.3.2.1.10.

In LRA Section 3.5.2.2.1.10, the applicant stated that in accordance with the GALL Report, aging management is not required because IP containment concrete (walls, dome, basemat and ring girder) is designed in accordance with specification ACI 318, Building Code Requirements for Reinforced Concrete, and concrete specification requires that the potential reactivity of aggregates be tested in accordance with ASTM C 289 and ASTM C 227. Also ASTM C 295 shall be used to identify elements in the aggregate which may be unfavorably reactive with alkalis in cement. The applicant states that concrete structures are not exposed to flowing water and the concrete used was constructed in accordance with the recommendations in ACI 201.2R-77 for durability. Therefore, according to the applicant, reaction with aggregates and increase in porosity and permeability due to leaching of calcium hydroxide is not an applicable aging mechanism for IP concrete structures. The applicant further stated that the absence of concrete aging effects is confirmed under the Containment Inservice Inspection (CII– IWL) and Structures Monitoring Programs.

SRP-LR Section 3.5.3.2.1.10 states that the GALL Report recommends further evaluation of programs to manage cracking due to expansion and reaction with aggregate, and increase in porosity and permeability due to leaching of calcium hydroxide in concrete elements of PWR and BWR concrete and steel containments. The GALL Report recommends containment ISI Subsection IWL to manage these aging effects. An aging management program is not necessary, even if reinforced concrete is exposed to flowing water, if there is documented evidence that confirms the in-place concrete was constructed in accordance with the recommendations in ACI 201.2R-77.

The staff notes that the GALL Report, Volume II, specifically identifies ASME Section XI, Subsection IWL, as an acceptable AMP for managing these aging effects for concrete containment structures. Although the applicant considers this aging mechanism is not an applicable mechanism for IP concrete structures, the applicant has an AMP which monitors for this aging effect/component combination. Since the applicant is committed to managing the aging effects through IWL inspections for the extended period of operation, the applicant's approach is consistent with the GALL Report.

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

3.5.2.2.2 Safety-Related and Other Structures and Component Supports

The staff reviewed LRA Section 3.5.2.2.2 against the criteria in SRP-LR Section 3.5.3.2.2.

Aging of Structures Not Covered by Structures Monitoring Program. The staff reviewed LRA Section 3.5.2.2.2.1 using the review procedures of SRP-LR Section 3.5.3.2.2.1.

In LRA Section 3.5.2.2.2.1, the applicant stated that IP concrete structures subject to aging management review, except for containment concrete covered by Containment Inservice Inspection Program (CII– IWL), are included in the Structures Monitoring Program and supplemented by other aging management programs as appropriate. The applicant states this is true for concrete items even if the aging management review did not identify aging effects requiring management. Aging effects discussed below for structural steel items are also addressed by the Structures Monitoring Program. The applicant's additional discussion of specific aging effects follows:

(1) Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling) Due to Corrosion of Embedded Steel for Groups 1-5, 7, 9 Structures

The aging mechanisms associated with cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel are applicable only to below-grade concrete/grout structures. The below-grade environment for IP is not aggressive and concrete is designed in accordance with specification ACI 318, "Building Code Requirements for Reinforced Concrete," which results in low permeability and resistance to aggressive chemical solutions by providing a high cement, low water/cement ratio, proper curing and adequate air content (between 4% and 6%). Water-cement ratios were in accordance with requirements of the version of ACI 318 used in IP construction, which allows a ratio of up to 0.576 for concrete with the compressive strength specified for IP concrete. Although specified water-cement ratios fall outside the established range of 0.35 to 0.45 provided in the guidance of the GALL Report, IP concrete meets the specifications of ACI to ensure acceptable quality concrete is obtained.

Therefore, cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel are not aging effects requiring management for IP Groups 1-5, 7, 9 structures.

(2) Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling) Due to Aggressive Chemical Attack for Groups 1-5, 7, 9 Structures

Aggressive chemical attack becomes significant to concrete exposed to an aggressive environment. Resistance to mild acid attack is enhanced by using a dense concrete with low permeability and a low water-to-cement ratio. These groups of structures at IP use a dense low-permeable concrete with a water-to-cement ratio that met the ACI 318 requirements, which provides an acceptable degree of protection against aggressive chemical attack. Water chemical analysis results confirm that the site groundwater is non-aggressive. IP concrete is constructed in accordance with the recommendations in ACI 201.2R-77 for durability.

IP below-grade environment is not aggressive. Therefore, increase in porosity and permeability cracking, loss of material (spalling, scaling) due to aggressive chemical attack are not aging effects requiring management for IP Groups 1-5, 7, 9 concrete structures.

(3) Loss of Material Due to Corrosion for Groups 1-5, 7, 8 Structures

IP Structures Monitoring Program and Containment Inservice Inspection (CII– IWE) for containment steel liner will be used to manage this aging effect for IP Groups 1-5, 7, 8 structures.

(4) Loss of Material (Spalling, Scaling) and Cracking Due to Freeze-Thaw for Groups 1-3, 5, 7-9 Structures

Aggregates were in accordance with specifications and materials conforming to ACI and ASTM standards. IP structures are constructed of a dense, durable mixture of sound coarse aggregate, fine aggregate, cement, water, and admixture. Water-cement ratios are within the limits provided in ACI 318 and air entrainment percentages are within the range prescribed in the GALL Report.

Therefore, loss of material (spalling, scaling) and cracking due to freeze thaw are not aging effects requiring management for IP Groups 1-3, 5, 7-9 structures.

(5) Cracking Due to Expansion and Reaction with Aggregates for Groups 1-5, 7-9 Structures

Aggregates were selected locally and were in accordance with specifications and materials conforming to ACI and ASTM standards at the time of construction, which are in accordance with the recommendations in ACI 201.2R-77 for concrete durability. IP structures are constructed of a dense, durable mixture of sound coarse aggregate, fine aggregate, cement, water, and admixture. Water-cement ratios are within the limits provided in ACI 318, and air entrainment percentages were within the range prescribed in the GALL Report. Therefore, cracking due to expansion and reaction with aggregates for Groups 1-5, 7-9 structures is not an aging effect requiring management.

(6) Cracks and Distortion Due to Increased Stress Levels from Settlement for Groups 1-3, 5-9 Structures

For Groups 1-3, 5-9 structures at IP, settlement is not credible since structures are founded on bedrock. Therefore, cracks and distortion due to increased stress levels from settlement for Groups 1-3, 5-9 structures is not an aging effect requiring management for IP concrete.

(7) Reduction in Foundation Strength, Cracking, Differential Settlement Due to Erosion of Porous Concrete Subfoundation for Groups 1-3, 5-9 Structures

IP concrete was provided in accordance with ACI 318 requirements resulting in dense, well-cured, high-strength concrete with low permeability, and a porous subfoundation is not provided. Structures are supported on bedrock, and erosion of the subfoundation is not credible since the subfoundation bears directly against the bedrock and the possibility of loss of soil resulting in voids below the subgrade is not credible. Operating history has not identified settlement and therefore reduction in foundation strength, cracking, differential settlement due to erosion of porous concrete subfoundation are not aging effects requiring management for IP Groups 1-3, 5-9 structures.

(8) Lock Up Due to Wear for Lubrite® Radial Beam Seats in BWR Drywell and Other Sliding Support Surfaces

IP is a reinforced concrete containment and does not contain radial beam seats; therefore, lockup due to wear for this component is not applicable. IP does use Lubrite® plate in support applications inside containment; however, owing to the wear-resistant material used, the low frequency of movement, and the slow movement between sliding surfaces, lock-up due to wear is not an aging effect requiring management at IP. Nevertheless, Lubrite® plates are included within the Inservice Inspection (ISI-IWF) Program to confirm the absence of aging effects requiring management for these components.

SRP-LR Section 3.5.3.2.2.1 states that the GALL Report recommends further evaluation of certain structure-aging effect combinations not covered by structures monitoring programs, including (1) cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel for Groups 1-5, 7, and 9 structures, (2) increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack for Groups 1-5, 7, and 9 structures, (3) loss of material due to corrosion for Groups 1-5, 7, and 8 structures, (4) loss of material (spalling, scaling) and cracking due to freeze-thaw for Groups 1-3, 5, and 7-9 structures, (5) cracking due to expansion and reaction with aggregates for Groups 1-5 and 7-9 structures, (6) cracks and distortion due to increased stress levels from settlement for Groups 1-3 and 5-9 structures, and (7) reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundation for Groups 1-3 and 5-9 structures. The GALL Report recommends further evaluation only for structure-aging effect combinations not within structures monitoring programs. In addition, the GALL Report recommends further evaluation of structure/aging effect combination of lock-up due to wear of Group 4 Lubrite® components, if they are not covered by either the ASME Section XI, Subsection IWF or the structures monitoring program. The applicant's structures monitoring program confirms that the CLB is maintained through periodic testing and inspection of critical plant structures, systems, and components.

The staff's evaluation of the above structure-aging effect combinations is provided below.

(1) Cracking, Loss of Bond, and loss of Material (Spalling, Scaling) due to Corrosion of embedded steel for Group 1-5, 7,9 structures

Through review of the LRA and bases documents, the staff found that cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel for Groups 1-5, 7, and 9 will be monitored within the Structures Monitoring Program by the applicant. Although the applicant considers that this aging effect does not require management, the applicant has an AMP which monitors for this aging effect/structure combination. On the basis that the applicant has acceptable programs in place to manage the aging effects, the staff determined that this combination will be adequately managed and no further evaluation is required.

(2) Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling) Due

to Aggressive Chemical Attack for Groups 1-5, 7, and 9 Structures

Through review of the LRA and bases documents, the staff found that increase in porosity and permeability, cracking, and loss of material (spalling; scaling) due to aggressive chemical attack for Groups 1-5, 7, and 9 structures will be monitored within the Structures Monitoring Program by the applicant. Although the applicant considers that this aging effect does not require management, the applicant has an AMP which monitors for this aging effect/structure combination. On the basis that the applicant has acceptable programs in place to manage the aging effects, the staff determined that this combination will be adequately managed and no further evaluation is required.

(3) Loss of Material Due to Corrosion for Groups 1-5, 7, and 8 Structures

Through review of the LRA and the basis document the staff found that the loss of material due to corrosion for Groups 1-5, 7, and 8 structures is an aging effect which will be managed by the applicant's Structures Monitoring Program. On this basis, the staff finds the monitoring of the above characteristic acceptable.

(4) Loss of Material (Spalling, Scaling) and Cracking Due to Freeze-Thaw for Groups 1-3, 5, and 7-9 Structures

Through review of the LRA and the basis document the staff found that the loss of material (spalling, scaling) and cracking due to freeze-thaw for Groups 1-3, 5, and 7-9 structures will be monitored within the Structures Monitoring Program by the applicant. Although the applicant considers that this aging effect does not require management, the applicant has an AMP which monitors for this aging effect/structure combination. On the basis that the applicant has acceptable programs in place to manage the aging effect, the staff determined that this combination will be adequately managed and no further evaluation is required.

(5) Cracking Due to Expansion and Reaction with Aggregates for Groups 1-5 and 7-9

Through review of the LRA and the basis document the staff found that the cracking due to expansion and reaction with aggregates for Groups 1-5 and 7-9 structures will be monitored within the Structures Monitoring Program by the applicant. Although the applicant considers that this aging effect does not require management, the applicant has an AMP which monitors for this aging effect/structure combination. On the basis that the applicant has acceptable programs in place to manage the aging effects, the staff determined that this combination will be adequately managed and no further evaluation is required.

(6) Cracks and Distortion Due to Increased Stress Levels from Settlement for Groups 1-3 and 5-9 Structures

Through review of LRA and the basis document the staff found that cracks and distortion due to increased stress levels from settlement for Groups 1-3 and 5-9 structures is not a plausible aging effect at IP because of the nonexistence of this aging mechanism. The IP Class 1 structures are founded on sound bedrock or supported by steel pilings which prevent significant settlement. The staff finds the applicant's assessment that these aging effects are not applicable to IP Class I structures is acceptable. On the basis that

IP does not have any components from this group, the staff found that this aging effect is not applicable to IP.

(7) Reduction in Foundation Strength, Cracking, and Differential Settlement Due to Erosion of Porous Concrete Subfoundation for Groups 1-3 and 5-9 Structures

Through review of the LRA and bases documents, the staff found that reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundation for Groups 1-3 and 5-9 structures are not plausible aging effects because of the nonexistence of these aging mechanisms. The applicant stated that the aging effects of reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundation for Groups 1-3 and 5-9 structures are not applicable to IP since there are no porous concrete subfoundations of concern below these structures. Due to the absence of porous concrete subfoundations, the staff finds these aging effects are not applicable to IP.

(8) Lockup Due to Wear for Lubrite® Radial Beam Seats in BWR Drywell and Other Sliding Support Surfaces.

Through review of the LRA, the staff found that the applicant has credited its Inservice Inspection (ISI–IWF) program to manage aging of Lubrite® and other sliding support surfaces. The staff finds the applicable AMP (IWF) acceptable for inspection of Lubrite® and other sliding support surfaces. The staff's evaluation of the ISI-IWF Program is contained in SER Section 3.0.3.3.4.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.5.2.2.2.1 criteria. For those line items that apply to LRA Section 3.5.2.2.2.1, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Aging Management of Inaccessible Areas</u>. The staff reviewed LRA Section 3.5.2.2.2.2 using the review procedures of SRP-LR Section 3.5.3.2.2.2.

In LRA Section 3.5.2.2.2.2, the applicant stated that IP concrete for Group 1-3, 5 and 7-9 inaccessible concrete areas was provided in accordance with specification ACI 318, Building Code Requirements for Reinforced Concrete, which requires the following, resulting in low permeability and resistance to aggressive chemical solution:

- high cement content
- low water permeability
- proper curing
- adequate air entrainment

The applicant states that IP concrete also meets requirements of later ACI guide ACI 201.2R-77, "Guide to Durable Concrete," since both documents use the same ASTM standards for selection, application and testing of concrete. Inspections of accessible concrete have not revealed degradation related to corrosion of embedded steel. IP below-grade environment is not aggressive as defined in the GALL Report. Therefore, according to the applicant, loss of material due to corrosion of embedded steel is not an aging effect requiring management for IP concrete.

SRP-LR Section 3.5.3.2.2.2 states:

(1) The GALL Report recommends further evaluation of programs to manage loss of material (spalling, scaling) and cracking due to freeze-thaw in below-grade inaccessible concrete areas of Groups 1-3, 5, and 7-9 structures. Structures monitoring program may not be sufficient for plants located in moderate to severe weathering conditions. Further evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index >100 day-inch/yr) (NUREG-1557). Documented evidence confirms that where the existing concrete had air content of 3% to 6% and water-to-cement ratio of 0.35-0.45, subsequent inspection did not exhibit degradation related to freeze-thaw. Such inspections should be considered a part of the evaluation. The weathering index for the continental U.S. is shown in ASTM C33-90, Fig. 1.

(2) The GALL Report recommends further evaluation of programs to manage cracking due to expansion and reaction with aggregate in below-grade inaccessible concrete areas of Groups 1-5 and 7-9 structures in below-grade inaccessible concrete areas of Groups 1-3, 5, and 7-9 structures. An aging management program is not necessary, if there is documented evidence that confirms the in-place concrete was constructed in accordance with the recommendations in ACI 201.2R-77.

(3) The GALL Report recommends further evaluation of programs to manage cracks and distortion due to increased stress levels from settlement, and reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations could occur in below-grade inaccessible concrete areas of Groups 1-3, 5, and 7-9 structures. The initial licensing basis for some plants included a program to monitor settlement. If no settlement was evident during the first decade or so, the staff may have given the applicant approval to discontinue the program. However, if a de-watering system is relied upon for control of settlement and erosion, then the applicant is to ensure proper functioning of the de-watering system through the period of extended operation.

(4) The GALL Report recommends further evaluation of aging management for inaccessible concrete areas, such as foundation and exterior walls below grade exposed to an aggressive environment. Possible aging effects are increases in porosity and permeability, cracking and loss of material (spalling, scaling) due to aggressive chemical attack, and cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel for Groups 1-3, 5, 7-9 structures. Periodic monitoring of below-grade water chemistry (including consideration of potential seasonal variations) is an acceptable approach to demonstrate that the below-grade environment is aggressive or non-aggressive. The GALL Report recommends that examination of representative samples of below-grade concrete, when excavated for any reason, be performed.

(5) The GALL Report recommends further evaluation of programs to manage increase in porosity and permeability due to leaching of calcium hydroxide in below-grade inaccessible concrete areas of Groups 1-3, 5, and 7-9 structures. An aging management program is not necessary, if there is documented evidence that confirms the in-place concrete was constructed in accordance with the recommendations in ACI 201.2R-77.

The staff's evaluation of the above structure-aging effect combinations is provided below.

The staff noted that the applicant's further evaluation discussion in LRA 3.5.2.2.2.2 does not identify any commitments to monitor inaccessible areas. In response to the staff's review, the applicant has made the following license renewal commitments related to inaccessible areas, as enhancements to the SMP (Reference: Commitment 25 in the List of Regulatory Commitments, Revision 5, in Attachment 4 to Entergy's letter dated August 14, 2008):

(1) Inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring in such inaccessible areas, as part of its Structures Monitoring AMP

(2) Conduct a groundwater monitoring program that is sufficient in scope to assess the aggressiveness of the site groundwater to concrete on a periodic basis, as part of its Structures Monitoring AMP

(3) Inspect inaccessible concrete areas that are exposed by excavation for any reason, as part of its Structures Monitoring AMP

Based on the programs and commitments identified above, the staff determined that the applicant has an adequate program for monitoring all five structure-aging effect combinations mentioned above for inaccessible areas of containment concrete. Therefore, the staff finds that upon satisfactory resolution of Open Item 3.5-1, the applicant's approach 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).

Reduction of Strength and Modulus of Concrete Structures Due to Elevated Temperature. The staff reviewed LRA Section 3.5.2.2.2.3 using the review procedures of SRP-LR Section 3.5.3.2.2.3.

In LRA Section 3.5.2.2.2.3, the applicant stated that this aging effect is not applicable because during normal operation, bulk average temperature of Groups 1-5 concrete elements is below 150ºF and local temperatures remain below 200ºF. Group 1-5 concrete elements remain at temperatures below the thresholds for aging degradation due to elevated temperature.

SRP-LR Section 3.5.3.2.2.3 states that the GALL Report recommends a plant-specific evaluation be performed if any portion of the concrete Groups 1-5 structures exceeds specified temperature limits, i.e., general temperature greater than 66°C (150°F) and local area temperature greater than 93°C (200°F).

Based on the above, the staff concludes that reduction of strength and modulus of concrete structures due to elevated temperature is not applicable to Groups 1 through 5 structures at IP since the GALL Report temperature limits are not exceeded.

The staff finds that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as

required by 10 CFR 54.21(a)(3).

Aging Management of Inaccessible Areas for Group 6 Structures. The staff reviewed LRA Section 3.5.2.2.2.4 using the review procedures of SRP-LR Section 3.5.3.2.2.4.

In LRA Section 3.5.2.2.2.4, the applicant stated that, for inaccessible areas of certain Group 6 structures, aging effects are covered by inspections in accordance with the Structures Monitoring Program. The Structures Monitoring Program will include guidance to perform periodic engineering evaluations of groundwater samples to assess aggressiveness of groundwater to concrete. The applicant provided the following additional information:

1. Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)/Aggressive Chemical Attack; and Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)/Corrosion of Embedded Steel in Below-Grade Inaccessible Concrete Areas of Group 6 Structures

   Below-grade exterior reinforced concrete structures are subject to non aggressive environment (pH > 5.5, chlorides < 500 ppm, and sulfates < 1,500 ppm). Therefore, increase in porosity and permeability, cracking, loss of material (spalling, scaling)/ aggressive chemical attack; and cracking, loss of bond, and loss of material (spalling, scaling)/ corrosion of embedded steel are not aging effects requiring management for below-grade inaccessible concrete areas of IP Group 6 structures.

2. Loss of Material (Spalling, Scaling) and Cracking Due to Freeze-thaw in Below-Grade Inaccessible Concrete Areas of Group 6 Structures

   Aggregates were selected locally and were in accordance with specifications and materials conforming to ACI and ASTM standards at the time of construction. IP structures are constructed of a dense, durable mixture of sound coarse aggregate, fine aggregate, cement, water, and admixture. Water-cement ratios are within the limits provided in ACI 318, and air entrainment percentages were within the range prescribed in the GALL Report. Therefore, loss of material (spalling, scaling) and cracking due to freeze thaw are not aging effects requiring management for IP Groups 6 structures.

3. Cracking Due to Expansion and Reaction with Aggregates, Increase in Porosity and Permeability, and Loss of Strength Due to Leaching of Calcium Hydroxide in Below-Grade Inaccessible Concrete Areas of Group 6 Structures

   Aggregates were selected locally and were in accordance with specifications and materials conforming to ACI and ASTM standards at the time of construction, which are in accordance with the recommendations in ACI 201.2R-77 for concrete durability. IP structures are constructed of a dense, durable mixture of sound coarse aggregate, fine aggregate, cement, water, and admixture. Water-cement ratios are within the limits provided in ACI 318-63, and air entrainment percentages were within the range prescribed in the GALL Report. IP below-grade environment is not aggressive (pH > 5.5, chlorides < 500 ppm, and sulfates < 1,500 ppm). Therefore, cracking due to expansion and reaction with aggregates, increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide in below-grade inaccessible concrete areas of Group 6 Structures is not an aging effect requiring management for IP concrete.

SRP-LR Section 3.5.3.2.2.4 states that the GALL Report recommends further evaluation for inaccessible areas of certain Group 6 structure/aging effect combinations as identified below, whether or not they are covered by inspections in accordance with the GALL Report, Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," or the Federal Energy Regulatory Commission/US Army Corp of Engineers dam inspections and maintenance.

1. Increases in porosity and permeability, cracking and loss of material (spalling, scaling) due to aggressive chemical attack and cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel could occur in below-grade inaccessible concrete areas of Group 6 structures. Periodic monitoring of below-grade water chemistry (including consideration of potential seasonal variations) is an acceptable approach to demonstrate that the below-grade environment is aggressive or non-aggressive. The GALL Report recommends that examination of representative samples of below-grade concrete, when excavated for any reason, be performed, if the below-grade environment is aggressive.

2. Loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas of Group 6 structures. Further evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index >100 day-inch/yr) (NUREG-1557, Ref. 7). Documented evidence confirms that where the existing concrete had air content of 3% to 6% and water-to-cement ratio of 0.35-0.45, subsequent inspection did not exhibit degradation related to freeze-thaw. Such inspections should be considered a part of the evaluation. The weathering index for the continental US is shown in ASTM C33-90, Fig. 1.

3. Cracking due to expansion and reaction with aggregate could occur in below-grade inaccessible concrete areas of Group 6 structures and increase in porosity and permeability due to leaching of calcium hydroxide could occur in below-grade inaccessible concrete areas of Group 6 structures. An aging management program is not necessary, even if reinforced concrete is exposed to flowing water, if there is documented evidence that confirms the in-place concrete was constructed in accordance with the recommendations in ACI 201.2R-77.

The staff's evaluation of the above structure-aging effect combinations is given below.

The staff noted that the applicant's initial commitment to managing aging of inaccessible areas of Group 6 structures (water control structures) was insufficient because the Structures Monitoring AMP did not include specific provisions identified in GALL AMP XI.S7 "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants". The staff asked the applicant to describe how all the provisions of GALL AMP XI.S7 had been incorporated into its Structures Monitoring AMP (Audit Item 88). As a result of the staff's inquiries, the applicant made the following additional license renewal commitments to enhance the Structures Monitoring AMP (Reference: Commitment 25 in the List of Regulatory Commitments, Revision 5, in Attachment 4 to Entergy's letter dated August 14, 2008):

(1) Perform inspection of normally submerged concrete portions of the intake structures at least once every five years.

The applicant had also made commitments to enhance the Structures Monitoring AMP, for managing aging of inaccessible areas for all structures groups.

(2) Conduct a groundwater monitoring program that is sufficient in scope to assess the aggressiveness of the site groundwater to concrete on a periodic basis.

(3) Conduct inspection of inaccessible concrete areas that are exposed by excavation for any reason.

(4) Inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring in such inaccessible areas.

The staff's review of operating experience identified the existence of concrete degradation of water control structures. Spalling of concrete and rusting of rebar has occurred at a number of locations. The staff's evaluation of these conditions is in Section 3.0.3.2.15 of this SER.

Although the applicant considers that the above mentioned aging effects do not require management, its Structures Monitoring Program with the above commitments monitors for these aging effect/structure combinations. Based on the programs and commitments identified above, the staff finds that the LRA is consistent with the GALL Report for the three structure aging effect combinations, and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Cracking Due to Stress Corrosion Cracking and Loss of Material Due to Pitting and Crevice Corrosion. The staff reviewed LRA Section 3.5.2.2.2.5 using the review procedures of SRP-LR Section 3.5.3.2.2.5.

In LRA Section 3.5.2.2.2.5, the applicant addressed cracking due to SCC and loss of material due to pitting and crevice corrosion in stainless steel tank liners, by stating that this aging effect is not applicable because there are no concrete or steel tanks with stainless steel liners within the scope of license renewal.

In SRP-LR Section 3.5.3.2.2.5, it states that the GALL Report recommends further evaluation of plant-specific programs to manage cracking due to SCC and loss of material due to pitting and crevice corrosion for stainless steel tank liners exposed to standing water.

On the basis that there are no stainless steel tank liners within the scope of license renewal, the staff concludes that the SRP-LR criterion is not applicable, and further evaluation is not required.

Aging of Supports Not Covered by the Structures Monitoring Program. The staff reviewed LRA Section 3.5.2.2.2.6 using the review procedures of SRP-LR Section 3.5.3.2.2.6.

In LRA Section 3.5.2.2.2.6, the applicant stated that the GALL Report recommends further evaluation of certain component support/aging effect combinations if they are not covered by the applicant's structures monitoring program. Component supports at IP are included in the Structures Monitoring Program for Groups B2 through B5 and the Inservice Inspection (ISI-IWF) program for Group B1. The applicant provided the following additional information:

(1) Reduction in concrete anchor capacity due to degradation of the surrounding concrete for Groups B1 through B5 supports:

IP concrete anchors and surrounding concrete are included in the Structures Monitoring Program (Groups B2 through B5) and Inservice Inspection (ISI-IWF) Program (Group B1).

Item 3.5.1-40 of LRA Table 3.5.1 addresses building concrete at locations of expansion and grouted anchors for the aging effect of reduction in concrete anchor capacity due to local concrete degradation/service-induced cracking or other concrete aging mechanisms. The GALL Report recommends the Structures Monitoring Program for monitoring this concrete component for the stated aging effect. The staff finds that the applicant has appropriately credited the SMP for Groups B2 through B5 component supports and surrounding concrete consistent with the GALL Report. However, for the Group B1 (ASME Class 1, 2, 3 & MC) supports, the applicant's statement that "IP concrete anchors and surrounding concrete" implies that the applicant is crediting the ISI-IWF AMP for both the supports and surrounding concrete. The staff found that, while ISI-IWF is appropriate for the Group B1 component supports themselves, ISI-IWF is not specifically applicable for concrete surrounding the anchors for these supports, because of the code support boundary definition which extends to the surface of the building but does not include the building structure. Therefore, the applicant was requested to confirm which AMP it is using to manage the effects of aging for the concrete surrounding the B1 supports. This was identified as Open Item 3.5-3.

In its response to Open Item 3.5-3 in Attachment 1, dated January 27, 2009, the applicant stated that, as indicated in the discussion column for Item 3.5.1-40 of LRA Table 3.5.1, the applicable aging management program for concrete surrounding concrete anchors is the Structures Monitoring Program. The applicant stated that the evaluation provided in LRA Section 3.5.2.2.2.6 (1), reproduced as the first paragraph under Item (1) above of the SER, is clarified to read as follows: "Concrete surrounding IPEC concrete anchors is included in the Structures Monitoring Program (Groups B1 through B5)."

The staff finds the above response to Open Item 3.5-3 acceptable since the applicant clarified and revised its evaluation in LRA Section 3.5.2.2.2.6 (1) to confirm that the aging management program for building concrete and grout pads at locations surrounding anchors and base plates of Groups B1 through B5 supports is the Structures Monitoring Program, which makes it consistent with the GALL Report. Therefore, the issue raised in Open Item 3.5-3 is closed.

(2) Loss of material due to general and pitting corrosion, for Groups B2 through B5 supports:

Loss of material due to corrosion of steel support components is an aging effect requiring management at IP. The Structures Monitoring Program manages this aging effect. For components subject to loss of material due to boric acid corrosion, the Boric Acid Corrosion Prevention Program manages this aging effect.

One entry covers loss of material for carbon steel fire damper framing in an indoor air (uncontrolled) environment. The applicant references Table 1 Item 3.5.1-39, and credits the Fire Protection Program. One entry covers loss of material for carbon steel fire hose reels in an indoor air (uncontrolled) environment. The applicant references Table 1 Item 3.5.1-39, and credits the Fire Water System Program. The applicant references Table 1 Item 3.5.1-25, and credits the Fire Protection Program. The applicant has also credited the Structures Monitoring Program in a separate Table 2 entry. Although the GALL Report identifies the Structures Monitoring Program as the acceptable AMP, structural commodities related to plant fire protection are typically inspected under either the Fire Protection AMP or the Fire Water System Program. For the specific applications cited above, the staff considers these AMPs to be acceptable alternatives or adjuncts to the Structures Monitoring Program. The staff's evaluation of these conditions is discussed in SER Sections 3.0.3.2.7 and 3.0.3.2.8.

(3) Reduction/loss of isolation function due to degradation of vibration isolation elements for Group B4 supports:

The IP aging management review did not identify any component support structure/aging effect combination corresponding to NUREG-1801 Volume 2 Item III.B4.2-a.

SRP-LR Section 3.5.3.2.2.1 states that the GALL Report recommends further evaluation of certain component support/aging effect combinations if they are not covered by the structures monitoring program. This includes (1) reduction in concrete anchor capacity due to degradation of the surrounding concrete, for Groups B1-B5 supports; (2) loss of material due to general and pitting corrosion, for Groups B2-B5 supports; and (3) reduction/loss of isolation function due to degradation of vibration isolation elements, for Group B4 supports. Further evaluation is necessary only for structure/aging effect combinations not covered by the structures monitoring program.

The staff noted that Items (1) and (2) above are included in the scope of the applicant's Structures Monitoring Program, and Item (3) is not applicable. Since the combination is covered by the applicant's Structures Monitoring Program, as recommended by the SRP-LR, further evaluation is not necessary.

The staff finds 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).

Cumulative Fatigue Damage Due to Cyclic Loading. LRA Section 3.5.2.2.2.7 states that TLAAs are evaluated in accordance with 10 CFR 54.21(c), as documented in (LRA) Section 4. During the process of identifying TLAAs in the IP current licensing basis, no fatigue analyses were identified for ASME component support members, anchor bolts, and welds.

Based on the above, the staff concludes that this further evaluation is not applicable, because no fatigue analyses exist in the current licensing basis for the ASME component support members, anchor bolts, or welds.

3.5.2.2.3 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA program.

3.5.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.5.2-1 through 3.5.2-4, 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 3.5.2-1 through 3.5.2-4, the applicant indicated, via Notes F through J that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information about how it will manage the aging effects. Specifically, note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicate that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation. The staff's evaluation is documented in the following sections.

3.5.2.3.1 Containment Building - Summary of Aging Management Review – LRA Table 3.5.2-1

The staff reviewed LRA Table 3.5.2-1, as amended by letter date June 11, 2008, which summarizes the results of AMR evaluations for the containment building component groups.

The applicant identified 38 unique component/material/environment/aging effect/AMP groups for the containment building. Twenty-seven have AMR results consistent with the GALL Report, as identified by reference to Notes A through E. The staff confirmed that the references to Table 1 and GALL Report Volume II line items are appropriate.

The applicant referenced Note F for nickel alloy bellows penetrations exposed to uncontrolled air-indoor (internal) with no aging effects and no aging management program required. This material has high corrosion resistance as discussed in "Metals Handbook, Desk Edition, 1985" and therefore no aging effects are expected and no AMP is required. Therefore, the staff finds the applicant's AMR results acceptable.

The applicant referenced Note I and plant-specific Note 501, which states "[t]he IP environment is not conducive to the listed aging effects. However, the identified AMP will be used to confirm the absence of significant aging effects for the period of extended operation." The applicant identified its Structures Monitoring Program, ISI-IWF, CII-IWL, or Fire Protection Program to manage the aging effects. The staff's review of the above programs is documented in SER Sections 3.0.3.2.15, 3.0.3.3.4, 3.0.3.3.2, and 3.0.3.2.7, respectively. The staff finds that the credited AMP is appropriate in each case. Since the applicant has committed to appropriate AMPs for the period of extended operation, the staff finds these AMR results to be acceptable.

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

3.5.2.3.2 Water Control Structures - Summary of Aging Management Review – LRA Table 3.5.2-2

The staff reviewed LRA Table 3.5.2-2, which summarizes the results of AMR evaluations for the water control structures component groups. The staff confirmed that the references to Table 1 and GALL Report, Volume II line items are appropriate.

The applicant proposes to manage concrete material, aging effect none, by using the Structures Monitoring Program. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.15. These line items reference Note I and plant-specific Note 501, which states "[t]he IP environment is not conducive to the listed aging effects. However, the identified AMP will be used to confirm the absence of significant aging effects for the period of extended operation." Although the applicant considers that this aging effect does not exist at its plant, the applicant has an AMP which monitors for this aging effect/structure combination. On the basis that the applicant has committed to appropriate aging management programs for the period of extended operation, the staff finds these AMR results to be acceptable.

By letter dated March 24, 2008, the applicant added baffling/grating partition and support platform for IP3 constructed of Fiberglass material exposed to a fluid environment. The applicant proposes to manage the loss of material aging effect for this component using the Structures Monitoring Program. This line item references Note J, which states that neither the component nor the material and environment combination is evaluated in NUREG-1801. The applicant has credited the Structures Monitoring Program to manage the loss of material aging effect in a fluid environment for materials such as concrete, carbon steel, stainless steel, copper alloy using Note E. Based on the rationale used in SER Section 3.5.2.1 for these materials with Note E subject to a fluid environment, the staff finds the AMP the applicant has proposed for the fiberglass material component is appropriate and acceptable.

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

3.5.2.3.3 Turbine Building, Auxiliary Building, and Other Structures - Summary of Aging Management Review – LRA Table 3.5.2-3

The staff reviewed LRA Table 3.5.2-3, which summarizes the results of AMR evaluations for the turbine building, auxiliary building, and other structures component groups. The staff confirmed that the references to Table 1 and GALL Report, Volume II line items are appropriate.

The applicant proposes to manage concrete material, aging effect “none,” by using the Structures Monitoring Program. The staff’s review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.15. These line items reference Note I and plant-specific Note 501, which states “[t]he IP environment is not conducive to the listed aging effects. However, the identified AMP will be used to confirm the absence of significant aging effects for the period of extended operation.” Although the applicant considers that this aging effect does not exist at its plant, the applicant has an AMP which monitors for this aging effect/structure combination. Because the applicant has committed to the appropriate aging management program for the period of extended operation, the staff finds these AMR results to be acceptable.

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

3.5.2.3.4 Bulk Commodities - Summary of Aging Management Review – LRA Table 3.5.2-4

The staff reviewed LRA Table 3.5.2-4, which summarizes the results of AMR evaluations for the bulk commodities component groups. The staff confirmed that the references to Table 1 and GALL Report, Volume II line items are appropriate.

The applicant proposes to manage concrete material, aging effect “none,” by using the Structures Monitoring Program. The staff’s review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.15. These line items reference Note I and plant-specific Note 501, which states “The IP environment is not conducive to the listed aging effects. However, the identified AMP will be used to confirm the absence of significant aging effects for the period of extended operation.” Although the applicant considers that this aging effect does not exist at its plant, the applicant has an AMP which monitors for this aging effect/structure combination. On the basis that the applicant has committed to appropriate aging management programs for the period of extended operation, the staff finds these AMR results to be acceptable.

The applicant references Note J, indicating that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report. The specific component/material/environment/aging effect/AMP groups referencing Note J are:

(1) Fire stops/cera blanket, mineral wool/air – indoor uncontrolled/cracking, de-lamination, separation/ Fire Protection

(2) Fire wrap/cerafiber, cera blanket/air – indoor uncontrolled/loss of material/ Fire Protection

(3) Insulation/fiberglass, calcium silicate/air – indoor uncontrolled/None/None

Plant-specific Note 502 is referenced, which states:

> Loss of insulating characteristics due to insulation degradation is not an aging effect requiring management for insulation material.

Insulation products, which are made from fiberglass fiber, calcium silicate, stainless steel, and similar materials, in an air – indoor uncontrolled environment do not experience aging effects that would significantly degrade their ability to insulate as designed. A review of site operating experience identified no aging effects for insulation used at IP.

(4) Water stops/elastomers/air – indoor uncontrolled/None/None

The staff confirmed that groups (1) and (2) are within the scope of the applicant's Fire Protection Program. Since these components/materials serve the intended function of a fire barrier, the staff considers the Fire Protection AMP to be an appropriate and acceptable program for aging management of the listed aging effects. Therefore, the staff finds the applicant's AMR results acceptable. The staff's review of the Fire Protection Program is documented in SER Section 3.0.3.2.7.

For group (3), the staff concurs that deterioration of the insulation function in an indoor air environment is not expected. The staff questioned the applicant about any occurrences of moisture wetting the insulation (Audit Item 248). In its response, dated December 18, 2007, the applicant stated that there have been no occurrences, because the insulation is jacketed. Since the stated aging effect is not expected for insulation in an indoor environment and is also not indicated in the applicant's operating experience, the staff finds the applicant's AMR results acceptable.

For group (4), the staff notes that water stops are completely embedded in concrete joints between walls and floors, to eliminate water leakage through the joints. They are inaccessible for inspection. The GALL Report does not recommend inspection of water stops.

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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.3 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 System

This section of the SER documents the staff's review of the applicant's AMR results for the following electrical and instrumentation and control (I&C) system components and component groups:

- high-voltage insulators
- insulated cables and connections
- metal-enclosed bus
- switchyard bus and connections
- transmission conductors and connections
- direct burial 138-kilovolt (kV) insulated transmission cables

3.6.1 Summary of Technical Information in the Application

LRA Section 3.6 provides AMR results for the electrical and I&C system components and component groups. LRA Table 3.6.1, "Summary of Aging Management Programs for the Electrical and I&C Components Evaluated in Chapter VI of NUREG 1801," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the electrical and I&C system components and component groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.6.2 Staff Evaluation

The staff reviewed LRA Section 3.6 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging, for the electrical and I&C system components within the scope of license renewal and subject to an AMR, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff conducted an onsite audit of AMRs to verify the applicant's claim that certain AMRs are consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA is applicable and that the applicant identified the appropriate GALL Report AMRs. SER Section 3.0.3 documents the staff's evaluations of the AMPs. SER Section 3.6.2.1 documents the details of the staff's audit evaluation.

During the onsite audit, the staff also selected AMRs consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations are consistent with the SRP-LR Section 3.6.2.2 acceptance criteria. SER Section 3.6.2.2 documents the staff's audit evaluations.

The staff also conducted a technical review of the remaining AMRs not consistent with or not addressed in the GALL Report. The technical review evaluated whether all plausible aging effects have been identified and whether the aging effects listed are appropriate for the material-environment combinations specified. SER Section 3.6.2.3 documents the staff's evaluations.

For components that the applicant claimed are not applicable or require no aging management, the staff reviewed the AMR line items and the plant's operating experience to verify 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.

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

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Electrical equipment subject to 10 CFR 50.49 environmental qualification (EQ) requirements (3.6.1-1)	Degradation due to various aging mechanisms	Environmental Qualification of Electric Components	Yes	TLAA	Consistent with GALL Report (see Section 3.6.2.2.1)
Electrical cables, connections and fuse holders (insulation) not subject to 10 CFR 50.49 EQ requirements (3.6.1-2)	Reduced insulation resistance and electrical failure due to various physical, thermal, radiolytic, photolytic, and chemical mechanisms	Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements	No	Non-EQ Insulated Cables and Connections	Consistent with GALL Report (see Section 3.6.2.1)
Conductor insulation for electrical cables and connections used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements that are sensitive to reduction in conductor insulation resistance (3.6.1-3)	Reduced insulation resistance and electrical failure due to various physical, thermal, radiolytic, photolytic, and chemical mechanisms	Electrical Cables and Connections Used In Instrumentation Circuits Not Subject to 10 CFR 50.49 EQ Requirements	No	Non-EQ Instrumentation Circuit Test Review	Consistent with GALL Report (see Section 3.6.2.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Conductor insulation for inaccessible medium-voltage (2-kV to 35-kV) cables (e.g., installed in conduit or direct buried) not subject to 10 CFR 50.49 EQ requirements (3.6.1-4)	Localized damage and breakdown of insulation leading to electrical failure due to moisture intrusion, water trees	Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements	No	Non-EQ Inaccessible Medium-Voltage Cables	Consistent with GALL Report (see SER Section 3.6.2.1)
Connector contacts for electrical connectors exposed to borated water leakage (3.6.1-5)	Corrosion of connector contact surfaces due to intrusion of borated water	Boric Acid Corrosion	No	Boric Acid Corrosion Prevention	Consistent with GALL Report (see SER Section 3.6.2.1)
Fuse Holders (Not Part of a Larger Assembly): Fuse holders - metallic clamp (3.6.1-6)	Fatigue due to ohmic heating, thermal cycling, electrical transients, frequent manipulation, vibration, chemical contamination, corrosion, and oxidation	Fuse Holders	No	Not applicable	Not applicable (see SER Section 3.6.2.1.1)
Metal-enclosed bus—bus, connections (3.6.1-7)	Loosening of bolted connections due to thermal cycling and ohmic heating	Metal-Enclosed Bus	No	Metal-Enclosed Bus Inspection	Consistent with GALL Report (see SER Section 3.6.2.1)
Metal-enclosed bus—insulation, insulators (3.6.1-8)	Reduced insulation resistance and electrical failure due to various physical, thermal, radiolytic, photolytic, and chemical mechanisms	Metal-Enclosed Bus	No	Metal-Enclosed Bus Inspection	Consistent with GALL Report (see SER Section 3.6.2.1)
Metal-enclosed bus—enclosure assemblies (3.6.1-9)	Loss of material due to general corrosion	Structures Monitoring Program	No	Metal-Enclosed Bus Inspection	Consistent with GALL Report (see SER Section 3.6.2.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Metal enclosed bus - enclosure assemblies (3.6.1-10)	Hardening and loss of strength due to elastomers degradation	Structures Monitoring Program	No	Not applicable	Not consistent with GALL Report (see Section 3.6.2.3)
High voltage insulators (3.6.1-11)	Degradation of insulation quality due to presence of any salt deposits and surface contamination; loss of material caused by mechanical wear due to wind blowing on transmission conductors	A plant-specific aging management program is to be evaluated	Yes	None	Consistent with GALL Report (see SER Section 3.6.2.2.2)
Transmission conductors and connections; switchyard bus and connections (3.6.1-12)	Loss of material due to wind induced abrasion and fatigue; loss of conductor strength due to corrosion; increased resistance of connection due to oxidation or loss of preload	A plant-specific aging management program is to be evaluated	Yes	None	Consistent with GALL Report (see SER Section 3.6.2.2.3)
Cable connections - metallic parts (3.6.1-13)	Loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	No	Non-EQ Bolted Cable Connections	Consistent with GALL Report (see SER Section 3.6.2.1)
Fuse holders (Not Part of a Larger Assembly) - insulation material (3.6.1-14)	None	None	NA	Not Applicable	Consistent with GALL Report

The staff's review of the electrical and I&C system component groups followed one of the following approaches. In one approach, documented in SER Section 3.6.2.1, the staff reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. In the second approach, documented in SER Section 3.6.2.2, the staff reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. In the third approach, documented in SER Section 3.6.2.3, the staff reviewed AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. SER Section 3.0.3 documents the staff's review of AMPs credited to manage or monitor the aging effects of the electrical and I&C system components.

3.6.2.1 AMR Results Consistent with the GALL Report

In LRA Section 3.6.2.1, the applicant identified the materials, environments, AERMs, and the following programs that manage aging effects for the electrical and I&C system components:

- Boric Acid Corrosion Prevention Program
- Metal-Enclosed Bus Inspection Program
- Non-EQ Bolted Cable Connections Program
- Non-EQ Inaccessible Medium-Voltage Cable Program
- Non-EQ Instrumentation Circuits Test Review Program
- Non-EQ Insulated Cables and Connections Program

LRA Table 3.6.2-1 summarizes the results of AMRs for the electrical and I&C system components and indicates the AMRs claimed to be consistent with the GALL Report.

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

For each AMR line item, the applicant stated how the information in the tables aligns with the information in the GALL Report. Notes A through E indicate how the AMR is consistent with the GALL Report. The staff audited these AMRs.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report and validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report and verified that the identified exceptions to the GALL Report AMPs have been reviewed and accepted. The staff also determined whether the applicant's AMP is consistent with the GALL Report AMP and whether the AMR is valid for the site-specific conditions.

Note C indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the 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 line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component is applicable to the component under review and whether the AMR is valid for the site-specific conditions.

Note D indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report. The staff ascertained whether the AMR line item of the different component is 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 is consistent with the GALL Report AMP and whether the AMR is valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect but credits a different AMP. The staff audited these line items to verify their 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 is valid for the site-specific conditions.

The staff audited and reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA is applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluation follows.

The staff reviewed LRA Table 3.6.1, which summarizes the results of AMR evaluations in Chapter VI of the GALL Report for the electrical and I&C component groups.

The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging on these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.1.1 AMR Results Identified as Not Applicable

In the discussion column of LRA Table 3.6.1 for Item 3.6.1-6, the applicant stated that fatigue due to ohmic heating, thermal cycling, electrical transients, frequent manipulation, vibration, chemical contamination, corrosion, and oxidation of fuse holders (not part of a larger assembly)—metallic clamp is not applicable to IP because all fuse holders utilizing metallic clamps are either part of an active device or located in circuits that perform no function intended for license renewal. In accordance with 10 CFR 54.21(a)(1)(i), fuse holders installed in an active assembly are part of an active assembly and do not require an AMR. Therefore, the staff finds that fuse holders with metallic clamps at IP are not subject to AMR.

3.6.2.1.2 Loss of Material Due to General Corrosion

In the discussion section in Table 3.6.1, Item 3.6.1-9, of the LRA, the applicant stated that the Metal-Enclosed Bus Inspection Program will manage the effect of loss of material due to general corrosion through visual inspection. The staff noted that in the AMR results line that points to Table 3.6.1, Item 3.6.1-9, the applicant included a reference to Note E.

The staff reviewed the AMR results lines referenced to Note E and determined that the component type, material, environment, and aging effect are consistent with the corresponding lines of the GALL Report; however, where the GALL Report recommends the AMP XI.S6, "Structures Monitoring Program," the applicant has proposed the Metal-Enclosed Bus Inspection Program. As discussed in Section 3.0.3.1, the staff finds the Metal-Enclosed Bus Inspection Program acceptable to inspect loss of material due to general corrosion of the metal enclosed bus enclosure assemblies.

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 system components and provided information concerning how it will manage aging in the following areas:

- electrical equipment subject to EQ
- degradation of insulator quality due to salt deposits or surface contamination and loss of material due to mechanical wear
- loss of material due to wind-induced abrasion and fatigue, loss of conductor strength due to corrosion, and increased resistance of connection due to oxidation or loss of preload
- 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 further evaluation is recommended, the staff audited and reviewed the applicant's evaluation to determine whether it adequately addresses the issues further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.6.2.2. The staff's review of the applicant's further evaluations for those component groups follows.

3.6.2.2.1 Electrical Equipment Subject to Environmental Qualification

LRA Section 3.6.2.2.1 states that EQ is a TLAA, as defined in 10 CFR 54.3. Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(c)(1). SER Section 4.4 documents the staff's review of the applicant's evaluation of this TLAA.

3.6.2.2.2 Degradation of Insulator Quality Due to Salt Deposits or Surface Contamination and Loss of Material Due to Mechanical Wear

The staff reviewed LRA Section 3.6.2.2.2 against the criteria in SRP-LR Section 3.6.2.2.2.

SRP-LR Section 3.6.2.2.2 states that degradation of insulator quality due to salt deposits or surface contamination may occur in high-voltage insulators. The GALL Report recommends further evaluation of plant-specific AMPs for plants located where there are potential salt deposits or surface contamination (e.g., in the vicinity of salt water bodies or industrial pollution). Loss of material due to mechanical wear caused by wind on transmission conductors may occur in high-voltage insulators. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that these aging effects are adequately managed.

In LRA Section 3.6.2.2.2, the applicant stated that various airborne materials such as dust, salt, and industrial effluents can contaminate insulator surfaces. The buildup of surface contamination is gradual and in most areas washed away by rain. The glazed insulator surface aids this contamination removal. However, a large buildup of contamination enables the conductor voltage to track along the surface more easily and can lead to insulator flashover. Surface contamination can be a problem in areas where there are greater concentrations of airborne particles such as in the vicinity of facilities that discharge soot or near the sea coast where salt spray is prevalent. The applicant further stated that IP is not located near a sea coast where salt spray is prevalent, nor is IP located near a facility that discharges heavy pollutants. The applicant also stated that plant operating experience has not identified any issues associated with the buildup of surface contamination on the high-voltage insulators.

Since IP is not located near sources of industrial pollution or near the sea coast and the applicant's plant-specific operating experience has identified no issues associated with degradation of insulators, the staff finds that degradation of insulators due to salt deposit or surface contamination is not an applicable aging effect requiring management for high-voltage insulators at IP.

In the LRA, the applicant stated that mechanical wear is a potential aging effect for strain and suspension insulators subject to movement. Although this mechanism is possible, industry experience has shown that overhead transmission conductors do not normally swing. When subjected to a substantial wind, movement will subside after a short period. The applicant further stated that a review of IP operating experience determined that wear has not been apparent during routine inspection. Loss of material due to wear is not significant and will not cause a loss of intended function of the insulators.

The staff noted that although loss of material of insulators due to mechanical wear is possible, experience has shown that the transmission conductors do not normally swing significantly. When they do swing as the result of a substantial wind, they do not continue to swing for very long after the wind has subsided. Design and installation typically consider wind loading that can cause a transmission line and insulators to sway. The staff also noted that the applicant's routine inspections have not identified any loss of material of insulators due to mechanical wear. In addition, since the transmission conductors within the scope of license renewal at IP typically cover short spans, the surface areas exposed to wind loads are not significant. Therefore, the staff determines that the loss of material due to wear is not considered an aging effect that will cause a loss of intended function of the insulators at IP.

The staff finds that the applicant has addressed the potential degradation of insulator quality due to salt deposit or surface contamination and loss of materials due to mechanical wear. Based on the preceding technical justification, the staff concludes that the SRP-LR Section 3.6.2.2.2 criterion does not apply.

3.6.2.2.3 Loss of Material Due to Wind-Induced Abrasion and Fatigue, Loss of Conductor Strength Due to Corrosion, and Increased Resistance of Connection Due to Oxidation or Loss of Preload

The staff reviewed LRA Section 3.6.2.2.3 against the criteria in SRP-LR Section 3.6.2.2.3.

SRP-LR Section 3.6.2.2.3 states that loss of material due to wind-induced abrasion and fatigue, loss of conductor strength due to corrosion, and increased resistance of connection due to oxidation or loss of preload may 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 these aging effects are adequately managed.

SER Section 3.6.2.2.2 addresses the staff's review of loss of material due to wind-induced abrasion and fatigue for insulators.

The applicant stated in LRA Section 3.6.2.2.3 that the IP overhead transmission conductors subject to AMR are bounded by the Ontario Hydroelectric test population. The IP overhead transmission conductors have an ultimate strength margin greater than that of the Ontario Hydroelectric test cables after 80 years of service. The applicant also stated that the installation configuration at IP is representative of the tested samples, so the conclusions in the Ontario Hydro Study are valid for IP. However, the applicant did not provide information to substantiate the conclusion that the Ontario Hydroelectric Study is valid for IP. During the audit, the staff asked the applicant to explain in detail how the test conducted by Ontario Hydroelectric is valid for its plant (Audit Item 265). In a letter dated December 18, 2007, the applicant responded that corrosion in aluminum core steel-reinforced (ACSR) conductors is a very slow-acting mechanism and the corrosion rates depend on air quality, which includes suspended particles chemistry, sulfur dioxide (SO_2) concentration in air, precipitation, fog, chemistry, and meteorological conditions. Air quality in rural areas generally contains low concentrations of suspended particles and SO_2, which keeps the corrosion rate to a minimum. Although IP is located near urban areas, the applicant stated that there are no other industries in the immediate area. The applicant also stated that tests performed by Ontario Hydroelectric showed a 30 percent loss of an 80-year-old ACSR conductor due to corrosion. The IP transmission conductors for the 138-kV offsite power recovery are 1172-MCM aluminum conductor aluminum-reinforced (ACAR) 30/7 or 18/19 overhead transmission conductors. The Ontario Hydroelectric test did not include this specific conductor type, but these types are bounded because of the conductor size, configuration, and support strand material. The applicant further stated that the IP transmission cables have aluminum reinforcing strands, so the Ontario Hydroelectric ACSR transmission cables would bound the corrosion.

The staff reviewed the testing program performed by Ontario Hydroelectric to determine whether IP transmission conductors have adequate design margin. The study found that an 80-year-old ACSR conductor lost about 30 percent of conductor strength due to corrosion. A transmission conductor is replaced when it reaches a set percentage of composite conductor strength. The National Electrical Safety Code (NESC) requires that tension on installed conductors be a maximum of 60 percent of the ultimate conductor strength. The NESC also sets the maximum tension that a conductor must be designed to withstand under heavy load requirements, which consider ice, wind, and temperature. The staff reviewed the requirements for the specific conductors included in the AMR at IP. The conductors with the smallest ultimate strength margin (4/0 ACSR) will be used to illustrate this strength margin. The ultimate strength and the NESC heavy load tension requirements of 4/0 (212 MCM) ACSR are 8350 pounds (lb) and 2761 lb, respectively. This heavy load tension is 33 percent of the ultimate strength (2761 lb/8350 lb), which is within the 60 percent requirement. The margin between the NESC heavy load and the ultimate strength is 5589 lb; this is 67 percent of the ultimate strength margin. The Ontario Hydroelectric Study showed that an 80-year-old conductor lost 30 percent of composite conductor strength due to corrosion. In the case of the 4/0 ACSR transmission conductors, a 30 percent loss of ultimate strength would mean that there would still be an ultimate strength margin of 37 percent between the NESC requirement and the actual conductor strength. The 4/0 ACSR conductors have the lowest initial design margin among the transmission conductors included in the NESC. The IP transmission conductors are ACAR, so the corrosion would be less than that found in the Ontario Hydroelectric ACSR transmission conductors. The transmission conductors at IP2 and IP3 are 1172-MCM ACAR, which are bigger than the 212-MCM conductors as illustrated. This shows that transmission conductors at IP will have ample strength through the period of extended operation.

In LRA Section 3.6.2.2.3, the applicant stated that the design of the transmission conductor bolted connections at IP precludes torque relaxation and corrosion, and the plant-specific operating experience has not identified any failures of switchyard connection due to aging. The type of bolting plate and the use of Belleville washers are the industry standard to preclude torque relaxation. IP design incorporates the use of Belleville washers on bolted electrical connections of dissimilar metals to compensate for temperature changes, maintain the proper torque, and prevent loosening. This method of assembly is consistent with the good bolting practices recommended by industry guidelines (EPRI TR-104213, “Bolted Joint Maintenance & Application Guide,” issued December 1995). Before tightening of the connection, the bolted connections and washers are coated with an antioxidant compound (a grease-type sealant) to prevent the formation of oxides on the metal surface and to prevent moisture from entering the connection, thus reducing the chances of corrosion. The applicant stated that operating experience shows that this method of installation provides a corrosion-resistant, low-electrical-resistance connection. In addition, the applicant stated that the transmission connections are included in the infrared predictive maintenance of the 138-kV switchyard, which verifies the effectiveness of the connection design and installation practices. The infrared predictive maintenance is performed at least once every year. The applicant also stated that aluminum bus exposed to the service conditions of the switchyards does not experience any appreciable aging effects except minor oxidation, which does not impact the ability of the switchyard bus to perform its intended functions. In addition, the applicant stated that connection surface oxidation and loosening of bolted connections for aluminum switchyard bus are not applicable, since the switchyard bus connections are welded connections. However, the flexible conductors, which are welded to the switchyard bus, are bolted to the other switchyard components. The infrared predictive maintenance also includes these switchyard component connections.

The staff noted that connections to the switchyard bus are welded. However, the conductor connections are generally of the bolted category. Components in the switchyard are exposed to precipitation. Connection materials exposed to the service conditions of the switchyard do not experience any appreciable aging effects except minor oxidation of the exterior surfaces, which does not impact the ability of the switchyard bus to perform its intended function. The staff also noted that preload of bolted switchyard bus connections is maintained by the appropriate design and the use of lock and Belleville washers that absorb vibration and prevent loss of preload. Using an antioxidant compound (a grease-type sealant) before tightening the connection prevents the formation of oxides on the metal surface and prevents moisture from entering the connection, thus reducing the chances of corrosion. Industry operating experience shows that this method of installation provides a corrosion-resistance connection of low electrical resistance. The applicant stated that the connections at the switchyard are periodically evaluated via thermography as part of preventive maintenance. The staff concludes that the applicant has adequately addressed the aging mechanism of increased resistance of connections due to oxidation or loss of preload because the method of assembly is in accordance with EPRI TR-104213 recommendations which is consistent with the GALL Report; conductor bolted connections are subject to periodic thermography; and no adverse operating experience conditions exist at IP.

For those items that apply to LRA Section 3.6.2.2.3, the staff determined that the applicant has addressed loss of material, loss of conductor strength, and increased resistance connections or loss of preload. The staff concludes that the applicant has met the criteria of SRP-LR Section 3.6.2.2.3

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.

3.6.2.3 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 a line item in the GALL Report. The applicant provided further information about how it will manage the aging effects. Specifically, Note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation. The staff's evaluation is documented in the following sections.

3.6.2.3.1 Electrical and I&C Components - Summary of Aging Management Evaluation – LRA Tables 3.6.1 and 3.6.2-1

The staff reviewed LRA Table 3.6.2-1, which summarizes the results of AMR evaluations for the electrical and I&C system component groups.

In LRA Table 3.6.1, under Item 3.6.1-10, "Metal enclosed bus—Enclosure assemblies," the applicant stated that an AMR is not required for enclosure elastomers because they are consumables. Consumables are considered short-lived or periodically replaced. However, the staff noted that the GALL Report, Volume 2, Item VI.A-12, identifies elastomers as a commodity type that requires an AMP. Therefore, by letter dated April 29, 2008, in RAI 3.6.2.3-1, the staff asked the applicant to confirm that for the in-scope metal-enclosed buses, there are no other elastomers or gaskets other than the access door gaskets. For access door elastomers, the staff requested that the applicant provide a technical justification of the exclusion of these components from an AMR. In a letter dated May 28, 2008, the applicant stated that based on site documents, the in-scope 6.9-kV and the 480-volt (V) metal-enclosed buses do not contain elastomers, except for the gaskets that provide a seal around the edge of the access covers. The applicant further stated that during the period of extended operation, the access cover gasket will be replaced periodically in conjunction with preventive maintenance inspections. Since the access cover is replaced based on a specified time period, it is not subject to an AMR per 10 CFR 54.21(a)(1)(ii). The staff finds the applicant's response acceptable because, based on site documents, the in-scope 6.9-kV and the 480-V metal-enclosed buses do not contain elastomers, except for the gaskets that provide a seal around the edge of the access covers. During the period of extended operation, the access cover gasket will be replaced periodically in conjunction with preventive maintenance inspections. Since the access cover gasket is replaced based on a specified time period, it is not subject to AMR per 10 CFR 54.21(a)(1)(ii).

High-Voltage Power Cables

In LRA Table 3.6.2-1, the applicant stated that IP2 138-kV direct burial insulated transmission cables (passive electrical for station blackout recovery) have no aging effects requiring management. The applicant indicated (by Note J) for material, environment, aging effect, and AMP that neither the component nor the material and environment combination is evaluated in the GALL Report for meeting the component's intended electrical function. The plant-specific Note 602 for this item in LRA Table 3.6.2-1 states that it is not subject to water treeing, since it is designed for continuously wet conditions. Industry and plant operating experience has not provided any information on failures of this type of cable. In addition, in its December 18, 2007, response to the NRC Audit Item 266 concerning the qualification of this cable for continuous submerged condition, the applicant stated that the aging effects caused by moisture and voltage stress are not applicable to this cable because the lead sheath prevents moisture intrusion.

Pursuant to 10 CFR 54.21(a)(3), the applicant must demonstrate 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. Therefore, by letter dated May 28, 2008, in RAI 3.6.2.3-2, the staff requested that the applicant explain why an AMP is not required to manage the potential loss of dielectric strength leading to reduced insulation resistance and electrical failure due to aging mechanisms such as moisture and water intrusion, water treeing, elevated operating temperature, voltage stress, and galvanic corrosion. The staff also asked the applicant to provide details of the purchase specification and testing requirements of cables and to explain how the aging effects are managed for pot assemblies (termination ends of the cables).

In its response, dated June 26, 2008, the applicant provided its technical justification of why an AMP is not required to manage the potential loss of dielectric strength leading to reduced insulation resistance and electrical failure of the cables and its termination ends (pot assemblies). The applicant provided the following technical basis to show that the cables and their terminations are not susceptible to the aging effects caused by moisture intrusion, water treeing, elevated operating temperature, voltage stress, and galvanic corrosion because of the design features of cables:

- The main components of the IP2 138-kV solid dielectric transmission cables are an extruded 0.125-inch polyethylene (PE) jacket, a 0.125-inch lead sheath, copper woven fabric expanding (swellable) tape, an extruded insulation shield, cross-linked polyethylene (XLPE) insulation, an extruded conductor shield, and a compacted 750-MCM copper conductor. Radial water sealing is achieved by the corrosion-resistant lead sheath, and longitudinal water sealing is achieved with a water swelling material under the lead sheath. The IP2 cables are installed in a duct bank within the Buchanan substation. These cables are not installed in a continuously wet condition, but it is assumed that the cables are exposed to significant moisture (they are wet for more than a few days). Since the lead sheath prevents moisture intrusion into the XLPE insulation of the cables, the insulation will not develop water trees. There are no aging effects due to aging mechanisms such as moisture and water intrusion or water treeing. Since there are no aging effects, an AMP is not required. In addition, the design of the circuit precludes voltage stress that is not associated with moisture intrusion.

- Based on the plant drawing, the construction of the IP2 138-kV solid dielectric transmission cables is the same as that of a submarine cable without the layer of armor wires and its associated anticorrosion barrier. Therefore, the IP2 138-kV solid dielectric transmission cable is comparable to a submarine cable for protecting the dielectric insulation from exposure to moisture.

- The cable is designed for direct burial but is installed in an underground duct bank. The purchase specification for the cable required that the cable and joint design be impervious to both water and hydrocarbon-based liquids, so that neither water nor hydrocarbon-based liquids will have any deleterious effect on any part of the cable or joints.

- The cable design accounts for voltage stress caused by switching transients. The maximum operational voltage is 145 kV, and the cable rating is 245 kV. The minimum impulse withstand voltage for this cable is 815 kV, and the basic impulse level (BIL) rating is 650 kV. Since the cable rating is higher than the operational voltage and the minimum impulse withstand voltage is higher than the BIL rating, voltage stress will not create aging effects requiring management.

- The purchase specification required the solid dielectric cable system to meet the Association of Edison Illuminating Companies (AEIC) Specification CS7, “Specification for Crosslinked Polyethylene Insulated Shielded Power Cables Rated 69–138 kV.” The cable purchase specification required that the cable be supplied with a moisture barrier, which was a metallic (lead) sheath, and longitudinal water sealing with a water swelling material under the lead sheath. AEIC CS7 required the items to pass an initial high-potential proof test. The cable was tested at the manufacturing plant using 60-hertz alternating current voltage. The shielded cables were required to meet the corona extinction level voltage. The shielded cables were to be free of partial discharge at voltages well above operating voltages. The specifications and installation procedures specified receipt inspection and post-installation testing. In addition to these factory tests, the plant modification process required a direct current high-potential test after installation. The cable passed the AEIC CS7-87 test specifications.

- The conductor and the insulation have an extruded shield. The lead sheath is not in direct contact with another conducting material. Therefore, the potential galvanic corrosion associated with a submarine cable between the extruded lead sheath and the copper armor wires is not applicable to the IP2 cable, since there is not a layer of armor wires. Therefore, galvanic corrosion of the cable will not create aging effects requiring management.

- The IP2 138-kV solid dielectric transmission cable rating based on temperature considerations and installation method (including conductor configuration) is 575 amps continuous. The worst-case continuous load is about 330 amps. The worst-case continuous load is less than 60 percent of the rating of the cable, so ample design margin exists. Based on the available design margin, elevated operating temperature will not result in aging effects requiring management.

- The current maintenance program for the IP2 138-kV solid dielectric transmission cable performed by IP2 includes a walkdown of the IP2 138-kV offsite power feeder from the IP2 station auxiliary transformer to the Buchanan substation breakers. This walkdown includes inspection of the accessible portions of the 138-kV solid dielectric underground transmission cable. No periodic tests are performed under the IP2 maintenance program; however, IP2 continuously monitors these cables for voltage and load.

- Manufacturing defects or damage caused by shipping and installation are possible mechanisms contributing to water treeing and insulation breakdown; however, these are event-driven mechanisms not related to aging. Receipt inspections and post-installation testing minimize these conditions. These events result in premature failures, but the IP2 138-kV solid dielectric transmission cable, which was installed in late 1994, has experienced no such failures.

- The EPRI electrical handbook and Section XI.E3 of the GALL Report state that continuous wetting and continuous energization are not significant concerns for submarine cables, and the IP2 138-kV solid dielectric transmission cable has the same features as a submarine cable for preventing moisture intrusion. Therefore, no aging effects associated with moisture and voltage stress require management during the period of extended operation.

- The IP2 138-kV solid dielectric transmission cable has oil-filled pothead connections on each end. The potheads are sealed and filled with oil pressurized with a local nitrogen tank. A pressure switch that alarms in the Buchanan substation control room continuously monitors the pressure of the oil. The Buchanan substation control room alarm re-flashes in the IP2 control room. The oil in the pothead prevents moisture and oxygen intrusion into the connection but does not contribute to the BIL rating for the pothead, nor does the oil provide insulation for the connection. Therefore, the oil does not require a specific dielectric strength to support the connection's intended function. Because the oil prevents moisture and oxygen intrusion, corrosion of this connection is not an applicable aging mechanism. Furthermore, the applicant performs routine maintenance which entails periodic visual inspections of the potheads including the seals between the pothead and the 138-kV solid dielectric cables and between the pothead and the nitrogen connections. The applicant performs visual inspections of the potheads at least once per year. This visual inspection, combined with continuous monitoring, ensures the maintenance of an environment that precludes aging due to moisture and oxygen.

Based on review of the above information, the staff agrees that the IP2 138-kV XLPE cables have design features to prevent the potential loss of dielectric strength leading to reduced insulation resistance and electrical failure. However, the staff does not agree with the applicant's assessment that the IP2 cables do not require an AMP to manage the potential aging mechanism as discussed above during the period of extended operation. The staff notes that, as specified in GALL AMP XI.E3, Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, operating experience has shown that XLPE or high-molecular-weight polyethylene insulation materials are most susceptible to water tree formation. The formation and growth of water trees vary directly with operating voltage. These cables are installed in an environment where the cables could be submerged and/or in wet conditions.

The staff noted that IP2 neither has an existing program to inspect and remove water from the duct bank nor has proposed any such program for the period of extended operation. The applicant's response to Generic Letter 2007-01, "Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients," dated May 7, 2007 (ADAMS Accession number ML071350410), indicates that there were two 600-V cable failures that had lead jackets which were installed in a wet environment. For one of the table entries, the applicant lists the contributing cause to the degradation of the cable as submergence of cable for an extended period of time. In addition, the staff noted that licensees have reported several XLPE cable failures (shielded and non-shielded) in 5-kV, 8-kV, 15-kV, and 35-kV applications. Cable failures have a variety of causes, including exposure to electrical transients or aging effects caused by moisture intrusion and water treeing due to adverse abnormal environmental conditions during operation. Contributing causes, such as manufacturing defects or damage caused by shipping and installation, could initiate the aging effects. The likelihood of failure from any of these causes increases over time as the cable insulation degrades.

The staff determined that IP2 cable life depends on the dielectric properties and that the applicant needs to address how it plans to monitor the degradation and manage the aging effects during the period of extended operation. In addition, neither the vendor nor the applicant has established any qualified life for these cables.

To address the staff's concern, the applicant stated that it would revise its aging management evaluations in an amendment to the LRA. In a letter dated August 14, 2008, the applicant amended the LRA to state that LRA Sections A.2.1.28 and B.1.29 were modified to add the 138-kV underground transmission cable, which is part of the Unit 2 offsite power path, to the Periodic Surveillance and Preventive Maintenance Program. The routine maintenance will include vendor-recommended testing and inspections as stated in the amended text for LRA Sections A.2.2.28 and B.1.29. SER Section 3.0.3.3.7 documents the staff's evaluation of the applicant’s Periodic Surveillance and Preventive Maintenance Program.

The staff’s concerns identified in RAI 3.6.2.3-2 are resolved because the applicant has established an AMP to manage the potential loss of dielectric strength leading to reduced insulation resistance and electrical failure of the cables and its termination ends.

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 functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the electrical and I&C system components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.7 Conclusion for Aging Management Review Results

The staff reviewed the information in LRA Section 3, “Aging Management Review Results,” and LRA Appendix B, “Aging Management Programs and Activities.” On the basis of its review of the AMR results and AMPs, the staff concludes that the applicant has demonstrated that the aging effects will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the applicable UFSAR supplement program summaries and concludes that the 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 licenses will continue to be conducted in accordance with the CLB, and any changes made to the CLB, in order to comply with 10 CFR 54.21(a)(3), are in accordance with 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) addresses the identification of time-limited aging analyses (TLAAs). In Sections 4.2 through 4.7 of the license renewal application (LRA), Entergy Nuclear Operations, Inc. (Entergy or the applicant) addressed the TLAAs for Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3). SER Sections 4.2 through 4.8 document the review of the TLAAs conducted by the staff of the U.S. Nuclear Regulatory Commission (NRC or the staff).

TLAAs are certain plant-specific safety analyses that involve time-limited assumptions defined by the current operating term. Pursuant to Title 10, Section 54.21(c)(1), of the *Code of Federal Regulations* (10 CFR 54.21(c)(1)), applicants must list TLAAs as defined in 10 CFR 54.3, “Definitions.”

In addition, pursuant to 10 CFR 54.21(c)(2), applicants must list plant-specific exemptions granted under 10 CFR 50.12, “Specific Exemptions,” based on TLAAs. For any such exemptions, the applicant must evaluate and justify the continuation of the exemptions for the period of extended operation.

4.1.1 Summary of Technical Information in the Application

To identify the TLAAs, the applicant evaluated calculations for IP2 and IP3 against the six criteria specified in 10 CFR 54.3. The applicant indicated that it has identified the calculations that met the six criteria by searching the current licensing basis (CLB). The CLB includes the updated final safety analysis report (UFSAR), technical specifications, the technical requirements manual, fire protection program documents, NRC safety evaluation reports, licensing correspondence, and applicable vendor reports. In LRA Table 4.1-1, “List of IP2 TLAA and Resolution,” and LRA Table 4.1-2, “List of IP3 TLAA and Resolution,” the applicant listed the following applicable TLAAs:

- reactor vessel (RV) neutron embrittlement analyses
- metal fatigue analyses
- environmental qualification (EQ) analyses of electrical equipment
- concrete containment tendon prestress analyses
- containment liner plate and penetrations fatigue analyses
- leak before break (LBB)
- steam generator flow-induced vibration

Pursuant to 10 CFR 54.21(c)(2), the applicant stated that it did not identify exemptions granted under 10 CFR 50.12 based on a TLAA, in accordance with 10 CFR 54.3.

4.1.2 Staff Evaluation

LRA Section 4.1 lists the IP2 and IP3 TLAAs. The staff reviewed the information to determine whether the applicant had provided sufficient information pursuant to 10 CFR 54.21(c)(1) and 10 CFR 54.21(c)(2).

As defined in 10 CFR 54.3, TLAAs meet the following six criteria:

(1) involve systems, structures, and components within the scope of license renewal, pursuant to 10 CFR 54.4(a)

(2) consider the effects of aging

(3) involve time-limited assumptions defined by the current operating term (40 years)

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

(5) involve conclusions, or provide the basis for conclusions, related to the capability of the system, structure, and component to perform its intended functions, pursuant to 10 CFR 54.4(b)

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

The applicant reviewed the list of common TLAAs in "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR), issued September 2005. The applicant listed TLAAs applicable to IP2 and IP3 in LRA Tables 4.1-1 and 4.1-2.

As required by 10 CFR 54.21(c)(2), the applicant must list all exemptions granted in accordance with 10 CFR 50.12, based on TLAAs, and evaluated and justified for continuation through the period of extended operation. The LRA states that each active exemption was reviewed to determine whether it was based on a TLAA. The applicant did not identify any TLAA-based exemptions. Based on the information provided by the applicant regarding the results of the applicant's search of the CLB to identify these exemptions, the staff has determined, in accordance with 10 CFR 54.21(c)(2), that there are no TLAA-based exemptions which have been justified for continuation through the period of extended operation.

4.1.3 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable list of TLAAs, as required by 10 CFR 54.21(c)(1), and that no exemptions have been granted on the basis of a TLAA for which continuation has been justified during the period of extended operation as specified in 10 CFR 54.21(c)(2).

4.2 Reactor Vessel Neutron Embrittlement

The regulations governing RV integrity are in 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities." As required by 10 CFR 50.60, "Acceptance Criteria for Fracture Prevention Measures for Lightwater Nuclear Power Reactors for Normal Operation," all light-water reactors meet the fracture toughness, pressure-temperature (P-T) limits, and material surveillance program requirements for the reactor coolant pressure boundary pursuant to Appendices G, "Fracture Toughness Requirements," and H, "Reactor Vessel Material Surveillance Program Requirements," to 10 CFR Part 50. In addition, 10 CFR 50.61, "Fracture

Toughness Requirements for Protection against Pressurized Thermal Shock Events," requires that all pressurized-water nuclear power reactors meet specific screening criteria for protection against RV failure from pressurized thermal shock (PTS) events. The applicant's CLB analyses of RV fracture toughness reduction for 40 years are TLAAs.

A summary of the RV neutron embrittlement TLAA for each unit follows. Forty-eight effective full-power years (EFPY) are projected for the end of the period of extended operation (60 years) based on actual capacity factors from the start of commercial operation until 2005 and on a projected average capacity factor of 95 percent from 2005 until the end of the period of extended operation.

4.2.1 Reactor Vessel Fluence

4.2.1.1 Summary of Technical Information in the Application

LRA Section 4.2.1 summarizes the evaluation of RV neutron fluence for the period of extended operation, projecting neutron exposure levels for the RVs for an operating period extending to 48 EFPYs. These calculations utilized discrete ordinates (S_n) transport analysis to determine the neutron radiation environment within the RV and the surveillance capsules.

The IP2 evaluation calculated plant- and fuel-cycle-specific exposure parameters of fast neutron fluence (E > 1.0 million electron volts (MeV)) and iron atom displacements for the first 16 reactor operating cycles (1973–2004). The fuel cycle designs analyzed in these calculations have been implemented. The calculations also included analyses for three other cycle designs created as part of the 2003 stretch power uprate study; therefore, the 48-EFPY projections included the effects of stretch power uprate. The projected 48-EFPY peak beltline neutron fluence level of 1.906×10^{19} neutrons per square centimeter (n/cm^2)(at the 45-degree azimuth position) is for all beltline materials except axial welds, which are located at 0-, 15-, and 30-degree azimuth positions. The maximum projected 48-EFPY peak fluence level for the beltline axial welds is 1.295×10^{19} n/cm^2 at the 30-degree azimuth position. The one-fourth of the way through the vessel wall (¼T) neutron fluence level was determined by applying Equation (3) of Regulatory Guide (RG) 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," issued May 1988, to an RV thickness of 8.625 inches, yielding a neutron fluence of 7.72×10^{18} n/cm^2 for beltline axial welds and 1.136×10^{19} n/cm^2 for all other beltline materials.

The IP3 evaluation calculated plant- and fuel-cycle-specific exposure parameters of fast neutron fluence (E > 1.0 MeV) and iron atom displacements for the first 13 reactor operating cycles (1976–2005). The fuel cycle designs analyzed in these calculations have been implemented. The calculations also included analyses for three other cycle designs created as parts of the 2003 stretch power uprate study; therefore, the 48-EFPY projections include the effects of the stretch power uprate. The projected 48-EFPY peak beltline neutron fluence level of 1.560×10^{19} n/cm^2 (at the 45-degree azimuth position) is for all beltline materials including axial welds. The ¼T neutron fluence level was determined by applying RG 1.99, Revision 2, Equation (3) to an RV thickness of 8.625 inches, yielding a neutron fluence of 9.298×10^{18} n/cm^2.

4.2.1.2 Staff Evaluation

Neutron Fluence for RV Surveillance Capsules. The staff reviewed the applicant's evaluations of the RV surveillance capsules for the materials in the RV of IP2 as described in the following reports:

- Westinghouse Commercial Atomic Power (WCAP)-15629, Revision 1, "Indian Point Unit 2 Heatup and Cooldown Curves for Normal Operation and PTLR Support Documentation"
- WCAP-16251, "Analysis of Capsule X from Entergy's Indian Point Unit 3 Reactor Vessel Radiation Surveillance Program"
- WCAP-15805, "Analysis of Capsule X from the Carolina Power and Light Company H.B. Robinson Unit 2 Reactor Vessel Radiation Surveillance Program"

WCAP-15629, Revision 1, is contained in a January 11, 2002, letter from Entergy. WCAP-16251 is contained in a July 29, 2004, letter from Entergy. WCAP-15805 is contained in an April 25, 2002, letter from Carolina Power and Light Company. WCAP-16251, Section 6; WCAP-15805, Section 6; and WCAP-15629, Revision 1, Appendix B, describe the methodology used for determining the neutron fluence for the surveillance capsules. The staff finds that the methodology documented in WCAP-16251, Section 6; WCAP-15805, Section 6; and WCAP-15629, Revision 1, Appendix B, is acceptable because (1) it has been extensively benchmarked as described in WCAP-15557, "Qualification of Westinghouse Pressure Vessel Neutron Fluence Evaluation Methodology"; (2) it adheres to the guidance in RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," issued March 2001; and (3) it uses plant-specific dosimetry results to provide additional plant-specific validation of the generic benchmarking in WCAP-15557.

The staff reviewed the applicant's evaluations of the RV surveillance capsules for the materials in the RV of IP3 as described in report WCAP-16251. The staff finds the methodology in WCAP-16251 acceptable as discussed above.

Neutron Fluence for Reactor Vessel. In LRA Section 4.2.1, the applicant provided its peak beltline fluence level for 48 EFPY for IP2 and IP3. Since the Charpy upper-shelf energy (USE) and pressurized thermal shock (PTS) analyses utilize the neutron fluence at 48 EFPY to represent the neutron fluence for the reactor vessels at the end of the period of extended operation, the staff requested additional information regarding (a) what capacity factors and neutron flux were assumed for each unit from the last refueling outage to the end of the period of extended operation to result in 48 EFPY at the end of the period of extended operation, and why these capacity factors and neutron flux values are applicable for determining the neutron fluence for the reactor vessels at the end of the period of extended operation; and (b) how future capacity factors, neutron flux and neutron fluence values will be monitored to ensure 48 EFPY values bound the actual conditions of the reactor vessels at the end of the period of extended operation. In its November 28, 2007 response to the request for additional information (RAI) 4.2.1-1, the applicant described the impact of plant operation on the RV neutron fluence and the method of monitoring the EFPY and neutron fluence. The applicant stated the following:

> Neutron flux corresponding to the licensed reactor power rating was assumed from the end of the last refueling outage through the end of the period of

extended operation. A two-year cycle (730 days), includes a 25-day refueling outage (705 operating days). IP2 would have to operate at a capacity factor of 0.99 during the periods between refueling outages to attain 48 EFPY at the end of the period of extended operation (September 13, 2033).

IP3 would have to operate at a capacity factor of greater than 1.0 during the periods between refueling outages to attain 48 EFPY at the end of the period of extended operation (December 15, 2035).

Future neutron fluence values will be monitored to ensure 48 EFPY values bound the actual conditions of the reactor vessels in the same way current neutron fluence is monitored to ensure P-T curves remain valid. Plant service lifetime in EFPY is routinely reviewed by engineering and licensing personnel. Additionally, accumulated reactor vessel fluence is checked on a cyclic basis as part of the core reload change package. Because of shutdowns for refueling, plant operation cannot exceed 48 EFPY. If rated power level is increased at a future date, the associated engineering evaluations will ensure the resulting increase in flux is properly accounted for in determining the neutron fluence for the reactor vessels at the end of the period of extended operation.

During a telephone call with the applicant on December 3, 2007, the staff explained that in RAI 4.2.1-1 regarding neutron fluence and flux, the staff was asking for specific fluence and flux values and the source of those calculated values and requested that this information be provided. In addition, the NRC staff requested that Entergy provide confirmation that the referenced source of the surveillance data satisfies the guidance Regulatory Guide 1.190, and that the surveillance data have been used in the PTS and Charpy USE analyses.

By letter dated January 17, 2008, the applicant supplemented its response to RAI 4.2.1-1, and identified the neutron fluxes assumed for all future operating cycles. However, the January 17, 2008 response did not identify the methodology for determining the neutron fluxes for the RV in IP2. In a subsequent telephone conference call held on May 7, 2008, the applicant indicated that it utilized the neutron fluence calculation methodology documented in WCAP-16157-P, “Indian Point Nuclear Generating Unit No. 2 Stretch Power Uprate NSSS and BOP Licensing Report,” issued January 2004. This report references WCAP-15629, Revision 1. Since the methodology for calculating neutron fluence in WCAP-15629, Revision 1, is acceptable for the reasons specified earlier in this section, the neutron fluence calculated by the applicant for the IP2 RV is acceptable. Similarly, since the applicant calculated the neutron fluxes for the RV in IP3 using the methodology documented in WCAP-16251, Section 6, the staff finds the fluence calculations acceptable.

The capacity factor is the ratio of the number of full-power days of operation to the number of calendar days per fuel cycle. A 2-year cycle with 705 days of full-power operation and 25 days of refueling would result in a capacity factor of 0.97. Using the neutron flux reported by the applicant, the staff confirmed that the applicant would have to exceed a capacity factor of 0.99 during future cycles to reach the neutron fluences that are reported for the RVs in IP2 and IP3 in LRA Tables 4.2-1 through 4.2-6. LRA Tables 4.2-1 and 4.2-2 provide the neutron fluences for the RV materials for the Charpy upper-shelf energy (USE) evaluations for IP2 and IP3, respectively. LRA Tables 4.2-3 and 4.2-4 provide the neutron fluence for the PTS evaluations for IP2 and IP3, respectively. LRA Tables 4.2-5 and 4.2-6 provide the neutron fluence for adjusted reference temperature for IP2 and IP3, respectively. Since normal plant operation would only result in a capacity factor of 0.97 and the applicant monitors the EFPY and neutron fluence, the staff finds that the neutron fluences documented in LRA Tables 4.2-1 through 4.2-6 are acceptable for evaluating the impact of neutron radiation on RV integrity.

The staff requested that the applicant evaluate the effect of neutron fluence at the end of the period of extended operation on the IP2 and IP3 nozzle shell courses. In a letter dated September 24, 2008, the applicant determined the impact of neutron fluence on the plates, welds, and nozzle forgings in the IP2 and IP3 nozzle shell courses. The neutron fluence for the IP3 shell course was projected using the results of the IP2 analysis. The results of the IP2 analysis are applicable to IP3 since the IP2 and IP3 vessel geometries are the same, and the applicant uses similar fuel loading patterns. The outlet and inlet nozzle-to-shell welds were determined to have neutron fluences of less than 1×10^{17} n/cm^2 (E > 1.0 MeV) at the end of the period of extended operation. Since RG 1.99, Revision 2 indicated that neutron fluence values of less than 1×10^{17} n/cm^2 (E > 1.0 MeV) do not result in significant radiation embrittlement, licensees do not need to evaluate the impact of radiation embrittlement on components whose neutron fluence is less than 1×10^{17} n/cm^2 (E > 1.0 MeV). In its letter dated September 24, 2008, the applicant indicated that the nozzle shell plates, nozzle shell longitudinal welds, and the nozzle-to-intermediate shell circumferential weld in the IP2 and IP3 vessels would have neutron fluence values greater than 1×10^{17} n/cm^2 (E > 1.0 MeV) at the end of the period of extended operation. Therefore, the applicant included these components in its Charpy USE and PTS evaluations. The staff's evaluation of the applicant's Charpy USE evaluation of these components and of the PTS evaluation is documented in SER Sections 4.2.2.2 and 4.2.5.2, respectively.

In its September 24, 2008 letter, the applicant committed to update the neutron fluence calculations should there be changes in the fuel loadings that do not support the assumed similarities for the projection of the vessel fluences for future cycle loadings through the end of the period of extended operation (Commitment 38). This is acceptable.

4.2.1.3 UFSAR Supplement

The applicant provided an UFSAR supplement summary description of its TLAA evaluation of RV neutron fluence in LRA Sections A.2.2.1 and A.3.2.1, as amended by letter dated June 11, 2008, and A.2.2.1.1 and A.3.2.1.1. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address RV neutron fluence is adequate.

4.2.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for reactor vessel neutron fluence, the analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.2 Charpy Upper-Shelf Energy

4.2.2.1 Summary of Technical Information in the Application

LRA Section 4.2.2 summarizes the evaluation of Charpy USE for the period of extended operation. Appendix G to 10 CFR Part 50 requires the applicant to ensure that the reactor coolant pressure boundary pressure-retaining components made of ferritic materials meet American Society of Mechanical Engineers (ASME) Code fracture toughness requirements, as supplemented, during system hydrostatic tests and any condition of normal operation, including anticipated operational occurrences. For RV beltline materials, reference temperature nil ductility (RT_{NDT}) and Charpy USE values must account for the effects of neutron radiation, determined by consideration of the neutron fluence at the deepest point on the crack front of the flaw assumed in the analysis. RV beltline materials must maintain Charpy USE values of no less than 50 foot-pounds (ft-lb) throughout the life of the vessel. RG 1.99, Revision 2, provides two methods (positions) for determining Charpy USE. Position 1 applies to material with no surveillance data available. Position 2 applies to material with surveillance data. Position 1 determines the percent drop in Charpy USE for a stated copper content and neutron fluence by reference to RG 1.99, Revision 2, Figure 2, in accordance with RG 1.99, Revision 2, Section 1.2. This percentage drop is then applied to the initial Charpy USE value to obtain the adjusted Charpy USE value. Position 2 determines the percent drop in Charpy USE by plotting the available data on Figure 2 and fitting the data with a line parallel to the predetermined lines bounding all the plotted points in accordance with Section 2.2 of RG 1.99, Revision 2.

For IP2, the applicant stated that the Charpy USE values were based on the maximum projected 48-EFPY beltline fluence. The beltline region chemistry and surveillance data, including the unirradiated Charpy USE values, were from the second Reactor Vessel Integrity Database (RVID2) and clarified in WCAP-15629, Revision 1. The projected 48-EFPY peak beltline neutron fluence level at the clad-base metal interface of 1.906×10^{19} n/cm^2 was applied to all beltline materials except the RV axial welds, where the expected peak fluence was 1.295×10^{19} n/cm^2. LRA Table 4.2-1 shows the resulting projected 48-EFPY Charpy USE drop and resulting ¼T Charpy USE. One intermediate shell plate (B2002-3) and one lower shell plate (B2003-1) have projected USE values that fall below 50 ft-lb during the period of extended operation. All remaining plate and weld beltline materials exceed 50 ft-lb at 48 EFPY. Section IV.A.1 of Appendix G to 10 CFR Part 50, requires licensees to take action when the 50 ft-lb end-of-life (EOL) USE criterion cannot be met. The lowest projected IP2 beltline plate material USE value through the period of extended operation was 47.4 ft-lb for intermediate shell plate B2002-3. An equivalent margins analysis, described in WCAP-13587, Revision 1, “Reactor Vessel Upper-Shelf Energy Bounding Evaluation for Westinghouse Pressurized Water Reactors,” demonstrated that the minimum acceptable USE value for RV plate material in 4-loop plants like IP2 is 43 ft-lb. In the WCAP-13587, Revision 1, safety assessment, the staff concluded that the report demonstrated margins of safety equivalent to those of the ASME Code for beltline plate and forging materials. The IP2 USE values were acceptable because the projected 47.4 ft-lb lowest USE level for the IP2 beltline plate material through the period of extended operation for intermediate shell plate B2002-3 was above the 43 ft-lb minimum acceptable USE value for 4-loop plants as demonstrated in WCAP-13587, Revision 1. Furthermore, these values were consistent with SRP-LR, Section 4.2.2.1.1.2, and the H.B. Robinson, Unit 2, SER, as documented in NUREG-1785, “Safety Evaluation Report Related to the License Renewal of H.B. Robinson Steam Electric Plant, Unit 2,” issued March 2004.

For IP3, the applicant stated that the USE values were based on the maximum projected 48 EFPY beltline fluence and the beltline region chemistry and surveillance data, including the unirradiated percent drop in Charpy USE information summarized in the RVID2 database, with the projected 48-EFPY peak beltline fluence level of 1.560×10^{19} n/cm^2 at the clad-base metal interface conservatively applied to all beltline materials. The applicant's calculation of the 48 EFPY, ¼T neutron fluence level of $9.298x^{18}$ n/cm^2 was in accordance with RG 1.99, Equation (3), based on a vessel thickness of 8.625 inches. LRA Table 4.2-2 displays the resulting projected 48-EFPY Charpy USE drop and resulting ¼T Charpy USE values. All plate and weld beltline materials exceed 50 ft-lb at 48 EFPYs and an equivalent margins analysis is not required.

The applicant stated that the TLAAs for USE are projected through the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

4.2.2.2 Staff Evaluation

The staff reviewed LRA Section 4.2.2 to verify that, pursuant to 10 CFR 54.21(c)(1)(ii), the analyses have been projected to the end of the period of extended operation.

<u>Charpy Upper-Shelf Energy Evaluation</u>. LRA Table 4.2-3 indicates that the ΔRT_{NDT} value caused by irradiation for the intermediate shell axial welds and the lower shell axial welds in IP2 were determined using surveillance data reported in WCAP-15629, Revision 1, "Indian Point Unit 2 Heatup and Cooldown Limit Curves for Normal Operation and PTLR Support Documentation." By letter dated October 29, 2007, the staff asked the applicant to provide neutron fluence values derived using a methodology that satisfies the guidance in RG 1.190, and to provide the surveillance data analysis required by 10 CFR 50.61(c)(2)(i).

By letter dated November 28, 2007, the applicant responded to the staff's RAI and stated that the fluences shown are based on the data taken before the RG 1.190 guidance was available. Therefore, Westinghouse used the information at hand and added a 15 percent penalty for a conservative margin. Revised fluences consistent with the guidance of RG 1.190 have been calculated by Westinghouse. In a telephone conference call with the applicant on December 4, 2007, the staff asked that Entergy provide confirmation that the referenced source of the surveillance data satisfies Regulatory Guide 1.190, and that the surveillance data have been used in the Pressurized Thermal Shock and Charpy Upper-Shelf Energy analyses.

By letter dated January 17, 2008, the applicant provided updated surveillance data for IP2 intermediate shell plates B2002-1, B2002-2, and B2002-3. WCAP-15629, Revision 1, Table C-1, reports the updated surveillance data. As a result of these data, the applicant revised the Charpy USE value for the limiting material, plate B2002-3 (LRA Table 4.2-1 in the January 17, 2008, letter), to 48.3 ft-lb at the end of the period of extended operation. The Charpy USE was projected using the methodology in RG 1.99, Revision 2, Section 2.2. To maximize the accuracy of the projection, the applicant used a spreadsheet and the equations for the RG 1.99, Revision 2, curves (available in NUREG/CR-5799, "Review of Reactor Pressure Vessel Evaluation Report for Yankee Rowe Nuclear Power Station [YAEC No. 1735]," issued March 1992) to determine the percent drop in Charpy USE. The other beltline plates, B2003-1 and B2003-2, do not have surveillance data and have projected Charpy USE using the methodology in RG 1.99, Revision 2, Section 1.2.

The January 17, 2008, letter also provided an updated analysis for the Charpy USE for the intermediate shell axial welds and lower shell axial welds in IP2 at the end of the period of extended operation. Using the methodology in RG 1.99, Revision 2, Section 2.2, the applicant projected that these welds will have a Charpy USE value of 60.8 ft-lb at the end of the period of extended operation. Combustion Engineering fabricated these welds using Linde 1092 flux and heat number W5214 weld wire. The IP2, IP3, and H.B. Robinson RVs all contain this weld material in their surveillance capsules. WCAP-15629, Revision 1, Table C-1, documents the IP2 Charpy USE surveillance data. WCAP-16251-NP, Table 5-10, documents the IP3 Charpy USE surveillance data. WCAP-15805, Table 5-10, documents the H.B. Robinson Charpy USE surveillance data. The staff confirmed that the Charpy USE values reported in the applicant's January 17, 2008, letter for all beltline plates and welds in the IP2 RV were calculated in accordance with RG 1.99, Revision 2.

In its January 17, 2008, response to RAI 4.2.2-1, the applicant provided updated surveillance data and analysis for IP3 intermediate shell plate B2803-3. WCAP-16251-NP, Table 5-10, documents the updated surveillance. Using the methodology documented in RG 1.99, Revision 2, Section 2.2, the revised Charpy USE value for plate B2803-3 is 49.8 ft-lb at the end of the period of extended operation. Since plate B2803-3 is projected to be below 50 ft-lb, an equivalent margins analysis is required to demonstrate that it will provide margins of safety against fracture equivalent to those required by ASME Code, Section XI, Appendix G. The other beltline plates and welds do not have surveillance data and have Charpy USE values greater than 50 ft-lb at the end of the period of extended operation. Since there are no surveillance data for these plates and welds, the Charpy USE is projected using the methodology in RG 1.99, Revision 2, Section 1.2. The staff confirmed that the Charpy USE values reported in the applicant's January 17, 2008, letter for all IP3 RV beltline plates and welds were calculated in accordance with RG 1.99, Revision 2.

In a letter dated September 24, 2008, the applicant stated that the Charpy USE values for the nozzle shell plates, nozzle-to-shell longitudinal welds, and the nozzle-to-intermediate shell circumferential weld in the IP2 and IP3 vessels would be greater than 50 ft-lb at the end of the period of extended operation. These values were determined using the methodology documented in RG 1.99, Revision 2. Since the Charpy USE values are greater than 50 ft-lb, an equivalent margins analysis is not required and these components meet the requirements of Section IV.A.1.a of Appendix G to 10 CFR Part 50 for Charpy USE.

Equivalent Margins Analyses. Section IV.A.1.a. of Appendix G to 10 CFR Part 50 requires that RV beltline materials have Charpy USE values in the transverse direction for base metal and along the weld for weld metal of no less than 50 ft-lb throughout the life of the RV, unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy USE will provide margins of safety against fracture equivalent to those required by ASME Code, Section XI, Appendix G. In its January 17, 2008 letter, the applicant indicated that the analysis performed in WCAP-13587, Revision 1, demonstrated that the minimum acceptable Charpy USE value for RV plate material in 4-loop plants such as IP2 and IP3 is 43 ft-lb. The applicant asserted that IP2 and IP3 RVs were acceptable because the lowest Charpy USE values at the end of the period of extended operation in these RVs (48.3 ft-lb for IP2 and 49.8 ft-lb for IP3) are greater than the 43 ft-lb minimum acceptable Charpy USE for 4-loop plants determined in WCAP-13587, Revision 1.

The applicant submitted WCAP-13587, Revision 1, for staff review and approval to demonstrate through fracture mechanics analyses that margins of safety against fracture exist that are equivalent to those required by ASME Code, Section XI, Appendix G, for beltline materials having Charpy USE values below the 50 ft-lb screening limit as required by 10 CFR Part 50, Appendix G, Section IV.A.1.a. The analysis in WCAP-13587, Revision 1, establishes a minimum acceptable Charpy USE value of 43 ft-lb for RVs in 4-loop Westinghouse designed plants. The staff reviewed WCAP-13587, Revision 1, in a safety assessment included in a letter dated April 21, 1994, to W.H. Rasin of the Nuclear Management and Resources Council. The staff concluded that the methodology employed in the report was consistent with the guidelines in ASME Code Case N-512, "Assessment of Reactor Vessels with Low Upper-Shelf Charpy Impact Energy Levels," and draft RG, DG-1023, "Evaluation of Reactor Pressure Vessels with Charpy Upper-Shelf Energy Less than 50 Ft-Lb," issued September 1993, and that the report demonstrates the margins of safety equivalent to those of the ASME Code. ASME Code Case N-512 provides criteria for demonstrating that RVs with Charpy USE values of less than 50 ft-lb have margins of safety against fracture equivalent to those required by ASME Code, Section XI, Appendix G. ASME Code Case N-512 requires that flaws be postulated in the RV at locations of predicted low Charpy USE and that the applied J-integral ($J_{applied}$) for these flaws be calculated and compared with the J-integral ($J_{material}$) fracture resistance of the material. The applicant calculated $J_{applied}$ for generic ASME Code Service Loading A, B, C, and D conditions and generic RV shell geometry. The $J_{material}$ was calculated using J-R data for the RV materials.

The staff's safety assessment for WCAP-13587, Revision 1 indicated that licensees must confirm that the bounding plate used in the report has a lower J-R curve than any beltline material in their RV. This safety assessment indicated that the J-R curve data proposed in WCAP-13587, Revision 1, for A533 Grade B plate and A302 Grade B modified (with nickel added) base materials were acceptable.

To demonstrate that the analyses in WCAP-13587, Revision 1, were applicable to IP2 and IP3, the staff, in RAI 4.2.2-2 dated October 29, 2007, requested that the applicant compare (1) the plate materials in the IP2 and IP3 RVs to the plate materials evaluated in WCAP-13587, Revision 1, (2) the RV shell geometry (wall thickness and inner radius) of the IP2 and IP3 RVs to the geometry used in the Westinghouse 4-loop analysis in WCAP-13587, Revision 1, and (3) the ASME Code Service Loading A, B, C, and D conditions for IP2 and IP3 to the ASME Code Service Loading A, B, C, and D conditions evaluated in WCAP- 13587, Revision 1. The comparison of the RV geometry and transient conditions provides the basis for determining that the applied driving force ($J_{applied}$) in the WCAP-13587, Revision 1, analysis is applicable to the IP2 and IP3 RVs.

The applicant's response to RAI 4.2.2-2 indicated (1) that the IP2 RV beltline plate material was SA-302, Grade B modified (ASME Code Case 1339); (2) that the inside diameter was the same as that used in the WCAP-13587, Revision 1, analyses and the nominal wall thickness (8.625 inches) for the IP2 RV is greater than the values used in the WCAP-13587, Revision 1, analyses; (3) the cooldown rate for the IP2 RV (note: Technical Specification Figure 3.4.3-2, License Amendment No. 238, limits the maximum cooldown rate for IP2 to 100 °Fahrenheit per hour (°F/hr)) which is the same cooldown rate (100 °F/hr) used to evaluate ASME Code Service Loading A and B conditions that was evaluated in WCAP-13587, Revision 1; and (4) the analyses in Chapter 14 of the final safety analysis report for IP2 are bounded by the conditions for the ASME Code Service Loading C and D conditions (small steamline break for Loading C condition and large steamline break for Loading D condition) that were evaluated in WCAP-13587, Revision 1. Based upon the above comparison, the applicant indicated that the evaluation provided in WCAP-13587, Revision 1, is applicable to the IP2 RV. The applicant provided a similar analysis for the IP3 RV in a response to RAI 4.2.2-2 in a letter dated June 11, 2008, although the June 11, 2008, response does not discuss the materials in the IP3 RV. In subsequent phone calls, on July 8 and 11, 2008, the applicant confirmed that the plate materials in IP3 meet the same ASME Code case and Combustion Engineering specification as those in IP2, and that WCAP-13587, Revision 1, is applicable to the plate materials in IP3.

Since the applicant projected that (1) limiting plates B2002-3 in the IP2 RV and B2803-3 in the IP3 RV would have greater Charpy USE values (48.3 ft-lb and 49.8 ft-lb, respectively) at the end of the period of extended operation than the minimum acceptable Charpy USE value (43 ft-lb) in WCAP-13587, Revision 1, for RVs in 4-loop Westinghouse-designed plants; and (2) the evaluation provided in WCAP-13587, Revision 1, is applicable to the IP2 RV and the IP3 RV, the applicant has demonstrated that the staff's conclusions in its safety evaluation for WCAP-13587, Revision 1, are applicable to the IP2 and IP3 RVs.

Regulatory Guide 1.161, "Evaluation of Reactor Pressure Vessels with Charpy Upper-Shelf Energy Less Than 50 Ft-Lb," issued June 1995, supersedes DG-1023. In addition, 10 CFR 50.55a(b)(2), "Codes and Standards," approves the use of the 2001 Edition through the 2003 addenda of Section XI of the ASME Code. This edition and addenda of the ASME Code contains criteria for evaluating RVs with low Charpy USE values. Specifically, Appendix K, "Assessment of Reactor Vessels with Low Upper Shelf Charpy Impact Energy Levels," to Section XI of the ASME Code contains the criteria. Appendix K to Section XI of the ASME Code supersedes ASME Code Case N-512. To demonstrate that the methodology and criteria in its equivalent margins analyses for the IP2 and IP3 RVs are equivalent to the methodology and criteria in RG 1.161 and Appendix K to Section XI of the ASME Code, the applicant, in a letter dated June 11, 2008, compared the methodology and criteria in its equivalent margins analyses for the IP2 and IP3 RVs to the methodology and criteria in RG 1.161 and Appendix K to Section XI of the ASME Code. The applicant concluded that the analysis documented in WCAP-13587, Revision 1, did not deviate from the methods and formulas cited in RG 1.161 and Appendix K to Section XI of the ASME Code.

The staff compared the methods and formulas documented in WCAP-13587, Revision 1, with the methods and formulas cited in RG 1.161 and Appendix K to Section XI of the ASME Code. The formulas and methods in RG 1.161 and Appendix K to Section XI of the ASME Code are the same as those in WCAP-13587, except for the formulas for calculating the stress intensity factor from radial thermal gradients. The formulas for calculating the stress intensity factor from radial thermal gradients in WCAP-13587, Revision 1, result in higher stress intensity factors than the formulas in RG 1.161 and Appendix K to Section XI of the ASME Code. Since the formulas in WCAP-13587, Revision 1, result in conservative values of stress intensity factors, the results from the analysis in WCAP-13587, Revision 1, will satisfy RG 1.161 and Appendix K to Section XI of the ASME Code.

Since the limiting plates in the IP2 and IP3 RVs were projected to have greater Charpy USE values at the end of the period of extended operation than the minimum acceptable Charpy USE values in WCAP-13587, Revision 1, and the results from the analysis in WCAP-13587, Revision 1, will satisfy RG 1.161 and Appendix K to Section XI of the ASME Code, the applicant has demonstrated that the IP2 and IP3 RVs will have margins of safety against fracture equivalent to those required by Appendix G to Section XI of the ASME Code and will satisfy the requirements of Section IV.A.1.a of Appendix G to 10 CFR Part 50 through the end of the period of extended operation.

4.2.2.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of Charpy USE in LRA Sections A.2.2.1.3 and A.3.2.1.3, as amended by letter dated January 17, 2008. On the basis of its review of the UFSAR supplement, the staff has determined that the summary description of the applicant's actions to address Charpy USE is adequate.

4.2.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for Charpy USE, the analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.3 Pressure-Temperature Limits

4.2.3.1 Summary of Technical Information in the Application

LRA Section 4.2.3 summarizes the evaluation of P-T limits for the period of extended operation. Appendix G to 10 CFR Part 50 requires the applicant to maintain reactor pressure vessel operation within P-T limits established by calculations that utilize the materials and fluence data from the unit-specific Reactor Surveillance Capsule Program. Normally, the P-T limits calculated for several years into the future remain valid for an established period of time.

IP2 technical specifications provide P-T limits valid through 25 EFPYs, and IP3 technical specifications provide P-T limits valid through 34 EFPYs, both of which include the effects of the stretch power uprates that were approved on October 27, 2004 for IP2 (ADAMS Accession No. ML042960007), and on March 24, 2005 for IP3 (ADAMS Accession No. ML050600380). At present, plate B2803-3 (initial RT_{NDT} of 74 °F) restricts operation in the 150-250 °F range.

The applicant stated that the P-T limit curve updates will continue, as required by 10 CFR Part 50, Appendix G, or as operational needs dictate, to ensure that operational limits remain valid through the period of extended operation. Additional P-T limit analysis is not required at this time. Maintenance of the P-T limit curves in accordance with 10 CFR Part 50, Appendix G, ensures adequate management of the effects of aging on intended function(s) for the period of extended operation.

4.2.3.2 Staff Evaluation

The staff reviewed LRA Section 4.2.3 to verify that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. Since P-T limit curves are periodically updated in accordance with 10 CFR Part 50, Appendix G, and the license amendment process, compliance with 10 CFR Part 50 ensures that the P-T limit curves will be adequately managed for the period of extended operation. This is acceptable.

4.2.3.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of P-T limits in LRA Sections A.2.2.1.2 and A.3.2.1.2. On the basis of its review of the UFSAR supplement, the staff has determined that the summary description of the applicant's actions to address P-T limits is adequate.

4.2.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for P-T limits, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.4 Low-Temperature Overpressure Protection Power-Operated Relief Valve Setpoints

4.2.4.1 Summary of Technical Information in the Application

LRA Section 4.2.4 summarizes the evaluation of low-temperature overpressure protection (LTOP) power-operated relief valve (PORV) setpoints for the period of extended operation. For each revision of the P-T limit curves, the applicant must reevaluate the LTOP system to determine whether its functional requirements can be met; therefore, LTOP limits are part of the calculation of P-T curves.

4.2.4.2 Staff Evaluation

The staff reviewed LRA Section 4.2.4 to verify that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The LTOP PORV setpoints are determined whenever the applicant calculates P-T limit curves. Since P-T limit curves are periodically updated in accordance with 10 CFR Part 50, Appendix G, compliance with this rule ensures that the LTOP PORV setpoints will be adequately managed for the period of extended operation.

4.2.4.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of LTOP PORV setpoints in LRA Sections A.2.2.1.2 and A.3.2.1.2. On the basis of its review of the UFSAR supplement, the staff has determined that the summary description of the applicant's actions to address LTOP PORV setpoints is adequate.

4.2.4.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for LTOP PORV setpoints, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.5 Pressurized Thermal Shock

4.2.5.1 Summary of Technical Information in the Application

LRA Section 4.2.5 summarizes the evaluation of PTS for the period of extended operation. In accordance with 10 CFR 50.61(b)(1), applicants must assess reference temperature for pressurized thermal shock (RT_{PTS}) projected values whenever a significant change occurs in parameters (e.g., expiration date for facility operation) affecting RT_{PTS}. Specifically, 10 CFR 50.61(b)(2) establishes a screening criterion for RT_{PTS} of 270 °F for plates, forgings, and axial welds and a screening criterion of 300 °F for circumferential welds. RG 1.99, Revision 2, provides two methods (positions) for determining RT_{PTS}. Position 1 applies to material with no surveillance data available. Position 2 applies to material with surveillance data. Calculation of RT_{PTS} values use both Positions 1 and 2 follows RG 1.99, Revision 2, Sections 1.1 and 2.1, respectively, using the copper and nickel content of beltline materials and EOL best-estimate fluence projections.

The IP2 projected 48-EFPY peak beltline neutron fluence level of $1.906x10^{19}$ n/cm^2 at the clad-base metal interface applies to all beltline materials except the RV axial welds, where the expected peak fluence is $1.295x10^{19}$ n/cm^2. All projected RT_{PTS} values are within established screening criteria at 48 EFPYs.

The applicant stated that the IP3 projected 48-EFPY peak beltline neutron fluence level of $1.560x10^{19}$ n/cm^2 at the clad-base metal interface applies to all beltline materials. All projected RT_{PTS} values are within established screening criteria for 48 EFPYs with the exception of plate B2803-3, which exceeds the screening criterion of 270 °F by 9.9 °F. As required by 10 CFR 50.61(b)(4), the applicant will submit a plant-specific safety analysis for plate B2803-3 to the staff 3 years before the RT_{PTS} screening criterion is reached. Alternatively, IP3 may choose to implement the revised PTS rule (10 CFR 50.61a) which, if approved, will permit the application of RG 1.99, Revision 3, to plate B2803-3, with the expected result of an acceptable through-wall crack frequency at 48 EFPYs. Therefore, the aging effects of the RT_{PTS} TLAA will be adequately managed for the period of extended operation.

4.2.5.2 Staff Evaluation

The staff reviewed LRA Section 4.2.5 to verify that, pursuant to 10 CFR 54.21(c)(1)(ii), the analyses have been projected to the end of the period of extended operation and that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

As defined in 10 CFR 50.61(c)(1)(v), the RT_{PTS} value is the sum of the initial (unirradiated) reference temperature ($RT_{NDT(U)}$), the shift in reference temperature caused by neutron irradiation (ΔRT_{NDT}), and a margin term (M) to account for uncertainties. The methodology for determining the ΔRT_{NDT} and M values when no surveillance data exist is defined in 10 CFR 50.61(c)(1), while the methodology for determining the ΔRT_{NDT} and M values when surveillance data do exist is defined in 10 CFR 50.61(c)(2).

For IP2, LRA Table 4.2-3 indicates that the ΔRT_{NDT} value caused by irradiation for the intermediate shell axial welds and the lower shell axial welds in IP2 were determined using surveillance data reported in WCAP-15629, Revision 1. For IP3, LRA Table 4.2-4 indicates that the ΔRT_{NDT} caused by irradiation for the lower shell plate B2803-3 was determined using surveillance data reported by the applicant's response to Generic Letter (GL) 92-01, “Reactor Vessel Structural Integrity.” These surveillance data were reported in a September 4, 1998, letter from J. Knubel (New York Power Authority). The surveillance data from IP3 are also reported in WCAP-15629, Revision 1. The neutron fluence values for the IP3 surveillance capsule that are reported in WCAP-15629, Revision 1 and in the September 4, 1998, letter have different values. Therefore, by letter dated October 29, 2008, the staff asked the applicant to provide neutron fluence values derived using a methodology that adheres to the guidance in RG 1.190, and to provide the surveillance data analysis required by 10 CFR 50.61(c)(2)(i).

By letter dated November 28, 2007, the applicant responded to the staff's RAI and stated that for IP2, the revised fluences used from the H.B. Robinson plant that are consistent with the guidance of RG 1.190 have been calculated by Westinghouse. For IP3, the applicant stated that the neutron fluence values reported in LRA Table 4.2-4 were taken from a 2003 Westinghouse calculation supporting stretch power uprate. The neutron transport and dosimetry evaluation methods used to determine the fluence in the 2003 calculation followed the guidance of RG 1.190. During a telephone call held on December 3, 2007, the NRC staff requested that Entergy provide confirmation that the referenced source of the surveillance data satisfies RG 1.190, and that the surveillance data have been used in the Pressurized Thermal Shock and Charpy USE analyses. During a telephone call held on December 4, 2007, Entergy indicated that for Indian Point Unit 3, the current neutron flux and fluence values are contained in WCAP-16251, and that for IP2, WCAP-15805 contains the surveillance data for Capsule X for H. B. Robinson, and that it will revise the RAI response to reflect the source of the data.

By letter dated January 17, 2008, the applicant revised the PTS evaluation tables for the IP2 and IP3 RVs (LRA Tables 4.2-3 for IP2 and 4.2-4 for IP3).

LRA Table 4.2-3 indicates that the RT_{PTS} values for all the IP2 RV beltline materials are below the 10 CFR 50.61 PTS screening criteria at the end of the period of extended operation. The RT_{PTS} values for intermediate shell plates B2002-1, B2002-2, and B2002-3 are calculated using surveillance data from WCAP-15629, Revision 1, Table 4. The applicant determined the ΔRT_{NDT} and M values for these plates using the methodology in RG 1.99, Revision 2, Section 2.1, and 10 CFR 50.61(c)(2). The applicant determined the ΔRT_{NDT} and M values for IP2 plate B2003-1, plate B2003-2, and intermediate-to-lower shell circumferential weld 9-042 (Linde 1092, heat number 34B009) using the methodology in RG 1.99, Revision 2, Section 1.1, and 10 CFR 50.61(c)(1) since there are no surveillance data for these materials. The applicant calculated RT_{PTS} values for the intermediate shell and lower axial shell welds using surveillance data from WCAP-15805, Table D-1. This table contains data from the IP2, IP3, and H.B. Robinson surveillance welds. Combustion Engineering fabricated the IP2 intermediate shell axial welds, the IP2 lower axial shell welds, the IP2 surveillance weld, the IP3 surveillance weld, and the H.B. Robinson surveillance weld using Linde 1092 flux and heat number W5214 weld wire. The IP2, IP3, and H.B. Robinson surveillance welds were irradiated at different temperatures and have different amounts of copper and nickel.

After its review of the revised responses provided by the applicant in its letter dated January 17, 2008, the staff requested additional information regarding the methodology used in determining the impact of the different irradiation temperatures and different amounts of copper and nickel for the surveillance welds on the ΔRT_{NDT} and M values for the IP2 intermediate shell and lower axial shell welds. In a telephone conference call on May 7, 2008, the staff informed the applicant of the needed information. By letter dated June 11, 2008, the applicant identified the methodology used to determine the impact of the different irradiation temperatures and different amounts of copper and nickel for the surveillance welds on the ΔRT_{NDT} value for the IP2 intermediate shell and lower axial shell welds. The applicant determined the ΔRT_{NDT} value for the IP2 intermediate shell and lower axial shell welds by (1) using the ratio procedure described in Position 2.1 of RG 1.99, Revision 2, to normalize the surveillance weld chemical composition to the IP2 intermediate shell and lower axial shell welds chemical composition, and (2) using a correction factor of 1 ft-lb/°F of inlet coolant temperature. The IP2 RV operates with an inlet temperature of approximately 528 °F, the H.B. Robinson RV operates with an inlet temperature of approximately 547 °F, and the IP3 RV operates with an inlet temperature of approximately 540 °F. Therefore, the measured ΔRT_{NDT} values from the IP3 surveillance program were adjusted by adding 12 °F to each measured ΔRT_{NDT}, and the measured ΔRT_{NDT} values from the H.B. Robinson surveillance program were adjusted by adding 19 °F to each measured ΔRT_{NDT} before applying the ratio procedure. This method of determining the ΔRT_{NDT} is acceptable; the staff has previously endorsed its use, at the RPV Integrity Workshop (February 12, 1998), for normalizing surveillance data from other RVs to the chemical composition and inlet temperature of the RV being evaluated. Additionally, the staff has approved the use of the methodology on plant-specific bases.

As stated in its June 11, 2008 letter, the applicant calculated the M value for the IP2 intermediate shell and lower shell axial welds using Position 2.1 of RG 1.99, Revision 2. The staff confirmed that the surveillance data satisfy the credibility criteria in RG 1.99, Revision 2. Therefore, the M value should be determined using Position 2.1 of RG 1.99, Revision 2.

Based on the above discussion, the staff finds the applicant's responses to the RAIs acceptable. The staff finds that the IP2 PTS analyses have been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

LRA Table 4.2-4 indicates that the RT_{PTS} values for all IP3 beltline materials, except for plate B2803-3, are projected to be below the PTS screening criteria at the end of the period of extended operation, pursuant to 10 CFR 50.61. The applicant determined the ΔRT_{NDT} and M values for all beltline materials, except for plate B2803-3, using the methodology in RG 1.99, Revision 2, Section 1.1, and 10 CFR 50.61(c)(1), since there are no surveillance data for these materials. The RT_{PTS} value for plate B2803-3 was calculated using surveillance data from WCAP-16251-NP, Table 5-10. The ΔRT_{NDT} and M values for plate B2803-3 were determined using the methodology in RG 1.99, Revision 2, Section 2.1, and 10 CFR 50.61(c)(2). The RT_{PTS} value at the end of the period of extended operation for plate B2803-3 was 279.5 °F. The staff confirmed that the RT_{PTS} value for plate B2803-3 at the end of the period of extended operation was calculated in accordance with RG 1.99, Revision 2 and 10 CFR 50.61.

As indicated in 10 CFR 50.61(b)(4), each pressurized-water nuclear power reactor for which the analysis required by the PTS rule indicates that, if there is no reasonably practicable flux reduction program to prevent the RT_{PTS} value from exceeding the PTS screening criteria based on the neutron fluence at the expiration date of the operating license, the licensee shall submit a safety analysis to determine what, if any, modifications to equipment, systems, and operation are necessary to prevent potential failure of the RV as a result of postulated PTS events, if continued operation beyond the screening criterion is allowed. The analysis must be submitted at least 3 years before the RT_{PTS} value is projected to exceed the PTS screening criteria. LRA Section 4.2.5 indicates that the RT_{PTS} value for plate B2803-3 in IP3 will exceed the PTS screening criterion. Therefore, by letter dated October 29, 2007, the staff asked the applicant to identify when the RT_{PTS} value for plate B2803-3 in IP3 is projected to exceed the PTS screening criterion.

In its November 28, 2007 response to RAI 4.2.5-2, the applicant indicated the following:

> Plate B2803-3 will reach the screening criterion at approximately 37 EFPY. Using a plant capacity factor of 0.97 after 2007, IP3 will achieve 37 EFPY approximately 9 years after entering the period of extended operation.
>
> With regard to flux reduction, IP3 implemented a low-low leakage loading plan in 1986 by placing fresh fuel in the interior of the core. Flux suppressors consisting of Pyrex glass were added to eight corner locations of the core in 1995. Since 1999, the suppressor material has been unclad hafnium. These flux reduction methods have been successful. However, these methods alone will not prevent plate B2803-3 from reaching the screening criterion during the period of extended operation.
>
> Commitment No. 32 states,
>
> As required by 10 CFR 50.61(b)(4), IP3 will submit a plant-specific safety analysis for plate B2803-3 to the NRC three years prior to reaching the RT_{PTS} screening criterion. Alternatively, the site may choose to implement the revised PTS (10 CFR 50.61) rule when approved, which would permit use of Regulatory Guide 1.99, Revision 3.
>
> Application of Regulatory Guide 1.99, Revision 3 to plate B2803-3 is expected to result in an acceptable RT_{PTS} value at 48 EFPY for IP3.

As worded in the commitment, when referring to the revised PTS rule, the applicant erroneously cites the existing PTS rule. In addition, the applicant referred to the use of RG 1.99, Revision 3, which is currently not cited by the proposed revised PTS rule. By letter dated August 14, 2008, the applicant amended LRA Sections 4.2.5 and A.3.2.1.4 to remove the reference to RG 1.99, Revision 3.

Based on the above discussion, the staff finds the applicant's response to the RAI and commitment for IP3 acceptable. The applicant's commitment will ensure that the PTS-related aging effects for IP3 will be managed during the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(iii).

In a letter dated September 24, 2008, the applicant stated that the RT_{PTS} values for the nozzle shell plates, nozzle-to-shell longitudinal welds, and the nozzle-to-intermediate shell circumferential weld in the IP2 and IP3 vessels would be less than 100° F at the end of the period of extended operation. The applicant further stated that these values were determined using the methodology documented in RG 1.99, Revision 2 and in 10 CFR 50.61. Since the RT_{PTS} values are less than the screening criterion in 10 CFR 50.61(b)(2), the staff finds that these components meet the requirements of 10 CFR 50.61.

4.2.5.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of PTS in LRA Sections A.2.2.1.4, and A.3.2.1.4, as amended. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address PTS is adequate.

4.2.5.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for IP2, the PTS analyses have been projected to the end of the period of extended operation. The applicant has also demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for IP3, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3 Metal Fatigue

The applicant states in LRA Section 4.3 that fatigue analyses are potential TLAAs for Class 1 and selected non-Class 1 mechanical components. Fatigue is age-related degradation caused by cyclic stressing of a component by either mechanical or thermal stresses. Fatigue analyses are TLAAs if they meet the six defined elements pursuant to 10 CFR 54.3(a). If the analyses are based on a number of cycles estimated for the current license term, they may meet the 10 CFR 54.3(a)(3) criterion of “defined by the current operating term.” The applicant evaluates the TLAA in accordance with 10 CFR 54.21(c)(1) to determine which of the following conditions are demonstrated:

(i) The analyses remain valid for the period of extended operation;

(ii) The analyses have been projected to the end of the period of extended operation; or

(iii) The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The applicant also states that the aging management reviews (AMRs) of the integrated plant assessment (summarized in SER Section 3) identified all components as susceptible to fatigue damage. If a component has a fatigue TLAA that remains valid (10 CFR 54.21(c)(1)(i)) or is projected to cover the period of extended operation (10 CFR 54.21(c)(1)(ii)), cracking from fatigue is not an aging effect requiring management. If the TLAA does not remain valid for the period of extended operation, cracking from fatigue is an aging effect requiring management for the analyzed component. Cracking from fatigue can be managed by various plant programs in accordance with 10 CFR 54.21(c)(1)(iii).

The applicant states that fracture mechanics analyses of flaws detected during inservice inspection (ISI) may be TLAAs for those analyses based on time-limited assumptions defined by the current operating term. When a flaw is detected during ISI, the component may be replaced, repaired, or evaluated for continued service in accordance with ASME Code, Section XI. These evaluations may show that the component is acceptable to the end of the period of extended operation with projected inservice flaw growth typically predicted based on design thermal and mechanical loading cycles.

4.3.1 Class 1 Fatigue

The applicant states in LRA Section 4.3.1 that components that are designed in accordance with ASME Code, Section III, have fatigue analyses. Current design-basis fatigue evaluations calculate cumulative usage factors (CUFs) based on design transient cycles for components or subcomponents. The current design-basis fatigue evaluations do not consider the effects of reactor water environment on fatigue life. This practice is consistent with SECY-95-245, "Completion of the Fatigue Action Plan," dated September 25, 1995, which indicates that no immediate staff or licensee action is necessary on the environmentally assisted fatigue issue before the period of extended operation for license renewal.

The applicant states that the number of cycles accrued to date has been projected to determine the numbers of cycles expected at the end of 60 years of operation. With limited exceptions (discussed below), the projected numbers of cycles for 60 years of operation do not exceed the analyzed numbers of cycles.

The Fatigue Monitoring Program (FMP) tracks and evaluates design transients and requires corrective actions if the number of analyzed transients are approached, to keep the number of transient cycles experienced by the plant within the analyzed numbers of cycles, thus keeping the component CUFs below the values calculated in the design-basis fatigue evaluations. Appendix B to the LRA provides further details on the Fatigue Monitoring Program.

IP2 cycle counts are for normal conditions, test conditions, abnormal (upset) conditions, pressurizer spray actuations, and other events. A rate per day, calculated for each event and multiplied by the days remaining to the end of the period of extended operation, projects the cycles. Rates for most transients are based on the cycles accrued to date and the time from initial operation. Some transients (e.g., reactor trips) were projected based on the IP2 1999 to 2005 operating history, because plant operating practices have changed and some of the transients occur more or less often now than early in plant life.

The applicant stated that some transients, such as reactor trips, were projected based on more recent operating history, i.e., 1999 to 2005, because its plant operating practices have changed and some of the transients occur more or less often now than they did early in plant life. The applicant further stated that there were substantially more reactor trips in the early years of operation at IP2, and that the rate of reactor trips experienced in the last six years is more representative of the rate of trips expected through the remainder of plant life. The applicant identified the following exceptions to its use of the number of cycles accrued to date to make its 60-year projections for IP2:

> The only normal condition projecting above the analyzed number of cycles is steady state fluctuations. The projection is $1.5x10^6$ while the analyzed number is $1x10^6$. However, the value shown in Table 4.3-1 is not based on actual cycles. The value shown in Table 4.3-1 for cycles as of 10/31/1999 is a calculated value based on the assumption that the transients occur at a constant rate that results in a number of transients over 40 years of operation equal to the analyzed number of transients. Hence the projection to 60 years based on this calculated value is 1.5 times the analyzed number of transients. In accordance with the Fatigue Monitoring Program, prior to the period of extended operation, corrective actions will be taken to confirm that monitoring is not required or to establish appropriate monitoring.

Feedwater cycling, a replacement steam generator design transient limited to 18,300 cycles, does not appear on Table 4.3-1. The value of 18,300 is the projected value for 40 years of steam generator operation. Since the IP2 replacement steam generators will not be in service for 40 years at the end of the period of extended operation, feedwater cycling is not expected to exceed the analyzed number of cycles.

The only abnormal condition projected to exceed its monitored limit is loss of power. Enhancements related to “loss of power” cycling may be found in the Fatigue Monitoring Program, Section B.1.12.

Several of the “Other Events” will exceed their analyzed numbers prior to the end of the period of extended operation. These transients apply to the charging system piping, which is evaluated and described in SER Section 4.3.3.

As indicated, for certain events that affect fatigue usage, linear projections of the actual data to the end of the period of extended operation exceed the analyzed numbers of design-basis transients; however, there is implicit margin in the conservative CUF estimates. When additional fatigue analysis is required to take advantage of the implicit margin, the Fatigue Monitoring Program will take actions before the analyzed numbers of transients are exceeded. IP2 will continue to monitor analyzed cycles under the Fatigue Monitoring Program. Enhancements to the Fatigue Monitoring Program described in LRA Appendix B address the 60-year projections.

For IP3, the applicant tracks transients of the RV, safety injection actuations, and residual heat removal (RHR) cycles. A rate per day calculated for each transient, multiplied by the days remaining to 60 years, projects the number of future cycles. Rates are based on cycles accrued to date and time from initial operation.

The numbers of plant heatups and cooldowns are from the IP3 shutdown history and shutdown summary, which show the shutdown count through 1995. IP3 used the rate from 1973 to 1995 to project shutdowns and startups, and this projection should be conservative, as improved operations have resulted in less frequent shutdowns and startups in recent years.

The IP3 60-year projections showed that the number of transients will not exceed the number of analyzed cycles before the end of the period of extended operation.

The applicant stated that the Fatigue Monitoring Program will ensure that the analyzed numbers of transients are not exceeded during the period of extended operation. Enhancements to the Fatigue Monitoring Program described in LRA Appendix B will add transients to the IP3 list of those monitored as is the case for the IP2 list.

<u>Staff Evaluation</u>

The staff reviewed the applicant’s estimate of the number of cycles for transients for a 60-year plant operation for IP2 and IP3.

For IP2, the applicant based its projections for the period of extended operation on operating history, from 1999 through 2005 for some transients. The applicant’s use of more recent data to account for changes in plant operating practices is reasonable because it provides a realistic estimate for when the cycles (after 60 years of operation) might approach the number of analyzed cycles. The staff agrees with the applicant's projection. To provide additional assurance, the applicant will continue to monitor the transients under the Fatigue Monitoring Program and take corrective action before the number of analyzed cycles is reached.

For IP3, the applicant based its projections for the period of extended operation on operating history, from 1975 through 1995. Although this approach differs from the approach used for IP2, it yields a conservative estimate for when the cycles (after 60 years of operation) might approach the number of analyzed cycles. As stated above, to provide additional assurance, the applicant will continue to monitor the transients under the Fatigue Monitoring Program and take corrective action before the number of analyzed cycles is reached.

Based on the above, the staff finds that the approaches used by the applicant to calculate the 60-year projections for each unit are reasonable.

In its review, the staff noted that the applicant used data from 1973 to 1995 to project the number of plant heatups and cooldowns from 1995 to March 31, 2006 (current cycles), rather than use actual data. As stated above, the applicant will track the number of transients under the Fatigue Monitoring Program. However, without the actual number of heatups and cooldowns from 1995 to March 31, 2006, the applicant may not be able to accurately predict when the number of analyzed cycles might be exceeded. The staff notes that changes in operating practices such as refueling (12-month refueling cycle vs. 24-month refueling cycle) would decrease the number of heatups and cooldowns experienced post 1995, which should yield a more conservative projection. Nonetheless, the applicant should have the actual data for the plant startups and shutdowns during this period of time. Therefore, the staff believes that the use of actual plant operating experience in lieu of a projection for the current number of cycles is appropriate. This was identified as Open Item 4.3-1.

By letter dated January 27, 2009, the applicant stated that the actual number of cycles for IP3 plant heatups and cooldowns was determined to be 55 cycles through March 31, 2006. The applicant further stated that based on this value, the 60-year projection approximates 109 plant heatups and 109 plant cooldowns. This information was previously provided to the staff in response to Audit Item 14, by letter dated March 24, 2008. It is response, the applicant stated that at the time the LRA was prepared, the cycle count for plant heatups and cooldowns had only accounted the raw data through December 31, 2005, because it was readily available at the time; therefore, this information was used in the LRA. On the basis of its review, the staff finds the applicant's response acceptable because the applicant determined the accrued cycles of plant heatups and cooldowns based on actual plant data and operating experience through March 31, 2006. Therefore, Open Item 4.3-1 is closed.

4.3.1.1 Reactor Vessel

4.3.1.1.1 Summary of Technical Information in the Application

LRA Section 4.3.1.1 describes the evaluation performed for the RV. The fatigue analyses for the RV were performed in accordance with ASME Code, Section III, 1965 edition, 1966 and 1967 addenda. Tables 4.3-3 and 4.3-4 present current CUF values for the RV for IP2 and IP3, respectively. The applicant stated that these TLAA results are based on those design transients listed in LRA Tables 4.3-1 for IP2 and 4.3-2 for IP3. The applicant stated that since the projected numbers of transient cycles remain within analyzed values, the TLAAs for the RV fatigue analyses will remain valid for the period of extended operation.

4.3.1.1.2 Staff Evaluation

The staff reviewed LRA Section 4.3.1.1 to verify that, pursuant to 10 CFR 54.21(c)(1)(i), the analyses remain valid for the period of extended operation or that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

During an onsite audit, the staff reviewed LRA Tables 4.3-1 and 4.3-2, which list the design transient cycles and transient cycles projected for 60 years of plant operation. The staff noted that LRA Table 4.3-1 includes IP2 design transients whose 60-year projections exceed design cycles. However, LRA Section 4.3.1.1 states, “the projected numbers of transient cycles used for reactor vessel fatigue analyses remain within analyzed values,” and cites the requirements of 10 CFR 54.21(c)(1)(i) for its RV TLAA. The staff asked the applicant to justify this conclusion (Audit Item 11).

In its response, dated March 24, 2008, the applicant stated the following:

> Since the Fatigue Monitoring Program assures that the analyzed numbers of cycles are not exceeded, IPEC will clarify LRA Section 4.3.1.1 to show that the effects of fatigue will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii). Section 4.3.1.1 will be revised as follows:
>
> The reactor pressure vessel (and appurtenances) fatigue analyses were performed in accordance with the requirements of ASME Boiler and Pressure Vessel Code, Section III, 1965 Edition, 1966 and 1967 addenda. (A complete listing of applicable codes is given in Tables 4.1-9 of the IP2 and IP3 UFSARs). The existing fatigue analyses of the reactor vessel are considered TLAA because they are based on numbers of cycles expected in 40 years of operation. The CUFs for the reactor pressure vessel are given in Table 4.3-3 for IP2 and Table 4.3-4 for IP3. Design cyclic loadings and thermal conditions for the reactor pressure vessel were originally defined in the design specifications and analyzed in the original vessel stress reports. These analyses have been occasionally revised, most recently for the extended power uprate. These latest analyses are reflected in the current UFSAR tables. As described in Section 4.3.1, the projected numbers of transient cycles used for reactor vessel fatigue analyses remain within analyzed values. The effects of fatigue on the reactor vessel will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii) for both IP2 and IP3.

The staff finds the applicant’s response acceptable because the applicant will manage the effects of fatigue on the RV for both IP2 and IP3 by the Fatigue Monitoring Program, in accordance with 10 CFR 54.21(c)(1)(iii), rather than relying on an analysis performed in accordance with 10 CFR 54.21(c)(1)(i). SER Section 3.0.3.2.6 documents the staff’s evaluation of the applicant’s Fatigue Monitoring Program. The staff concludes that the applicant’s aging management is consistent with the recommendations of the SRP-LR, and satisfies the applicable regulatory requirements.

4.3.1.1.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of the RV in LRA Sections A.2.2.2.1 and A.3.2.2.1. In response to the staff's question as described above, the applicant revised LRA Sections A.2.2.2.1 and A.3.2.2.1 to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). The staff verified that the applicant's amendment, dated March 24, 2008, included the changes to LRA Sections A.2.2.2.1 and A.3.2.2.1.

On the basis of its review of the UFSAR supplement, the staff finds that the summary description of the applicant's TLAA evaluation of the RV is adequate.

4.3.1.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the RV, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.1.2 Reactor Vessel Internals

4.3.1.2.1 Summary of Technical Information in the Application

LRA Section 4.3.1.2 describes the evaluation performed for the reactor vessel internals. The reactor vessel internals were designed to meet the intent of ASME Code, Section III, Subsection NG. LRA Tables 4.3-5 and 4.3-6 present CUF values for the reactor vessel internals for IP2 and IP3, respectively. The applicant stated that the CUFs, based on the same transients as those for the reactor vessel, will not be exceeded in 60 years; therefore, these TLAAs remain valid for the period of extended operation.

4.3.1.2.2 Staff Evaluation

The staff reviewed LRA Section 4.3.1.2 to verify that, pursuant to 10 CFR 54.21(c)(1)(i), the analyses remain valid for the period of extended operation or that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

During an onsite audit, the staff reviewed LRA Tables 4.3-5 and 4.3-6, which list the CUF values for various reactor vessel internals for IP2 and IP3, respectively. The staff noted that these CUFs were derived from the results of Indian Point stretch power uprate nuclear steam supply engineering reports (WCAP-16156-P for IP2 and WCAP-16211-P for IP3). The staff asked the applicant to explain why the CUF value (0.173) for the IP2 upper support plate differs from the CUF value (0.81) for IP3 (Audit Item 8). In its response, dated March 24, 2008, the applicant offered the following explanation:

> The IP3 analysis was a later analysis performed for the IP3 power uprate that used a different cross section of the upper support plate than the older IP2 analysis. The IP3 analysis resulted in a higher CUF of 0.81. The result of the IP3 analysis is also applicable to IP2. The LRA will be revised to change the CUF

value for the IP2 upper support plate in Table 4.3-5 to 0.81.

The staff finds the applicant's response acceptable, because the later analysis was performed by the applicant using a finer cross-section model, which was a more accurate model.

In LRA Section 4.3.1.2, the applicant stated that the calculated CUFs are based on number of cycles expected during 40 years of operation and that these values will not be exceeded in 60 years; therefore, the TLAAs remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). During the audit, the staff reviewed LRA Tables 4.3-1 and 4.3-2 which list the design transient cycles and transient cycles projected for 60 years of plant operation. The staff noted that LRA Table 4.3-1 includes IP2 design transients whose 60-year projections exceed design cycles. During an onsite audit, the staff asked the applicant to justify its conclusion that TLAAs remain valid for the period of extended operation (Audit Item 12).

In its response, dated March 24, 2008, the applicant stated that the Fatigue Monitoring Program will be relied on to ensure that the analyzed numbers of transients are not exceeded. Additionally, the applicant stated that it will clarify LRA Section 4.3.1.2 to state that the effects of fatigue will be managed by the Fatigue Monitoring Program, in accordance with 10 CFR 54.21(c)(1)(iii). In the same letter, the applicant amended LRA Section 4.3.1.2 to state that "[t]he effects of fatigue on the reactor vessel internals will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii) for both IP2 and IP3."

The staff finds the applicant's response acceptable, because the applicant will manage the effects of fatigue on the RV by the Fatigue Monitoring Program for both IP2 and IP3, in accordance with 10 CFR 54.21(c)(1)(iii), rather than relying on an analysis performed in accordance with 10 CFR 54.21(c)(1)(i). SER Section 3.0.3.2.6 documents the staff's evaluation of the applicant's Fatigue Monitoring Program. The staff concludes that the applicant's aging management is consistent with the recommendations of the SRP-LR and satisfies the applicable regulatory requirements.

4.3.1.2.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of the RV in LRA Sections A.2.2.2.1 and A.3.2.2.1. In response to the staff's question, as described above, the applicant revised LRA Sections A.2.2.2.1 and A.3.2.2.1 to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). The staff verified that the applicant's amendment, dated March 24, 2008, included the changes to LRA Sections A.2.2.2.1 and A.3.2.2.1.

On the basis of its review of the UFSAR supplement, the staff finds that the summary description of the applicant's TLAA evaluation of the reactor vessel internals is adequate.

4.3.1.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the reactor vessel internals, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.1.3 Pressurizer

4.3.1.3.1 Summary of Technical Information in the Application

LRA Section 4.3.1.3 describes the evaluation performed for the pressurizer. The original pressurizer stress report met the requirements of ASME Code, Section N-415.1, "Vessels Not Requiring Analysis for Cyclic Operation." LRA Tables 4.3-7 and 4.3-8 present CUF values for the pressurizer for IP2 and IP3, respectively.

The original design-basis calculations for the pressurizer did not consider the impact of pressurizer insurge/outsurge transients. The IP2 CUF of record for the pressurizer surge nozzle remains the original design stress report number of 0.264. For IP3, the applicant re-evaluated the pressurizer surge line nozzle CUF to consider insurge/outsurge during the 200 design heatups and cooldowns and revised it to 0.9612. The applicant stated that, because the cycles on which these analyses are based will not be exceeded during the period of extended operation, these TLAAs remain valid for the period of extended operation. The applicant also stated that these surge nozzles, which are required to consider the environmental effects, will be reanalyzed for license renewal.

4.3.1.3.2 Staff Evaluation

The staff reviewed LRA Section 4.3.1.3 to verify that, pursuant to 10 CFR 54.21(c)(1)(i), the analyses remain valid for the period of extended operation or that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

During an onsite audit, the staff reviewed LRA Tables 4.3-1 and 4.3-2, which list the design transient cycles and transient cycles projected for 60 years of plant operation. The staff noted that LRA Table 4.3-1 includes IP2 design transients whose 60-year projections exceed design cycles. However, LRA Section 4.3.1.1 states, "the projected numbers of transient cycles used for reactor vessel fatigue analyses remain within analyzed values," and cites the requirements of 10 CFR 54.21(c)(1)(i) for its RV TLAA. The staff asked the applicant to justify this conclusion (Audit Item 12).

In its response, dated March 24, 2008, the applicant stated the following:

> These TLAA remain valid as stated as long as the analyzed values for the relevant transients are not exceeded. Since the Fatigue Monitoring Program (FMP) is relied on to assure that the numbers of transients do not exceed the analyzed values, IPEC will credit the FMP for managing the effects of aging for the period of extended operation.
>
> LRA Sections 4.3.1.2 thru 4.3.1.8 and LRA Table 4.1-2 will be revised to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

In the same letter, the applicant amended its LRA according to the above response. The staff reviewed the change and noted that the correct regulation is reflected in the LRA. On this basis, the staff finds the applicant's response acceptable.

During an onsite audit, the staff reviewed LRA Section 4.3.1.1 and noted that the applicant stated that the impact of steady-state fluctuations on pressurizer fatigue determination is "not significant." The staff asked the applicant to explain the technical basis for its statement that the steady-state oscillations do not have a significant impact on fatigue (Audit Item 7).

In its response, dated March 24, 2008, the applicant stated the following:

> ASME Section III, Article 415.1(d) states, "a temperature fluctuation shall be considered to be significant if its total algebraic range exceeds the quantity S/(2*Me*Cte) where S is the value of Sa obtained from the applicable design curve for 1E6 cycles." From Figure N-415(A) of ASME Section III, Sa for 1 E6 cycles (carbon steel) is 13000 psi. From Table N-426, the coefficient of thermal expansion, Cte, for carbon steel at 500 °F is 7.94 E-6 in/in/°F. From Figure N-427 of ASME Section III the modulus of elasticity, Me, for carbon steel of less than 0.3 percent carbon at 500 °F is 26.4 E6 psi/in/in. This results in a significant temperature change of 13000/(2 * 7.94 E-6 * 26.4 E6) for a value of 31 °F. As the steady state oscillations have an algebraic range of ±3 °F maximum, they are not significant as defined by the ASME Code.

The staff reviewed the applicant's response and noted that ±3 °F is not significant according to the ASME Code. In addition, the staff performed an independent calculation of the temperature fluctuation according to ASME Code, NB- 3222.4, to verify the applicant's calculation. On this basis, the staff finds the applicant's response acceptable.

The applicant listed CUFs for various components of the pressurizer in LRA Tables 4.3-7 and 4.3-8. These IP2 and IP3 CUF values were in general agreement with the exception of the surge nozzle. The listed CUF for the IP2 surge nozzle is 0.264, while the CUF for the IP3 surge nozzle is 0.9612. The applicant explained that the discrepancy is because LRA Table 4.3-7 listed the CUFs of record for the IP2 pressurizer without consideration of the insurge/outsurge transients.

The applicant stated in LRA Section 4.3.1.8 that it made changes to operating procedures in response to NRC Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification," dated December 20, 1988. During the onsite audit, the staff asked the applicant whether it factored the mitigation strategy into the determination of the IP3 pressurizer surge nozzle CUF of 0.9612 and how it captured the fatigue usage before the use of the modified procedures in the fatigue evaluation (Audit Item 15).

In its response, dated March 24, 2008, the applicant stated the following:

> The mitigation strategy was not factored into the determination of the IP3 pressurizer surge line nozzle CUF. The calculation that determined the CUF of 0.9612 assumed the operating conditions that existed prior to implementation of the modified operating procedures. The operating conditions before implementation of modified procedures were conservatively applied to determine both the contribution to the CUF from past operation and the contribution to the CUF due to projected future operation. The delta-T (temperature)s used in the analysis were developed from plant operating records from a number of plants. This historical delta-T information was used to represent the prior operating history of the Indian Point units, and to calculate fatigue usage due to future

> operation. The IP3 surge nozzle CUF of record was calculated in IP3-CALC-RCS-00568, Revision 0, issued in 1993. Prior to this calculation, the CUF of record was the 0.259 calculated in the original stress report for the pressurizer. The original stress report had no analysis of insurge/outsurge.

The staff finds the applicant's response acceptable because (1) the applicant conservatively used the delta-T, which is based on data before implementation of the modified operating procedures; and (2) the CUF for the pressurizer surge line nozzles will be recalculated by including the environmentally assisted fatigue effects, as indicated in SER Section 4.3.3.2.

During the audit, the staff also asked the applicant to discuss the modified operating procedures used to mitigate the pressurizer insurge/outsurge transients. Further, the staff asked the applicant to provide actual plant data before and after plant procedures were modified to support that these changes reduced the occurrence and severity of these transients (Audit Item 15).

In its response, dated March 24, 2008, the applicant stated the following:

> IP2 and IP3 instituted operating changes consistent with the generic Westinghouse program to address surge line thermal cycling. There were two main changes: 1) A continuous (reduced flow) pressurizer spray was established. This minimized the temperature differential between the RCS, the pressurizer, and the surge line; thereby reducing the thermal stresses associated with an insurge. 2) Startup procedures were changed to eliminate drawing and then collapsing a pressurizer bubble to run reactor coolant pumps to sweep air out of the RCS/RPV. The collapsing of this bubble early in the startup procedure had resulted in significant insurges that have now been eliminated.
>
> Plant procedures that were changed include 2-POP-1.1, "Plant Heatup from Cold Shutdown Condition"; 2-POP-3.3, "Plant Cooldown, Mode3 to Mode5"; 3-POP1.1, "Plant Heatup from Cold Shutdown Condition"; 3-POP-3.3, "Plant Cooldown—Hot to Cold Shutdown." Results of the changes are discussed in Interoffice Correspondence IP-DEM-01-008MC, "IP3 Pressurizer Surge Line Stratification—WR-96-6280-02." The letter notes that after procedure changes, the maximum difference between the pressurizer and surge line and the RCS was 227 °F, well within the 320 °F limit. The letter concludes that the procedure changes effectively lowered the delta °F and eliminated the insurge/outsurge transients.

As documented in the Audit Report, the staff reviewed portions of WCAP-12639 and the procedures referenced in the applicant's response. In addition, the staff reviewed the interoffice correspondence which documents the effectiveness of the applicant's procedure changes. The staff verified that the delta-Ts between the pressurizer and surge line and the reactor coolant system (RCS) were reduced after implementing the modified operating procedures. On the basis of these reviews, the staff finds the applicant's response acceptable.

During the audit, the staff reviewed LRA Section 4.3.1.3 and noted several areas that required clarification. The staff asked the applicant to clarify a typographical error on page 4.3-12 of the LRA regarding the number of steady-state oscillations that were analyzed in the stress report. In addition, the staff asked the applicant to clarify page 4.3-13 of the LRA by verifying that the original stress report only analyzed the surge and spray nozzles (Audit Item 9).

In its response, dated March 24, 2008, the applicant stated the following:

> LRA Section 4.3.1.3 contains a typographical error. It should have stated 10 to the sixth power or 1E6 oscillations rather than 106 oscillations. WNET-108 clearly uses 1 E6 steady state oscillations.
>
> The second sentence on page 4.3-13 is correct as written. However, this sentence can be misleading and Entergy will reword it as follows: "While the original stress report did not analyze the pressurizer shell, it did analyze the surge nozzle and spray nozzle. The resulting CUFs are not the CUFs of record as both the surge and spray nozzles were subsequently reevaluated for the stretch power uprates. The usage factors of record are given in Tables 4.3-7 and 4.3-8.

The staff reviewed the applicant's response as well as the basis document for LRA Section 4.3.1.3. In the same letter, the applicant amended the LRA according to the response above. The staff noted that the applicant's response is editorial and clarifying in nature; therefore, it does not change the technical content of LRA Section 4.3.1.3. On this basis, the staff finds the response acceptable.

In LRA Section 4.3.1.3, the applicant stated that the pressurizer fatigue analyses remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). Since the results reflected in LRA Table 4.3-7 do not consider insurge/outsurge, the staff asked the applicant to justify its conclusion that TLAAs remain valid for the period of extended operation (Audit Item 13).

In its response, dated March 24, 2008, the applicant stated the following:

> Both IP2 and IP3 surge nozzles must be re-evaluated for environmentally assisted fatigue and IPEC has committed to that reanalysis prior to the period of extended operation. That reanalysis will include not only environmental factors, but also the effects of insurge/outsurge for both units.
>
> LRA Section 4.3.1.3 will be revised to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

The staff finds the applicant's response acceptable because the applicant will manage the effects of fatigue on the RV by the Fatigue Monitoring Program for both IP2 and IP3, in accordance with 10 CFR 54.21(c)(1)(iii), rather than relying on an analysis performed in accordance with 10 CFR 54.21(c)(1)(i). SER Section 3.0.3.2.6 documents the staff's evaluation of the applicant's Fatigue Monitoring Program. The staff concludes that the applicant's aging management is consistent with the recommendations of the SRP-LR and satisfies the applicable regulatory requirements.

4.3.1.3.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of the pressurizer in LRA Sections A.2.2.2.1 and A.3.2.2.1. In response to the staff's question as described above, the applicant revised LRA Sections A.2.2.2.1 and A.3.2.2.1 to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). The staff verified that the applicant's amendment, dated March 24, 2008, included the changes to LRA Sections A.2.2.2.1 and A.3.2.2.1.

On the basis of its review of the UFSAR supplement, the staff finds that the summary description of the applicant's TLAA evaluation of the pressurizer is adequate.

4.3.1.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the pressurizer, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.1.4 Steam Generators

4.3.1.4.1 Summary of Technical Information in the Application

LRA Section 4.3.1.4 describes the evaluation performed for the steam generators. Both IP2 and IP3 have had their steam generators replaced, IP2 in January 2001 and IP3 in June 1989. The replacement steam generators were analyzed for fatigue in their component stress reports and were then reevaluated for fatigue because of the power increase. LRA Tables 4.3-9 and 4.3-10 present CUF values for the steam generators for IP2 and IP3, respectively. The applicant stated that none of the design transients for steam generator fatigue analysis are projected to exceed their analyzed numbers during the period of extended operation. Therefore, the applicant stated that these usage factor calculations based on the design transients will remain valid for the period of extended operation.

4.3.1.4.2 Staff Evaluation

The staff reviewed LRA Section 4.3.1.4 to verify that, pursuant to 10 CFR 54.21(c)(1)(i), the analyses remain valid for the period of extended operation or that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The applicant listed the CUF values for various steam generator components in LRA Tables 4.3-9 and 4.3-10 for IP2 and IP3, respectively. As documented in the Audit and Review Report, the staff noted that these CUFs were derived from the results of Indian Point stretch power uprate nuclear steam supply engineering reports. The applicant stated that these usage factor calculations are based on the design discussed in LRA Section 4.3.1 and determined that the analyses remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). During the onsite audit, the staff noted that LRA Table 4.3-1 includes IP2 design transients whose 60-year projections exceed design cycles. The staff asked the applicant to justify its conclusion that TLAAs remain valid for the period of extended operation (Audit Item 12).

In its response, dated March 24, 2008, the applicant stated that these TLAAs remain valid, as stated, as long as the analyzed values for the relevant transients are not exceeded. Since the Fatigue Monitoring Program is relied on to ensure that the numbers of transients do not exceed the analyzed values, IP2 and IP3 will credit the Fatigue Monitoring Program for managing the effects of aging for the period of extended operation. The applicant also stated that it will revise LRA Section 4.3.1.4 to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). In the same letter, the applicant revised the LRA. The staff verified that the applicant's amendment, dated March 24, 2008, included the changes to LRA Section 4.3.1.4.

The staff finds the applicant's response acceptable because the applicant will manage the effects of fatigue for the steam generator components by the Fatigue Monitoring Program for both IP2 and IP3, in accordance with 10 CFR 54.21(c)(1)(iii), rather than relying on an analysis performed in accordance with 10 CFR 54.21(c)(1)(i). SER Section 3.0.3.2.6 documents the staff's evaluation of the applicant's Fatigue Monitoring Program. The staff concludes that the applicant's aging management is consistent with the recommendations of the SRP-LR and satisfies the applicable regulatory requirements.

4.3.1.4.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of steam generators in LRA Sections A.2.2.2.1 and A.3.2.2.1. In response to the staff's question as described above, the applicant revised LRA Sections A.2.2.2.1 and A.3.2.2.1 to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). The staff verified that the applicant's amendment, dated March 24, 2008, included the changes to LRA Sections A.2.2.2.1 and A.3.2.2.1.

On the basis of its review of the UFSAR supplement, the staff finds that the summary description of the applicant's TLAA evaluation of the steam generators is adequate.

4.3.1.4.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for steam generators, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.1.5 Reactor Coolant Pump Fatigue Analysis

4.3.1.5.1 Summary of Technical Information in the Application

LRA Section 4.3.1.5 describes the evaluation performed for the reactor coolant pump (RCP). The applicant analyzed RCPs with respect to fatigue for the stretch power uprate and after a review and demonstrated that the stresses in the RCPs remain within ASME Code allowable limits. The applicant stated that the projected numbers of significant cycles in 60 years remain below the numbers of cycles in these evaluations, based on the numbers of design cycles; thus, the TLAAs remain valid for the period of extended operation.

4.3.1.5.2 Staff Evaluation

The staff reviewed LRA Section 4.3.1.5 to verify that, pursuant to 10 CFR 54.21(c)(1)(i), the analyses remain valid for the period of extended operation or that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The applicant stated in LRA Section 4.3.1.5 that, from stretch power uprate analyses, the CUFs for the IP2 and IP3 RCP main flange bolts are 0.44 and 0.32, respectively. The applicant stated that these usage factor calculations are based on the design discussed in LRA Section 4.3.1 and determined that the analyses remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). During an onsite audit, the staff noted that LRA Table 4.3-1 includes IP2 design transients whose 60-year projections exceed design cycles. The staff asked the applicant to justify its conclusion that the TLAAs remain valid for the period of extended operation (Audit Item 12).

In its response, dated March 24, 2008, the applicant stated that these TLAAs remain valid, as stated, as long as the analyzed values for the relevant transients are not exceeded. Since the Fatigue Monitoring Program is relied on to ensure that the numbers of transients do not exceed the analyzed values, the applicant will credit the Fatigue Monitoring Program for managing the effects of aging for the period of extended operation. The applicant also stated that it will revise LRA Sections 4.3.1.5 among others, and LRA Table 4.1-2 to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). The staff verified that the applicant's amendment, dated March 24, 2008, included the changes to LRA Section 4.3.1.5.

The staff finds the applicant's response acceptable because the applicant will manage the effects of fatigue for the RCPs by the Fatigue Monitoring Program for both IP2 and IP3, in accordance with 10 CFR 54.21(c)(1)(iii), rather than relying on an analysis performed in accordance with 10 CFR 54.21(c)(1)(i). SER Section 3.0.3.2.6 documents the staff's evaluation of the applicant's Fatigue Monitoring Program. The staff concludes that the applicant's aging management is consistent with the recommendations of the SRP-LR and satisfies the applicable regulatory requirements.

4.3.1.5.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of RCPs in LRA Sections A.2.2.2.1 and A.3.2.2.1. In response to the staff's question as described above, the applicant revised LRA Sections A.2.2.2.1 and A.3.2.2.1 to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). The staff verified that the applicant's amendment, dated March 24, 2008, included the changes to LRA Sections A.2.2.2.1 and A.3.2.2.1.

On the basis of its review of the UFSAR supplement, the staff finds that the summary description of the applicant's actions to address RCP fatigue analysis is adequate.

4.3.1.5.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the RCP, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.1.6 Control Rod Drive Mechanisms

4.3.1.6.1 Summary of Technical Information in the Application

LRA Section 4.3.1.6 describes the evaluation performed for the control rod drive mechanisms (CRDMs). The applicant originally analyzed the CRDMs in the generic component report and then reevaluated them for the power uprate. LRA Tables 4.3-11 and 4.3-12 present CUF values for the CRDMs for IP2 and IP3, respectively. The applicant stated that the numbers of analyzed design transients in these fatigue analyses will not be exceeded in 60 years of operation and thus these TLAAs remain valid through the period of extended operation.

4.3.1.6.2 Staff Evaluation

The staff reviewed LRA Section 4.3.1.6 to verify that, pursuant to 10 CFR 54.21(c)(1)(i), the analyses remain valid for the period of extended operation or that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The applicant listed the CUF values for various CRDM components in LRA Tables 4.3-11 for IP2 and 4.3-12 for IP3. As documented in the Audit and Review Report, the staff noted that these CUFs were derived from the results of Indian Point stretch power uprate nuclear steam supply engineering reports. The applicant stated that these usage factor calculations are based on the design discussed in LRA Section 4.3.1 and determined that the analyses remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). During an onsite audit, the staff noted that LRA Table 4.3-1 includes IP2 design transients whose 60-year projections exceed design cycles. The staff asked the applicant to justify its conclusion that TLAAs remain valid for the period of extended operation (Audit Item 12).

In its response, dated March 24, 2008, the applicant stated that these TLAAs remain valid, as stated, as long as the analyzed values for the relevant transients are not exceeded. Since the Fatigue Monitoring Program is relied on to ensure that the numbers of transients do not exceed the analyzed values, IP2 and IP3 will credit the Fatigue Monitoring Program for managing the effects of aging for the period of extended operation. The applicant also stated that it will revise LRA Section 4.3.1.6 to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). The staff verified that the applicant’s amendment, dated March 24, 2008, included the changes to LRA Section 4.3.1.6.

The staff finds the applicant’s response acceptable because the applicant will manage the effects of fatigue for the CRDMs by the Fatigue Monitoring Program for both IP2 and IP3, in accordance with 10 CFR 54.21(c)(1)(iii), rather than relying on an analysis performed in accordance with 10 CFR 54.21(c)(1)(i). By letter dated March 24, 2008, the applicant amended the LRA according to its above response. SER Section 3.0.3.2.6 documents the staff's evaluation of the applicant's Fatigue Monitoring Program. The staff concludes that the applicant's aging management is consistent with the recommendations of the SRP-LR and satisfies the applicable regulatory requirements.

4.3.1.6.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of the CRDMs in LRA Sections A.2.2.2.1 and A.3.2.2.1. In response to the staff's question as described above, the applicant revised LRA Sections A.2.2.2.1 and A.3.2.2.1 to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). The staff verified that the applicant's amendment, dated March 24, 2008, included the changes to LRA Sections A.2.2.2.1 and A.3.2.2.1.

On the basis of its review of the UFSAR supplement, the staff finds that the summary description of the applicant's TLAA evaluation of the CRDMs is adequate.

4.3.1.6.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the CRDMs, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.1.7 Class 1 Heat Exchangers

4.3.1.7.1 Summary of Technical Information in the Application

LRA Section 4.3.1.7 describes the evaluation performed for the Class 1 heat exchangers. The applicant calculated a projected CUF of 0.13 expected in 60 years for the regenerative heat exchangers and stated that the TLAAs for the heat exchanger fatigue remain valid for the period of extended operation. The applicant also stated that, based on design documents, the auxiliary heat exchangers are not the limiting component in the chemical and volume control system; instead, the charging nozzles are more limiting. NUREG/CR-6260 identifies the charging nozzles as one location that requires environmental adjustments to the fatigue analysis; thus, the charging nozzles will be evaluated with the other NUREG/CR-6260 locations.

4.3.1.7.2 Staff Evaluation

The staff reviewed LRA Section 4.3.1.7 to verify that, pursuant to 10 CFR 54.21(c)(1)(i), the analyses remain valid for the period of extended operation or that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

In LRA Section 4.3.1.7, the applicant stated that, with regard to fatigue, the auxiliary heat exchangers are not the limiting components in the chemical and volume control system. The charging nozzles are more limiting. During an onsite audit, the staff asked the applicant to clarify which nozzle (the nozzle in the heat exchanger or the nozzle in the RCS piping) it referred to in the statement (Audit Item 142).

In its response dated March 24, 2008, the applicant stated the following:

> WCAP-12191, Section 2.4, Conclusion 3, says the charging nozzle is limiting compared to the auxiliary heat exchangers. From WCAP-12191, Section 2.3, it is clear that the nozzles being discussed are the RCS piping nozzles (the normal nozzle in the cold leg and the alternate nozzle in the hot leg).
>
> LRA Section 4.3.1.7 will be clarified to specify that the nozzle is the nozzle at the RCS cold leg piping.

In the same letter, the applicant amended its LRA to reflect the above changes. Because the applicant clarified which charging nozzle it was referring to in the LRA, the staff finds the applicant's response acceptable.

In LRA Section 4.3.1.7, the applicant stated that the regenerative heat exchanger was the controlling heat exchanger as it relates to fatigue and that the projected 60-year CUF for the IP2 regenerative heat exchanger is 0.13. The applicant also stated that there is no plant-specific evaluation for the IP3 auxiliary heat exchangers; however, the similarity in design and operation of the two units indicate that the projected CUF results would be similar. As documented in the Audit and Review Report, the staff noted that this CUF was derived from an evaluation report for IP2. The staff asked the applicant to justify why the IP3 heat exchanger CUF is comparable to the IP2 CUF (Audit Item 17).

In its response, dated March 24, 2008, the applicant stated the following:

> As can be seen by review of Table 4.3-1 and 4.3-2, IP2 is projected to have more cycles of heatups, cooldowns, and reactor trips than IP3, based in part on IP3 having learned lessons from the early operation of IP2. Based on these projections, it is expected that the IP2 CUF will exceed the IP3 CUF. Conservatively, assume the CUFs approximately the same. As identified in LRA Section 4.3.1.7, since the IP2 CUF is only 0.13, it follows that the IP3 CUF is also well below the limit of 1.

The staff finds the applicant's response acceptable because the applicant has explained that IP3 has incorporated lessons learned from the early operation of IP2; therefore, it is expected that the IP2 CUF will exceed the IP3 CUF. The applicant committed to include enhancements in the IP3 Fatigue Monitoring Program that will provide additional monitoring of the heat exchanger cycling (Commitment No. 6).

During the audit, the staff asked the applicant to explain why it claimed that the TLAA for the heat exchanger fatigue remains valid for the period of extended operation (Audit Item 12). In its response, dated March 24, 2008, the applicant stated the following:

> These TLAA [sic] remain valid as stated as long as the analyzed values for the relevant transients are not exceeded. Since the Fatigue Monitoring Program (FMP) is relied on to assure that the numbers of transients do not exceed the analyzed values, IPEC will credit the FMP for managing the effects of aging for the period of extended operation.

The applicant also stated that it will revise LRA Section 4.3.1.7 to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). The staff verified that the applicant's amendment, dated March 24, 2008, included the changes to LRA Section 4.3.1.7.

The staff finds the applicant's response acceptable, because the applicant will manage the effects of fatigue on the Class 1 heat exchangers for both IP2 and IP3 by the Fatigue Monitoring Program, in accordance with 10 CFR 54.21(c)(1)(iii), rather than relying on an analysis performed in accordance with 10 CFR 54.21(c)(1)(i). SER Section 3.0.3.2.6 documents the staff's evaluation of the applicant's Fatigue Monitoring Program. The staff concluded that the applicant's AMP satisfies the criteria in the SRP-LR and satisfies the applicable regulatory requirements.

4.3.1.7.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of Class 1 heat exchangers in LRA Sections A.2.2.2.1 and A.3.2.2.1. In response to the staff's question as described above, the applicant revised LRA Sections A.2.2.2.1 and A.3.2.2.1 to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). The staff verified that the applicant's amendment dated March 24, 2008, included the changes to LRA Sections A.2.2.2.1 and A.3.2.2.1.

On the basis of its review of the UFSAR supplement, the staff finds that the summary description of the applicant's TLAA evaluation of the Class 1 heat exchangers is adequate.

4.3.1.7.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for Class 1 heat exchangers, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.1.8 Class 1 Piping and Components

4.3.1.8.1 Summary of Technical Information in the Application

LRA Section 4.3.1.8 describes the evaluation performed for Class 1 piping and components. The following components were a part of the evaluation:

- American National Standards Institute (ANSI) B31.1 piping
- pressurizer surge line piping
- thermowells
- charging system piping
- IP2 Loop 3 accumulator nozzle

The applicant evaluated projected thermal cycles for 60 years of plant operation for both IP2 and IP3 ANSI B31.1 piping. The applicant determined that the maximum IP2 and IP3 surge line piping CUF occurred at the pipe side of the pressurizer nozzle safe-end with a value of 0.60. Thermowells associated with the pressurizers that are based on 200 heatup and cooldown cycles, and identified by Westinghouse, produced CUF values of 0.021. The charging system piping for both IP2 and IP3 will be analyzed, taking into account environmental adjustments in LRA Section 4.3.3, because it is a NUREG/CR-6260 location. The applicant performed a fatigue analyses on the IP2 Loop 3 accumulator nozzle to justify continued operation without a thermal sleeve.

4.3.1.8.2 Staff Evaluation

The staff reviewed LRA Section 4.3.1.8 to verify that, pursuant to 10 CFR 54.21(c)(1)(i), the analyses remain valid for the period of extended operation or that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

During an onsite audit, the staff reviewed LRA Section 4.3.1.8 and noted that the applicant referenced both ANSI B31.1 and United States of America Standard (USAS) B31.1. The staff asked the applicant to explain why it was not consistent when referencing this code (Audit Item 143).

In its response, dated March 24, 2008, the applicant stated the following:

> Throughout the evolution of this code, the fatigue analysis requirements have remained fundamentally the same, and fundamentally different from ASME Section III fatigue analysis requirements. As the intention here is only to separate B31.1 fatigue analyses from Section III analyses, the distinction between ASA—USAS—ANSI—ASME is not critical to the discussion. Consequently, the LRA will be amended as follows. The discussion above will be added to the LRA Section 4.3.1.8. The title of the first subsection of LRA Section 4.2.1.8 will be changed to “B31.1 Piping.” In addition, all reference to B31.1 in the remainder of the LRA will be changed to “B31.1” with no prefix.

In a letter dated March 24, 2008, the applicant amended the LRA to reflect the above changes. Because the LRA now reflects a consistent code, the staff finds the applicant’s response acceptable.

During the audit, the staff reviewed LRA Section 4.3.1.8 and noted that the applicant stated, “The IP2 charging system piping failure analyses determined the limiting CUF for the charging nozzle as 0.99 for number of analyzed transients shown in the last nine entries in Table 4.3.1.” The staff asked the applicant to explain the conservatism behind projecting no transient conditions for “the charging nozzle flow shutoff with delayed return to service” (Audit Item 102).

In its response, dated March 24, 2008, the applicant stated the following:

> The conservatism is in the ASME fatigue curves, which are drawn well below the experimental points where cracking actually occurred. There is no specific conservatism in the assumption of zero cycles of this one particular transient, “charging flow shutoff with delayed return to service”; however, conservatism does exist in the analysis from other numbers of transient cycles being less than the analyzed values.

> WCAP-12191, Revision 3, “Transient and Fatigue Cycle Monitoring Program Transient History Evaluation Report for Indian Point Unit 2—Addendum 1” provides the basis for the IP2 transient cycles that are tracked in procedure 2-PT-2Y015. Table 2.3-3 of WCAP-12191, indicates the projected number of cycles based on the detailed review of actual plant data through 10/31/99, and shows this projection results in an acceptable CUF.
>
> WCAP-12191, Revisions 2 had 5, analyzed cycles of charging flow shutoff with delayed return to power. Revision 3 modified the analyzed numbers of cycles based on operating history. While the analyzed number for charging flow shutoff with delayed return to power was reduced to 0, the analyzed numbers for other events were increased.

The staff reviewed the applicant’s response and noted that the applicant justified its no-transient condition for “charging flow shutoff with delayed return to service” by increasing the analyzed numbers for other events. The staff reviewed the applicant’s Fatigue Monitoring Program, which tracks cycles such as charging flow shutoff with delayed return to service, and noted that this program includes a periodic assessment of the number of accumulated cycles. The program takes corrective action if any transient approaches its number of analyzed cycles, which may include an update of the fatigue usage calculation. The staff noted that the Fatigue Monitoring Program will update the CUF for the charging nozzle if a charging flow shutoff with delayed transient occurs. Therefore, the staff finds the applicant’s response acceptable.

The staff noted that the applicant justified its zero projection for letdown flow shutoff with delayed return to service and charging flow shutoff with prompt return to service by pointing out that the projected value is not used to calculate the CUF. The staff noted that the Fatigue Monitoring Program will update the CUF if the projected value exceeds analyzed cycles. In addition, the applicant explained in its response to Audit Question 102 that it will rely on the Fatigue Monitoring Program to manage the effects of aging from fatigue. Since the applicant will monitor the number of cycles and will take the required action if the analyzed numbers are approached, the projected numbers of cycles, standing alone, are therefore not important. On this basis, the staff finds the applicant’s response acceptable.

During the audit, the staff reviewed LRA Section 4.3.1.8 and noted that an analysis was done specifically for the IP2 Loop 3 accumulator nozzle and not for the other accumulator nozzles for IP2 and IP3. The staff asked the applicant to explain, in detail, why it conducted an analysis specifically for the IP2 Loop 3 accumulator nozzle (Audit Item 117).

In its response, dated March 24, 2008, the applicant stated the following:

> As stated in LRA Section 4.3.1.8, these nozzles were designed and built to USAS B31.1 and did not require the calculation of a CUF. However, after a period of operation, IP2 discovered that the Loop 3 accumulator nozzle thermal sleeve was no longer in place. IP2 performed a fatigue analysis of this nozzle (without a thermal sleeve) to show that it was acceptable for service in that condition. The analysis was done specifically for this one nozzle and does not apply to the remaining nozzles as the thermal sleeves remain in place.

The applicant explained satisfactorily why it only included the IP2 Loop 3 accumulator nozzle discussion in the LRA. The applicant explained that it conducted an analysis of the IP2 Loop 3 accumulator nozzle after the discovery that the thermal sleeve for this nozzle was no longer in place. On this basis, the staff finds the applicant's response acceptable.

During an onsite audit, the staff reviewed LRA Tables 4.3-1 and 4.3-2, which list the design transient cycles and transient cycles projected for 60 years of plant operation. The staff noted that LRA Table 4.3-1 includes IP2 design transients whose 60-year projections exceed design cycles. However, LRA Section 4.3.1.8 states that the projected numbers of transient cycles used for pressurizer surge line piping, charging system piping, and IP2 Loop 3 accumulator nozzle fatigue analyses remain within analyzed values; therefore, the TLAA remains valid through the end of the period of extended operation in accordance with the requirements of 10 CFR 54.21(c)(1)(i). The staff asked the applicant to justify this conclusion (Audit Item 12).

In its response, dated March 24, 2008, the applicant stated the following:

> LRA Sections 4.3.1.2 thru 4.3.1.8 and LRA Table 4.1-2 will be revised to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

In a letter dated March 24, 2008, the applicant amended its LRA in accordance with the above response. The staff reviewed the change and noted that the correction stated is reflected in the LRA.

The staff finds the applicant's response acceptable, because the applicant will manage the effects of fatigue on the Class 1 piping and components for both IP2 and IP3 by the Fatigue Monitoring Program, in accordance with 10 CFR 54.21(c)(1)(iii), rather than relying on an analysis performed in accordance with 10 CFR 54.21(c)(1)(i). SER Section 3.0.3.2.6 documents the staff's evaluation of the applicant's Fatigue Monitoring Program. The staff concluded that the applicant's AMP satisfies the criteria in the SRP-LR and satisfies the applicable regulatory requirements.

4.3.1.8.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of Class 1 piping and components in LRA Sections A.2.2.2.1 and A.3.2.2.1. In response to the staff's question as described above, the applicant revised LRA Sections A.2.2.2.1 and A.3.2.2.1 to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). The staff verified that the applicant's amendment, dated March 24, 2008, included the changes to LRA Sections A.2.2.2.1 and A.3.2.2.1.

On the basis of its review of the UFSAR supplement, the staff finds that the summary description of the applicant's TLAA evaluation of Class 1 piping and components is adequate.

4.3.1.8.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for Class 1 piping and components, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.2 Non-Class 1 Fatigue

4.3.2.1 Summary of Technical Information in the Application

LRA Section 4.3.2 describes the evaluation performed for non-Class 1 piping and components. The applicant performed an evaluation of the validity of the 7000-thermal-cycles assumption used in the associated fatigue analysis for 60 years of plant operation and stated that the TLAA analysis is valid for the 60 years of plant operation.

4.3.2.2 Staff Evaluation

The staff reviewed LRA Section 4.3.2 to verify that, pursuant to 10 CFR 54.21(c)(1)(i), the analyses remain valid for the period of extended operation.

During an onsite audit, the staff noted an apparent inconsistency in LRA Section 4.3.2. In the second paragraph, the applicant stated that the RHR heat exchanger is a potential TLAA, while in the fourth paragraph the applicant stated that "no fatigue analyses for these heat exchangers have been identified." The staff asked the applicant to clarify these statements (Audit Item 144).

In its response, dated March 24, 2008, the applicant stated that the assumption in LRA Section 4.3.2 that the RHR heat exchanger had a TLAA was a conservative assumption, based solely on a statement in the original equipment specification and the final safety analysis reports that the component was designed based on 200 cycles. Given that no fatigue analysis for the RHR heat exchangers has been found, the assumption that there is a potential TLAA for this component has no basis.

The staff finds the applicant's response acceptable because the applicant clarified that a fatigue analysis for the RHR heat exchangers was not identified; therefore, a TLAA is not applicable.

The applicant further stated that it will revise LRA Section 4.3.2 as follows:

> Piping and In-line Components
> The design of ASME III Code Class 2 and 3 piping systems incorporates the Code stress reduction factor for determining acceptability of piping design with respect to thermal stresses. In general, 7000 thermal cycles are assumed, allowing a stress reduction factor of 1.0 in the stress analyses. IPEC evaluated the validity of this assumption for 60 years of plant operation. The results of this evaluation indicate that the 7000 thermal cycle assumption is valid and bounding for 60 years of operation. Therefore, the pipe stress calculations are valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).
>
> Non-piping Components
> Review of potential TLAAs for IPEC non-Class 1 components identified no TLAA.

The staff determined that the plant does not operate in a cycling mode that would expose the piping to more than 7000 cycles in 60 years. On this basis, the staff concludes that the ASME Code B31.1 and Section III, Class 2 and 3, piping analyses remain valid, in accordance with

10 CFR 54.21(c)(1)(i).

4.3.2.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of non-Class 1 fatigue in LRA Sections A.2.2.2.2 and A.3.2.2.2, as amended by letter dated March 24, 2008. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's TLAA evaluation of non-Class 1 piping and components is adequate.

4.3.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that, for non-Class 1 fatigue, the analyses remain valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.3 Effects of Reactor Water Environment on Fatigue Life

4.3.3.1 Summary of Technical Information in the Application

LRA Section 4.3.3 summarizes the applicant's evaluation of the effects of the RCS environment on fatigue life of piping and components under Generic Safety Issue (GSI)-190, "Fatigue Evaluation of Metal Components for 60-Year Plant Life," for the period of extended operation. The fatigue data for the ASME Code, Section III, fatigue curves result from tests performed in air at room temperature and constant strain rate. Concerns over the potential effect of elevated temperature, reactor coolant chemistry environments, and different strain rates prompted staff-sponsored research and studies. Results are documented in NUREG/CR-5999, "Interim Fatigue Design Curves for Carbon, Low-Alloy, and Austenitic Stainless Steels in LWR Environments." Subsequent research and studies, including NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," refined the earlier study methods.

Based on NUREG/CR-6260 and the IP2 and IP3 plant design, the following component locations were shown to be the most sensitive to reactor water environmental effects:

- RV shell and lower head
- RV inlet and outlet nozzles
- pressurizer surge line (including hot leg and pressurizer nozzles)
- RCS piping charging system nozzle
- RCS piping safety injection nozzle
- RHR Class 1 piping

The applicant evaluated the limiting locations using the guidelines of the GALL Report, Volume 2, Section X.M1, which calls for following the guidance (formulas) of (1) NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels," issued April 1999, for austenitic stainless steel; and (2) NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," issued February 1998, for carbon steel and low-alloy steel to calculate environmentally assisted fatigue correction factors (F_{en}). LRA Tables 4.3-13 (IP2) and 4.3-14 (IP3) list the environmentally adjusted CUF values for the applicant's NUREG/CR-6260 limiting locations.

4.3.3.2 Staff Evaluation

The staff reviewed LRA Section 4.3.3 to verify that, pursuant to 10 CFR 54.21(c)(1)(ii), the analyses have been projected to the end of the period of extended operation or that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The staff reviewed LRA Section 4.3.3 against SRP-LR Section 4.3.3.2, "Generic Safety Issue." The SRP-LR recommends that license renewal applicants address GSI-190. To assess the impact of the reactor coolant environment on a sample of critical components, the SRP-LR states that applicants should address the recommendations as follows:

(1) The critical components include, as a minimum, those selected in NUREG/CR-6260.

(2) Evaluation of the sample of critical components applied environmental correction factors to the ASME Code fatigue analyses.

(3) Formulas for calculating the environmental life correction factors are those in NUREG/CR-6583 for carbon and low-alloy steels and those in NUREG/CR-5704 for austenitic stainless steels or approved technical equivalents.

The staff reviewed LRA Section 4.3.3 and noted that, for the bottom head to shell transition, the RV inlet nozzle, and the RV outlet nozzle for IP2 and IP3, the applicant projected its analyses to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

As documented in the Audit Report, the staff confirmed that the CUFs for the above-mentioned locations are correct and that the applicant accounted for increases to the CUF associated with the stretch power uprate. The projected 60-year CUFs for these locations are all less than one. On this basis, the staff concludes that the analyses performed for these components were projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

The staff reviewed LRA Section 4.3.3 to verify that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) for IP2 and IP3 will be adequately managed for the period of extended operation in the (1) pressurizer surge line nozzle, (2) surge line piping to safe-end weld, (3) RCS piping charging system nozzle, (4) RCS piping safety injection nozzle, and (5) RHR Class 1 piping. In a letter dated June 11, 2008, the applicant amended the LRA to note that, for the bottom head to shell transition, the RV inlet nozzle and the RV outlet nozzle locations will no longer be dispositioned under the requirements of 10 CFR 54.21(c)(1)(ii). For these locations, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(iii).

During an onsite audit, the staff reviewed LRA Section 4.3.3 and noted that LRA Tables 4.3-13 (IP2) and 4.3-14 (IP3) indicate that some of the listed NUREG/CR-6260 locations with environmentally adjusted CUFs are projected to exceed a value of one during the period of extended operation. The staff also noted that several locations currently do not have an environmentally adjusted CUF. These include two components from LRA Table 4.3-13 (IP2)—

the RCS piping safety injection nozzle and the RHR Class 1 piping—and three components from LRA Table 4.3-14 (IP3)—the RCS piping charging system nozzle, RCS piping safety injection nozzle, and RHR Class 1 piping. The staff asked the applicant to explain why the number of components between the IP2 and IP3 without environmentally adjusted CUFs differ. The staff also noted that, on LRA pages 4.3-22 and 4.3-23, the applicant provided a corrective action plan to address the environmentally assisted fatigue issue before the calculated CUF exceeds a value of one. The staff asked the applicant to confirm that the fatigue usage factors will be developed for the locations noted in LRA Tables 4.3-13 and 4.3-14 and to commit to a corrective action plan.

In a letter dated January 22, 2008, the applicant submitted LRA Amendment 2. The applicant revised the list of TLAA resolution options in LRA Tables 4.1-1 (IP2) and 4.1-2 (IP3). For the TLAA entitled, "Effects of Reactor Water Environment on Fatigue Life," the applicant stated that it will use an aging management program (AMP) to manage this aging effect, in accordance with 10 CFR 54.21(c)(1)(iii). The applicant also provided revised corrective actions in LRA Amendment 2. The applicant confirmed that the fatigue usage factors will be developed for the locations identified in LRA Tables 4.3-13 and 4.3-14 and committed to a corrective action plan (Commitment 33).

In LRA Amendment 2, the applicant also provided additional information on the Fatigue Monitoring Program. Originally, the applicant's Fatigue Monitoring Program took an exception for "detection of aging effects," which indicates that the applicant would not perform periodic updates of fatigue usage calculations. As stated in Commitment 33, the applicant's Fatigue Monitoring Program includes the assessment of the impact of the reactor water environment on critical components, as identified in NUREG/CR-6260. By letter dated June 11, 2008, the applicant amended the LRA and removed the above mentioned exception. The staff notes that removal of the exception makes the Fatigue Monitoring Program consistent with the GALL Report AMP X.M1. SER Section 3.0.3.2.6 documents the staff's evaluation of the applicant's Fatigue Monitoring Program. The staff concluded that the applicant's AMP satisfies the criteria in the SRP-LR and applicable regulatory requirements.

During the onsite audit, the staff questioned the applicant as to why a difference exists between IP2 and IP3 in terms of the number of components without environmentally adjusted CUFs (Audit Item 116). In its response, dated March 24, 2008, the applicant stated the following:

> Neither unit (IP2 nor IP3) had CUF's for three locations (the charging systems nozzle, the safety injection nozzle, or the RHR Class 1 piping) as part of the original design. All of these locations were built to USAS B31.1 rather than ASME III.
>
> After a period of operation, IP2 noted that they were using the charging system nozzle at a higher rate than recommended by the OEM. (i.e., they weren't using the alternate charging nozzle as frequently as was recommended.) Consequently, IP2 performed a fatigue analysis of the charging nozzle to assess the effect of this operation. The result of that analysis is quoted in LRA Table 4.3-13.
>
> IP3 did not perform such a calculation and they therefore have no corresponding CUF in Table 4.3-14.

The staff has reviewed the applicant's description of the differences in operating history between IP2 and IP3, and finds the applicant's explanation of these differences and the resulting impact on the number of affected components to be acceptable. The difference in operating histories between IP2 and IP3 contributed to the difference between the IP2 and IP3 charging system nozzles, as presented in LRA Tables 4.3-13 and 4.3-14.

As documented in the Audit Report, the staff reviewed the applicant's calculation for the F_{en}. The staff noted that, for low-alloy steel, a value of 0.0 for the input of dissolved oxygen was used in NUREG/CR-6583, Equation 6.5b. The staff noted that Entergy maintains a dissolved oxygen content of less than or equal to 0.005 parts per million (ppm) during power operation, in accordance with its operating procedure. This dissolved oxygen content is less than 0.05 ppm, which is the limit, defined in NUREG/CR-6583, Equation 5.5c. Therefore, the value of 0.0 for the input of dissolved oxygen is appropriate in NUREG/CR-6583, Equation 6.5b. In RAI 4.3.1.8-1, dated April 18, 2008, the staff asked the applicant to describe how other various environmental effects are factored into the calculation of the CUF using F_{en} values.

In its response, dated May 16, 2008, the applicant provided the equations used for calculating F_{en} and the factors that can affect the F_{en} value. Based on its review of the applicant's response, the staff finds that for low-alloy steel it is appropriate to eliminate the sulfur content, temperature, and strain rate from NUREG/CR-6583, Equation 6.5b, based on the value obtained from the dissolved oxygen content maintained at IP2 and IP3. For stainless steel, the staff observed that the applicant used the maximum F_{en} value of 15.35 for the material temperature, strain rate, and dissolved oxygen content. Based on the staff's review of the applicant's F_{en} calculation and its response to RAI 4.3.1.8-1, the staff confirms that the applicant has conservatively calculated the F_{en} value for austenitic stainless steel, in accordance with the guidance in NUREG/CR-5704, and appropriately calculated the F_{en} value for low-alloy steel pursuant to guidance in NUREG/CR-6583.

Based on its review discussed above, the staff concludes that the applicant correctly accounted for the different environmental factors that are inputs in calculating the F_{en} factor for low-alloy steel and used a conservative value of F_{en} for austenitic stainless steel. Therefore, the staff finds that the applicant's F_{en} values were calculated appropriately. The staff's concern described in RAI 4.3.1.8-1 is resolved.

As documented in the Audit Report, the staff reviewed the applicant's basis documents. The staff noted that these documents did not list the alert values that trigger the initiation of corrective actions for the Fatigue Monitoring Program. The staff asked the applicant to identify the alert values (Audit Item 119).

In its response, dated March 24, 2008, the applicant stated the following:

> IPEC Procedure 2-PT-2Y15 calculates "alert levels" by adding twice the number of cycles that occurred in the last fuel cycle to the total number of cycles to date. Corrective action is initiated if this alert level exceeds the number of analyzed transients.
>
> In other words, if the number of cycles is projected to remain at or below the analyzed level for 2 additional fuel cycles, no corrective action is required.

As documented in the Audit Report, the staff reviewed the applicant's procedure on site and confirmed how the alert level is calculated.

In RAI 4.3.1.8-2, dated April 18, 2008, the staff asked the applicant to further explain its corrective actions and the frequency of such actions, if the alert level is approached. In its response, dated May 16, 2008, the applicant explained that the frequency of updates for the counting of plant transients will be at least once each operating cycle, and these updates determine if design transients may be exceeded before the next update. The applicant also stated that corrective actions will be taken before the analyzed transient cycles are exceeded.

The staff finds the applicant's response acceptable because the applicant will perform periodic updates on the number of plant transients. This will ensure that design transients will not be exceeded and will allow adequate time for the applicant to initiate corrective actions based on the calculated alert level from the applicant's procedure. These corrective actions include further reanalysis or repair or replacement of the affected components. The staff also finds the applicant's response acceptable because the applicant will include new or updated CUF calculations, as appropriate, for all NUREG/CR-6260 locations identified in LRA Tables 4.3-13 and 4.3-14 as part of the Fatigue Monitoring Program. In addition, the staff finds that the applicant will monitor the number of cycles that occur and ensure that they do not exceed the analyzed number of transients. The staff's concern described in RAI 4.3.1.8-2 is resolved.

During the audit, the staff reviewed LRA Section 4.3.3 and noted that the applicant made a commitment on LRA page 4.3-22 to reanalyze the pressurizer fatigue analysis. As stated in the LRA, the IP2 pressurizer surge nozzle has an environmentally adjusted CUF less than 1.0, while the IP3 pressurizer surge nozzle has an environmentally adjusted CUF of greater than 1.0. This is because the IP3 surge nozzle calculation includes the effects of the insurges/outsurges seen by these nozzles, while the IP2 analysis does not include these effects. The applicant stated that it will re-analyze the pressurizer surge line nozzle for both units to include insurge/outsurge and environmental effects. The staff asked the applicant if there was an official commitment made to perform this reanalysis. In its response, dated January 22, 2008, the applicant stated that the pressurizer reanalysis is included in Commitment 33. On the basis that the applicant has committed to performing the pressurizer fatigue reanalysis, the staff finds the response acceptable (Commitment 33).

During the audit, the staff reviewed LRA Section 4.3.3 and noted that the applicant misquotes NUREG/CR-6260 in LRA page 4.3-21, third paragraph, as having fatigue curves incorporating environmental effects and incorrectly references NUREG/CR-6260 in LRA page 4.3-22, third paragraph. The staff asked the applicant to clarify its statements in both instances (Audit Item 147).

In its response, dated March 24, 2008, the applicant stated the following:

> The LRA paragraph will be revised to read as follows. "NUREG/CR-6260 identified locations of interest for consideration of environmental effects in several plant designs. Section 5.5 of NUREG/CR-6260 identified the following component locations to be evaluated for the environmental effects on fatigue for IPEC vintage Westinghouse plants. These locations and the subsequent calculations are directly relevant to IPEC.

In the same letter, the applicant amended LRA Section 4.3.3 as described above. The staff finds the applicant's response acceptable, because the applicant amended LRA page 4.3-21 to correct its discussion of NUREG/CR-6260 statements.

In LRA Section 4.3.3, the applicant stated that at least 2 years prior to entering the period of extended operation, for the locations identified in NUREG/CR-6260 for Westinghouse PWRs such as IP2 and IP3, it would refine the fatigue analyses, manage the effects of aging, or repair or replace the affected locations before exceeding a CUF of 1.0. The staff noted during the audit that it was unclear as to which environmental-assisted fatigue plant-specific locations Entergy would implement one of the above mentioned options. In response to the staff's question, the applicant amended the LRA by letter dated January 22, 2008. The revised paragraph now reads as follows:

> At least 2 years prior to entering the period of extended operation, for the locations identified in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3), under the Fatigue Monitoring Program, IP2 and IP3 will implement one or more of the following.
>
> (1) Consistent with the Fatigue Monitoring Program, Detection of Aging Effects, update the fatigue usage calculations using refined the fatigue analyses to determine valid CUFs less than 1.0 when accounting for the effects of reactor water environment. This includes applying the appropriate F_{en} factors to valid CUFs determined in accordance with one of the following.
>
> For locations in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3) with existing fatigue analysis valid for the period of extended operation, use the existing CUF.
>
> Additional plant-specific locations with a valid CUF may be evaluated. In particular, the pressurizer lower shell will be reviewed to ensure the surge nozzle remains the limiting component.
>
> Representative CUF values from other plants, adjusted to or enveloping the IPEC plant-specific external loads may be used if demonstrated applicable to IPEC.
>
> An analysis using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case) may be performed to determine a valid CUF.
>
> (2) Consistent with the Fatigue Monitoring Program, Corrective Actions, repair or replace the affected locations before exceeding a CUF of 1.0.

The staff finds the applicant's commitment acceptable because the applicant, through LRA Amendment 2, corrected the third paragraph on LRA page 4.3-22 by referencing LRA Tables 4.3-13 and 4.3-14 to clearly indicate the affected plant-specific locations instead of referencing NUREG/CR-6260. Additionally, the staff finds that this commitment is consistent with 10 CFR 54.21(c)(1)(iii).

4.3.3.3 UFSAR Supplement

In a letter dated January 22, 2008, the applicant submitted LRA Amendment 2. The applicant revised its LRA Sections A.2.2.2.3 and A.3.2.2.3 regarding the UFSAR supplement summary description of the TLAA evaluation of the effects of reactor water environment on fatigue life. On the basis of its review of the revised UFSAR supplement, the staff has determined that the summary description of the applicant's TLAA evaluation of reactor water environment on fatigue life is adequate.

4.3.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the components identified in NUREG/CR-6260, the effects of aging on the intended functions will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.4 Environmental Qualification of Electric Equipment

The applicant's Environmental Qualification (EQ) of Electric Equipment Program is an aging management program that will manage the aging effects of EQ components with TLAAs. The TLAA of the EQ electrical components includes all long-lived, passive, and active electrical and instrumentation and control 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 loss-of-coolant accidents or high-energy line breaks. EQ equipment comprises safety-related equipment, nonsafety-related equipment whose failure could prevent satisfactory accomplishment of any safety-related function, and certain post-accident monitoring equipment.

As required by 10 CFR 54.21(c)(1), the applicant must provide a list of TLAAs in the LRA. The applicant shall demonstrate that:

- (i) The analyses remain valid for the period of extended operation;
- (iii) The analyses have been projected to the end of the period of extended operation; or
- (iii) The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.1 Summary of Technical Information in the Application

LRA Section 4.4 summarizes the evaluation of TLAAs associated with EQ of electric equipment for the period of extended operation. The applicant evaluated EQ electrical components using 10 CFR 50.49(f) qualification methods. Equipment qualification evaluations that specify a qualification duration of at least 40 years, but fewer than 60 years, are considered TLAAs for license renewal.

The applicant stated that these TLAAs have not been projected for the period of extended operation; rather, the aging effects associated with these analyses are managed by the Environmental Qualification of Electric Components Program in accordance with 10 CFR 54.21(c)(1)(iii). The EQ Program is an existing program established to meet the applicant's commitments for 10 CFR 50.49. Further, the applicant stated that the program is consistent with the GALL Report, Section X.E1, "Environmental Qualification of Electric Components."

4.4.2 Staff Evaluation

The staff reviewed LRA Section 4.4 and plant basis documents to determine whether the applicant provided adequate information to meet the requirement of 10 CFR 54.21(c)(1). For the electrical equipment identified in the EQ master list, the applicant uses 10 CFR 54.21(c)(1)(iii) in its TLAA evaluation to demonstrate that the aging effects of EQ equipment will be adequately managed during the period of extended operation. As required by 10 CFR 50.49, EQ components not qualified for the current license term are to be refurbished, replaced, or have their qualification extended before reaching the aging limits established in the evaluation. The Environmental Qualification of Electric Components Program ensures that these EQ components are maintained in accordance with their qualification bases. Aging evaluations for EQ components that specify a qualification of at least 40 years are TLAAs for license renewal.

The staff reviewed the EQ Program to determine whether it will ensure that the electrical and instrumentation and control components covered under this program will continue to perform their intended functions, consistent with the CLB during the period of extended operation.

The staff's evaluation of the components' qualification focused on how the EQ Program manages the aging effects to meet the requirements pursuant to 10 CFR 50.49.

The staff conducted an audit of the information provided in LRA Section B 1.10 and program basis documents. As documented in SER Section 3.0.3.1.4, the staff finds that the EQ Program, which the applicant stated is consistent with GALL Report, Section X.E1, is consistent with the EQ program in the GALL Report. Therefore, the staff finds that the EQ 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 Program provides reasonable assurance that the aging effects will be managed and that components within the scope of the EQ Program will continue to perform their intended functions for the period of extended operation.

4.4.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of EQ of electrical equipment in LRA Section A.2.1.9 and A.3.1.9 for IP2 and IP3, respectively. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address EQ of electric equipment is adequate.

4.4.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for EQ of electrical equipment, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.5 Concrete Containment Tendon Prestress Analyses

4.5.1 Summary of Technical Information in the Application

LRA Section 4.5 states that this section is not applicable because the IP2 and IP3 containment structures do not have prestressed tendons.

4.5.2 Staff Evaluation

The containments do not have prestressed tendons; therefore, the staff finds this TLAA is not applicable.

4.5.3 UFSAR Supplement

The staff concludes that a UFSAR supplement is not required because the containment structures do not have prestressed tendons.

4.5.4 Conclusion

On the basis of its review, the staff concludes this TLAA is not applicable.

4.6 Containment Liner Plate and Penetration Fatigue Analyses

4.6.1 Summary of Technical Information in the Application

In LRA Section 4.6, the applicant described a TLAA for the IP2 containment liner plate as follows:

> In 1973, a feedwater line cracked circumferentially resulting in damage to the liner plate causing containment liner plate buckling at the penetration for feedwater line #22. No repair was required for this buckling of the liner plate.
>
> Studies were performed to evaluate the effects of fatigue on the deformed area of the liner due to predicted high strain-limited cycle loading during its projected 40-year life. The evaluation used an AEC-approved maximum strain and concluded that the strain load endurance limit of the material was 450 cycles at 7.7 percent strain. The evaluation estimated that the containment liner was likely to see 50 LOCAs (concurrent with earthquakes) at 1 percent strain, and 8 cycles from containment testing (1 pre-startup full pressure test at 6.5 percent strain and 7 cycles at 3.25 percent strain). This combines to 58 cycles at assorted strain (6.5 percent maximum strain). The evaluation conservatively projected a worst case of 60 cycles at 6.5 percent strain. As this projection was so far below the allowed 450 cycles at 7.7 percent strain, no further analysis was performed.

The applicant stated that IP2 will not experience 50 loss-of-coolant accidents (concurrent with earthquakes) in 60 years of operation. Containment pressure testing is scheduled only once every 10 years. Therefore, the number of cycles experienced will continue to be less than the 60 cycles originally assumed and well below the 450-cycle limit in 60 years of operation. Therefore, the TLAA associated with the IP2 liner adjacent to the feedwater line #22 penetration remains valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

The applicant further indicated that no other TLAAs are associated with IP2 and IP3 containment liner plate or penetrations.

4.6.2 Staff Evaluation

The staff reviewed LRA Section 4.6 to verify that the analysis remains valid for the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(i).

During an onsite audit, the staff requested additional information about the 1973 feedwater line break event that resulted in buckling of the containment liner plate (Audit Item 30), as follows:

> (a) Describe in greater detail the event that resulted in the permanent liner plate deformation. When specifically did it occur? What was identified as the root cause? How was this corrected?
>
> (b) Discuss the history of ISI of the permanently deformed liner plate, from 1973 to the present.

The applicant provided the requested information in its response to Audit Item 30, dated March 24, 2008. In response to part (a) of the question, the applicant provided the requested history and corrective actions as documented in the letter dated March 24, 2008. In response to part (b) of the staff's question, the applicant stated the following:

> General visual examinations were conducted under the Containment Inservice Inspection Program between June 2004 and November 2004 for all accessible areas of the containment liner, including penetrations and airlocks, in accordance with Table IWE-2500, Category E-A, Item E1.11.
>
> Minor surface corrosion and/or coating deterioration were observed on the penetrations. This is general surface corrosion that has not resulted in any significant loss of material.
>
> The containment leak rate test at IP2 in 2006 was completed satisfactorily.

Upon further discussion with the applicant during the onsite audit, the staff became aware that the affected area of the containment liner (1) was covered with thermal insulation shortly after the accident, (2) is considered inaccessible by the applicant, and (3) is not considered for inspection under the ASME Code, Section XI, Subsection IWE accessibility for examination requirements. Consequently, there has been no inspection of the affected liner area since shortly after the 1973 event occurred.

Although the staff does not expect significant degradation to have occurred, the applicant was requested to verify the lack of degradation with a one-time inspection in connection with the applicant's Containment Inservice Inspection Program. By letter dated August 14, 2008, the applicant committed to conduct a one-time inspection of the affected area of containment liner before entering the period of extended operation (Commitment 35). The staff's evaluation of the Containment Inservice Inspection Program and the applicant's response to the related Audit Item 27 is documented in SER Section 3.0.3.3.2.

The staff finds that the original post-accident evaluation of allowable strain cycles will remain valid because the projected number of cycles for 60 years of operation is less than 50 cycles, as compared to an allowable number of 450 cycles. Therefore, this analysis is acceptable.

4.6.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of the containment liner plate and penetration fatigue analyses in LRA Sections A.2.2.4 and A.3.2.4. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address containment liner plate and penetration fatigue analyses is adequate.

4.6.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated that the containment liner plate and penetration fatigue analyses remain valid for the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(i). The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7 Other Plant-Specific TLAAs

LRA Section 4.7 summarizes the evaluation of the following plant-specific TLAAs:

- RCP flywheel analysis
- LBB
- steam generator flow-induced vibration and tube wear

4.7.1 Reactor Coolant Pump Flywheel Analysis

4.7.1.1 Summary of Technical Information in the Application

LRA Section 4.7.1 summarizes the evaluation of the RCP flywheel analysis for the period of extended operation. The RCP motors have flywheels to increase rotational inertia, prolong pump coastdown, and ensure a prolonged primary coolant flow to the core if electrical power to the pump is lost. The aging effect of concern was identified by the applicant as fatigue crack initiation and growth in the flywheel bore keyway from stresses from the motor upon startup. RG 1.14, "Reactor Coolant Pump Flywheel Integrity," recommends periodic volumetric inspection of flywheels.

The applicant inspects the RCP flywheels at least every 20 years, as required by Technical Specifications 5.5.5 (IP2) and 5.5.6 (IP3) and in accordance with the staff-approved WCAP-15666-A, which assumes 6000 start/stop cycles of an RCP. The 6000 start/stop cycles is an order of magnitude beyond the analyzed number of heatup and cooldown cycles in 60 years expected at IP2 and IP3 (i.e., 200 cycles). The analyzed number of cycles is far greater than the expected number of cycles, even assuming multiple RCP starts in each startup-shutdown cycle.

The applicant states that because the 6000 cycles that WCAP-15666-A assumes far exceeds the IP2 and IP3 cycles expected in 60 years, and because WCAP-15666-A is based on 60 rather than 40 years, the applicant's analysis does not meet the 10 CFR 54.3(a) definition for a TLAA. The applicant's analysis makes no time-limited assumptions, as defined by the current operating term or by a shorter operating term plus the period of extended operation requested in the license renewal application. Further, the applicant states that an evaluation is not applicable as the flywheel analysis is not a TLAA pursuant to 10 CFR 54.3(a)(3).

4.7.1.2 Staff Evaluation

As summarized above, the applicant stated that the 6000 pump start/stop cycles assumed in the Westinghouse WCAP-15666 analysis far exceeds the expected number of IP2 and IP3 cycles in 60 years. The applicant also stated that the analyzed number of heatup and cooldown cycles for 60 years of operation is 200 for IP2 and IP3. In RAI 4.7.1-4, dated December 21, 2007, the staff questioned the validity of comparing 6000 cycles in the WCAP-15666 analysis to 200 cycles of heatup/cooldown at IP2 and IP3. The staff questioned the values used for IP2 and IP3, in that for each of the 200 heatup/shutdown cycles, multiple RCP startups could make the total number of cycles higher than the number that was analyzed.

By letter dated January 17, 2008, the applicant responded that, as indicated in LRA Tables 4.3-1 and 4.3-2, the analyzed number of heatup and cooldown cycles for 60 years of operation is 200 for IP2 and IP3. The analyzed number of cycles is far greater than the expected number, even if multiple RCP starts are assumed in each startup shutdown cycle. Because the 6000 cycles assumed in the analysis far exceeds the expected cycles in 60 years, and because the analysis is based on 60 years rather than 40 years, this analysis does not meet the 10 CFR 54.3(a) criteria for a TLAA.

The applicant further stated that there may be multiple starts/stops per heatup; however, even if a conservative number of starts/stops of the limiting motor is assumed, the value is still well below 6000 cycles. One would have to assume an unrealistic 30 starts/stops for every heatup to get to 6000 starts for the limiting flywheel. Ten starts per heatup is a conservative estimate, and that only results in 2000 starts for 200 heatups.

The staff noted that LRA Table 4.3-1 shows that the RCP start/stop condition has 10,000 cycles. In RAI 4.7.1-2(a), dated December 21, 2007, the staff requested that the applicant clarify why the WCAP-15666 flywheel analysis did not use a 10,000-cycle RCP startup/stop condition. By letter dated January 17, 2008, the applicant responded that the 10,000 RCP starts shown in LRA Table 4.3-1 are considered for their impact on the entire RCS. This value applies to starts from any one of the four RCPs and, therefore, is not an appropriate value to use in the analysis for a single RCP motor flywheel. Heatup and cooldown cycles are limited to 200. The applicant further stated that even if 10 starts and stops for the limiting pump occur during each heatup and cooldown cycle, only 2000 RCP cycles will result. This is well below 6000 cycles criteria used in the Westinghouse flywheel analysis. The staff finds that the applicant's explanation is reasonable; therefore, the staff determines that 6000 is an acceptable number of cycles for the RCP flywheel analysis.

LRA Table 4.3-1 lists various normal, test, and abnormal conditions. Some of those conditions may affect flywheel operation and the structural integrity of the flywheel. However, the applicant only mentioned the RCP start/stop condition in WCAP-15666-A. In RAI 4.7.1-2(b), dated December 21, 2007, the staff asked whether other normal, test, and abnormal conditions in LRA

Table 4.3-1 should be used in WCAP-15666-A to analyze the flywheel. By letter dated January 17, 2008, the applicant responded that RG 1.14, Revision 1, Section C, Subsection 2, provides the regulatory position for flywheel design, and those guidelines were followed in the flywheel evaluation in WCAP-15666. The staff had previously reviewed and approved WCAP-15666 as documented in a May 5, 2003, letter from Herbert N. Berkow, NRC, to Robert H. Bryan, Chairman, Westinghouse Owner's Group, “Safety Evaluation of Topical Report WCAP-15666, ‘Extension of Reactor Coolant Pump Motor Flywheel Examination’” (TAC No. MB2819).

Section 2 (page 2-19) of WCAP-15666 states, “There are no significant mechanisms for inservice degradation of the flywheels, since they are isolated from the primary coolant environment….” Since the flywheels are isolated from the primary coolant environment, the remaining transients in LRA Table 4.3-1 have no effect on the flywheel operation and structural integrity.

The staff finds that the applicant has clarified that the 6000 pump start/stop events assumed in the flywheel analysis far exceed the potential start/stop events in the plant in 60 years and that the transient conditions other than the pump start/stop events in LRA Table 4.3-1 do not apply. Therefore, the RCP flywheel analysis does not meet the definition of a TLAA as defined in 10 CFR 54.3(a); specifically, the analysis does not involve time-limited assumptions defined by the current operating term.

As stated in LRA Section 4.7.1, the applicant considered only fatigue as a degradation mechanism for crack initiation and growth. In RAI 4.7.1-1, dated December 21, 2007, the staff questioned whether stress-corrosion cracking should be considered as a potential degradation mechanism in the flywheel, especially in the bore keyway, given the potential for an adverse environment, stress conditions, and material. By letter dated January 17, 2008, the applicant responded that the flywheel is a carbon steel component exposed to indoor air. Since the flywheel operates at ambient temperature in a dry indoor air environment, cracking from stress corrosion is not a plausible aging effect.

The applicant further explained that, although cracking from stress corrosion is an aging effect considered in the AMR of those components that are within the scope of license renewal and are subject to AMR, the RCP flywheel (RCP motor) is an active component that is not subject to AMR and, therefore, is not addressed by an AMR in LRA Section 3. The staff finds that the applicant has clarified that stress-corrosion cracking is not a degradation mechanism for the RPC flywheel. The staff also confirms that, because it is an active component, the RCP flywheel is not subject to an AMR.

In LRA Section 4.7.1, the applicant stated that the RCP flywheels are inspected at least once every 20 years in accordance with WCAP-15666-A. Therefore, in RAI 4.7.1-3, dated December 21, 2007, the staff asked the applicant to discuss: (a) the inspection history, results, method used, area/volume, and coverage; (b) future inspection plans including whether a volumetric inspection will be performed at the end of 40 years or during the extended period of operation, and if not, to discuss how the structural integrity of the flywheel can be ensured; and (c) whether the flywheel surface is painted, and if so, discuss the effectiveness of the surface or visual examination if these inspection methods were used in the past or will be used in the future.

By letter dated January 17, 2008, the applicant responded for part (a) that no recordable indications have been identified from the IP2 and IP3 RCP flywheel inspections. Further, the applicant stated that the RCP motor flywheels at IP2 and IP3 are inspected using the following approved nondestructive examination (NDE) methods.

Volumetric — The ultrasonic examinations performed include a keyway corner examination, a radial gage hole examination, and a periphery examination. In the gage hole examination, the full axial depth of the gage hole is traversed. The examination is performed at each of four gage holes. Additionally, an ultrasonic examination is performed from the periphery of the flywheel scanning toward the bore. Essentially 100 percent of the specified volume coverage is obtained.

Surface — The surface examination performed includes the bore and keyway surfaces of the flywheel using dye penetrant inspection techniques. Essentially 100 percent of the specified surface coverage is obtained.

Visual — The visual examination includes inspection of high-stress areas on all surfaces. Essentially 100 percent of the specified surface coverage is obtained.

With regard to part (b), the applicant stated that, as a result of the staff approval of WCAP-15666, IP2 and IP3 extended the inspection frequency of the RCP flywheel from once every 10 years to once every 20 years. This change occurred in 2004. Entergy will continue to inspect the RCP flywheels as described above at a frequency of at least once every 20 years through the period of extended operation. Based on the evaluations provided in WCAP-15666, which has been approved by the staff, the applicant concluded that the above inspection methods and frequency are sufficient to ensure structural integrity of the RCP flywheels through the period of extended operation. With regard to part (c), the applicant stated that some of the surface areas of the RCP flywheels are painted. However, the areas that are subject to inspection via volumetric, surface, and visual examinations are not painted. Therefore, the applicant concluded that the effectiveness of the NDE examinations performed on the RCP flywheel is not compromised.

The staff finds that the applicant has performed necessary volumetric, surface, and visual examinations of the flywheel at a frequency that was approved by the staff. Therefore, the staff finds that the examination of the flywheel is acceptable.

4.7.1.3 UFSAR Supplement

In RAI 4.7.1-5, dated December 21, 2007, the staff noted that the applicant failed to provide a summary description of its TLAA evaluation of the RCP flywheel in LRA Section A.2.2. By letter dated January 17, 2008, the applicant stated that a TLAA evaluation is not applicable because the RCP flywheel analysis is not a TLAA as defined in 10 CFR 54.3(a). The applicant explained that because the flywheel is not susceptible to stress corrosion cracking and the number of start/stop cycles bound the projected number of cycles for 60 years, the analysis is not a TLAA. As this analysis is not a TLAA, it is not included in LRA, Appendix A.2.2. The staff finds that the RCP flywheel analysis of WCAP-15666 is applicable for 60 years of operation. Therefore, the RCP flywheel should not be considered as a TLAA and a summary description in LRA Section A.2.2 is not required.

4.7.1.4 Conclusion

On the basis of its review, the staff concludes that the RCP flywheel analyses are not TLAAs. The staff also concludes that a summary description of the TLAA evaluation in the UFSAR supplement is not needed because the RCP flywheel is not a TLAA and should not be considered for TLAA evaluation.

4.7.2 Leak before Break

4.7.2.1 Summary of Technical Information in the Application

LRA Section 4.7.2 summarizes the evaluation of LBB for the period of extended operation. LBB analyses evaluate postulated flaw growth in piping and consider the thermal aging of cast austenitic stainless steel piping and fatigue transients that drive flaw growth over the operating life of the plant. Because these two analytic considerations could be influenced by time, LBB analyses are potential TLAAs.

The IP2 structural design protects against the effects of postulated reactor coolant loop pipe ruptures. LBB analyses documented in WCAP-10931, WCAP-10977, and WCAP-10977, Supplement 1, have time-related assumptions that include cast austenitic stainless steel thermal aging and fatigue crack growth analysis.

The IP3 structural design protects against the effects of postulated reactor coolant loop pipe ruptures. LBB analyses documented in WCAP-8228, Appendix A, have time-related assumptions that include cast austenitic stainless steel thermal aging and fatigue crack growth analysis. The following two paragraphs address these assumptions.

The first analytic consideration that could be influenced by time relates to the cast austenitic stainless steel material properties in the pipe fittings. Thermal aging effect increases cast austenitic stainless steel yield strength and decreases its fracture toughness. The decrease is in proportion to the level of ferrite in the material. Thermal aging in these stainless steels continues until it reaches a saturation, or fully aged, point. The analyses used fully-aged toughness values. As the LBB evaluations for both units use saturated (fully-aged) fracture toughness properties, these analyses have no material property time-dependency and are not TLAAs.

The second analytic consideration that could be influenced by time relates to the accumulation of actual fatigue transient cycles. A fatigue crack growth analysis of the RV inlet nozzle to safe-end region determined its sensitivity to small cracks. The analysis is focused on the nozzle to safe-end connection because crack growth calculated at this location represents that of the entire primary loop.

The nozzle to safe-end connection configuration includes an SA-508 Class 2 or Class 3 stainless steel-clad nozzle connected to a stainless steel safe-end by a nickel-based alloy weld. Evaluation of crack growth from fatigue assumed the total allowable numbers of normal, upset, and test transients for the RV.

The calculated fatigue crack growth for 40 years was very small (less than 50 mils) regardless of the material evaluated. As noted in LRA Section 4.3.1, the projections for 60 years of operation indicate that the numbers of significant IP2 or IP3 transients will not exceed design-analyzed values.

4.7.2.2 Staff Evaluation

The staff has approved application of the LBB approach for the main RCS piping at IP2 and IP3 (i.e., hot leg from the RV to the RCPs, the intermediate crossover pipe, and the cold leg from the steam generators to the RV). The LBB approach has not been applied to any other systems or branch lines.

By letter dated February 23, 1989, the staff issued its safety evaluation approving the application of the LBB approach for RCS piping at IP2. The staff's approval was based on the technical basis of (1) WCAP-10977, "Technical Bases for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Indian Point Unit 2," Original—November 1985; Revision 1—March 1986; and Revision 2—December 1986, (2) WCAP-10977, Supplement 1, "Additional Information in Support of the Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Indian Point Unit 2," January 1989, and (3) WCAP-10931, Revision 1, "Toughness Criteria for Thermally Aged Cast Stainless Steel," July 1986.

By letter dated March 10, 1986, the staff approved the application of LBB methods for IP3 primary loop piping based on the submitted Fracture Proof Design Corporation Report 80-121, Revision 1. However, LRA Section 4.7.2 states that IP3 LBB analyses have been documented in the Westinghouse report, WCAP-8228, which was not submitted to the NRC for review. In RAIs 4.7.2-1, 4.7.2-2, and 4.7.2-4, dated December 21, 2007, the staff asked the applicant to confirm whether there are other applicable LBB analyses of record for IP3, and to provide a history and summary description of the analyses, including the parameters that were evaluated and conclusions reached for each analysis. By letter dated January 17, 2008, the applicant explained that between 1981 and 1984 it performed original LBB analyses for the IP3 primary loop piping. These analyses took into account thermal aging effects on cast stainless steel components in the IP3 primary loop. Fracture Proof Design Corporation Report 80-121, Revision 1, documents the results of the 1984 LBB analyses.

The applicant updated its LBB analyses in 1997 in support of the Steam Generator Snubbers Deactivation Program at IP3 and documented the results in WCAP-8228, Revision 1, Appendix A. Subsequently, as part of the stretch power uprate for IP3, the applicant prepared WCAP-16212, including updated LBB analyses, to ensure that the elimination of the primary loop pipe breaks continues to be justified at the uprated operating conditions. WCAP-16212 evaluated the effects of the stretch power uprate on the acceptability of the LBB status of the primary loop piping. WCAP-16212 determined that the LBB conclusions in Fracture Proof Design Corporation Report 80-121 and WCAP-8228, Revision 1, remain valid. As part of its review of the power uprate submittal, the staff concurred with the WCAP-16212 conclusion as shown in SER Section 3.6.6.1 for the IP3 stretch power uprate dated March 24, 2005. That safety evaluation discusses further the impact of power uprate on the LBB analyses.

The potential time-limited assumptions in WCAP-8228, Revision 1, Appendix A, and WCAP-16212 involve the thermal aging of cast austenitic stainless steel and the fatigue crack growth analysis. These two assumptions are addressed below.

<u>Thermal Aging of Cast Austenitic Stainless Steel</u>. The RCS piping material for both IP2 and IP3 is SA 376 Type 316 forged austenitic stainless steel, while the fitting (i.e., elbows) material is SA 351 Type CF8M cast austenitic stainless steel.

The first analysis consideration in WCAP-10977 (for IP2) and WCAP-8228, Appendix A (for IP3), which could be influenced by time is the material properties of cast austenitic stainless steel used in the pipe fittings. Thermal aging causes an elevation in the yield strength of cast austenitic stainless steel and a decrease in fracture toughness due to the level of ferrite in the material. Thermal aging in these stainless steels will continue until a saturation (i.e., fully aged) point is reached. WCAP-10977 and WCAP-8228, Appendix A, address the fracture toughness properties of statically cast CF8M stainless steel. Specifically, fully aged, bounding fracture toughness values were used to conservatively calculate the fracture toughness value (J value) for the cast fittings. The IP3 LBB analysis uses the methodology of NUREG/CR-4513 and WCAP-10931 to determine saturation (fully aged) toughness values. The IP2 LBB analysis uses the methodology of WCAP-10931 to determine saturation (fully aged) toughness values. As the LBB evaluations for both units use saturated (fully aged) fracture toughness properties, these analyses do not have a material property time-dependency and are not considered a TLAA.

The pre-service (normal) and the fully aged fracture toughness values (i.e., J_{Ic}, T_{mat}, and J_{max}) for IP2 were taken from WCAP-10977, Revision 2, as the lower bound values at 600 °F. These IP2 fracture toughness values also bound the IP3 locations evaluated in WCAP-8228, Revision 1.

By letter dated May 19, 2000, Christopher I. Grimes of the NRC forwarded to Douglas J. Walters of the Nuclear Energy Institute an evaluation of thermal aging embrittlement of cast austenitic stainless steel components (ADAMS Accession No. ML003717179). In that letter, the staff provided guidance on how to manage the aging of cast austenitic stainless steel components.

LRA Section 4.7.2 does not mention any AMP to manage the cast austenitic stainless steel components in LBB piping systems. In RAI 4.7.2-5, dated December 21, 2007, the staff asked the applicant to discuss whether the cast austenitic stainless steel components in the LBB piping satisfy the guidance in the staff's May 19, 2000, letter. In its January 17, 2008, letter, the applicant responded that the AMR results for cast austenitic stainless steel components are provided in LRA Section 3. The AMR results for cast austenitic stainless steel components in LRA Section 3 agree with the staff position expressed in the May 19, 2000, letter from Christopher I. Grimes. The applicant stated that the only cast austenitic stainless steel components to which LBB has been applied are pipe fittings (elbows). These fittings will be screened based upon the molybdenum content, casting method, and ferrite content, then inspected as appropriate, in accordance with the Grimes letter. This will be performed under AMP B.1.37, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program." This program is credited in multiple line items in LRA Tables 3.1.2-3 (IP2) and 3.1.2-3 (IP3) and, as described in LRA Section B.1.37, will be consistent with the program described in GALL Report, Section XI.M12.

The description of the program in LRA Appendix B references the Grimes letter of May 19, 2000. The staff has confirmed that LRA Section 3 does identify the thermal aging AMP to manage the cast austenitic stainless steel components and, therefore, this issue is resolved.

In RAIs 4.7.2-3 and 4.7.2-6, dated December 21, 2007, the staff asked whether thermal aging causes an increase in the yield strength of cast austenitic stainless steel. In its January 17, 2008, letter, the applicant further clarified that the yield and ultimate strength used in the LBB analysis for both IP2 and IP3 were taken as the lower bound values because this resulted in the most limiting conditions. The increase in the material yield strength was not credited in the analysis because the lower bound values bound the aged values.

The applicant stated that the mechanical properties and fracture toughness values used in the LBB analyses for both IP2 and IP3 included the most limiting values for both the pre-service and fully aged conditions. Since no additional drop in fracture toughness properties is expected once fully aged conditions are reached, these analyses are time independent and therefore bound the 60 year operating life.

The staff confirmed that the applicant used the mechanical properties and fracture toughness values that bound the 60-year operating life for the cast austenitic stainless steel components in its LBB analysis. The applicant has performed an acceptable TLAA evaluation and therefore this issue is resolved.

Fatigue Crack Growth. In its response to RAI 4.7.2-7, dated January 17, 2008, the applicant stated that the second analysis consideration which could be influenced by time is the accumulation of actual fatigue transient cycles used in WCAP-10977, Revision 2, and Supplement 1, and WCAP-8228, Appendix A. Westinghouse performed a generic fatigue crack growth analysis using the RV inlet nozzle to safe-end region to determine its sensitivity to the presence of small cracks.

The nozzle to safe-end connection was selected because crack growth calculated at this location is representative of the entire primary loop. The nozzle to safe-end connection configuration includes an SA 508 Class 2 or Class 3 stainless steel clad nozzle connected to a stainless steel safe-end by a nickel-based alloy weld (Alloy 82/182). The applicant assumed four initial flaw sizes ranging from 0.292 inches to 0.425 inches and locations with three different materials—stainless steel, SA 508 low-alloy steel, and an Inconel weld cross-section. For IP2 and IP3, the junction of the hot leg and the RV outlet nozzle is the bounding location for load and the fracture toughness associated with thermal aging occur in several pipe fittings. These are joints where the hot leg meets the steam generators and the intermediate crossover leg, and the cold leg meets the RV inlet nozzle.

The applicant used a fatigue crack growth rate law for the stainless steel clad low-alloy steel nozzle from ASME Code, Section XI. Fatigue crack growth rate laws for stainless steel and Alloy 600 in a pressurized-water reactor (PWR) environment were developed based on available industry literature. These crack growth rate laws were applied based on all normal, upset, and test RV fatigue transients, thus resulting in projected rates of crack growth calculated in units of inches/cycle for ferritic steel, stainless steel, and Alloy 600.

The applicant's LBB analyses show that the final crack size for small stable flaws varies by location within the primary coolant system loop piping. For each limiting location the final crack size satisfies LBB acceptance criteria because adequate margin exists between the calculated leak rate and the 1 gallon per minute criterion in RG 1.45, "Guidance in Monitoring and Responding to Reactor Coolant System Leakage." The applicant concluded that there is sufficient margin between detectable leaks and large stable flaws.

In its response to RAI 4.7.2-9, dated January 17, 2008, the applicant stated that the transient conditions and associated number of cycles (for 40 years) used in the fatigue crack growth analysis are the design transients originally defined in the plant's equipment specifications and analyzed in the original component stress reports. USFAR Table 4.1-8, Revision 20, issued in 2006 for IP2, and USFAR Table 4.1-8, Revision 1, issued in 2005 for IP3, list the design transient cycles. The projected numbers of transient cycles for 60 years remain within these analyzed values. LRA Tables 4.3-1 and 4.3-2 include the design transients found in UFSAR Table 4.1-8.

The applicant stated that it did not perform fatigue growth calculations for 60 years because the projected number of cycles for 60 years is less than the numbers of cycles used in the LBB analysis. The 60-year projections for IP2 show that none of the transients that affect the nozzle inlet to safe-end fatigue analysis will exceed the analyzed cycles. The 60-year projections for IP3 show that no transient will exceed the number of analyzed cycles before the end of the period of extended operation. The applicant stated that in WCAP-10977, Table 6.1, and WCAP-8228, Table 8-2, fatigue crack growth at IP2 and IP3 for 40 years was found to be very small based on the projected transients and stress intensity factors, regardless of the material evaluated. The applicant stated that, as a result, there is reasonable assurance that the fatigue crack growth analyses presented in WCAP-10977 (IP2) and WCAP-8228 (IP3), Revision 1, Appendix A, remain valid during the period of extended operation.

The staff has determined that the fatigue crack growth calculation for the RCS piping in the LBB analyses remain valid for the period of extended operation because the 60-year projections for IP2 and IP3 show that no transient will exceed the number of analyzed cycles before the end of the period of extended operation.

Primary Water Stress-Corrosion Cracking. In RAI 4.7.2-8, dated December 21, 2007, the staff noted that PWRs have experienced primary water stress-corrosion cracking (PWSCC) in Alloy 82/182 weld material. The staff questioned how the applicant manages potential PWSCC of Alloy 82/182 weld material in LBB-approved RCS piping. In a letter dated January 17, 2008, as corrected by letter dated November 6, 2008, the applicant identified the following LBB-approved RCS piping components that contain Alloy 82/182 weld material.

Alloy 82/182 Welds in LBB-Approved Piping at Indian Point Unit 2

Weld ID Number	**Piping Identification** **Reactor Vessel Nozzle**	**Pipe Size**
RPVS-21-1A	Primary Coolant Loop 21 (Outlet)	29" I.D.
RPVS-21-14A	Primary Coolant Loop 21 (Inlet)	27½" I.D.
RPVS-22-1A	Primary Coolant Loop 22 (Outlet)	29" 1.D.
RPVS-22-14A	Primary Coolant Loop 22 (Inlet)	27½" I.D.
RPVS-23-1A	Primary Coolant Loop 23 (Outlet)	29" I.D.
RPVS-23-14A	Primary Coolant Loop 23 (Inlet)	27½" I.D.
RPVS-24-1A	Primary Coolant Loop 24 (Outlet)	29" I.D.
RPVS-24-14A	Primary Coolant Loop 24 (Inlet)	27½" I.D.

Alloy 82/182 Welds in LBB-Approved Piping at Indian Point Unit 3

Weld ID Number	Piping Identification Reactor Vessel Nozzle	Pipe Size
INT-1-4100-1(DM)	Primary Coolant Loop 31 (Outlet)	29" 1.D.
INT-1-4100-16(DM)	Primary Coolant Loop 31 (Inlet)	27½" I.D.
INT-1-4200-1(DM)	Primary Coolant Loop 32 (Outlet)	29" I.D.
INT-1-4200-16(DM)	Primary Coolant Loop 32 (Inlet)	27½" I.D.
INT-1-4300-1(DM)	Primary Coolant Loop 33 (Outlet)	29" I.D.
INT-1-4300-16(DM)	Primary Coolant Loop 33 (Inlet)	27½" I.D.
INT-1-4400-1(DM)	Primary Coolant Loop 34 (Outlet)	29" I.D.
INT-1-4400-16(DM)	Primary Coolant Loop 34 (Inlet)	27½" I.D.

The applicant stated that these welds are routinely inspected as part of the ISI Program. The applicant volumetrically inspected the subject welds in IP2 in spring 2006 and in IP3 in fall 1999, with no unacceptable indications. Because the applicant has inspected the subject Alloy 82/182 welds per the ISI Program, the staff's concern in the RAI is resolved.

Impact of Power Uprate on LBB Analyses. By letters dated May 22, 2003, and October 27, 2004 (ADAMS Accession Nos. ML031420375 and ML042960007, respectively), the staff approved measurement uncertainty and stretch power uprate applications for IP2. By letters dated November 26, 2002, and March 24, 2005 (ADAMS Accession Nos. ML023290636 and ML050600380, respectively), the staff approved measurement uncertainty and stretch power uprate applications for IP3. In RAI 4.7.2-10, dated December 21, 2007, the staff asked the applicant whether the results of the 40-year LBB analyses bound the conditions at the end of 60 years, in light of the power uprates. In its January 17, 2008, letter, the applicant responded that the original LBB analyses for IP2 and IP3 will remain valid during the period of extended operation because they are not "40-year analyses," but rather they are analyses based on saturated material properties and numbers of design transients that will not be exceeded in 60 years. WCAP-16156-P, "Indian Point Nuclear Generating Unit No. 2, Stretch Power Uprate NSSS Engineering Report," issued February 2004 for IP2, and WCAP-16211-P, "Power Uprate Project, Indian Point Unit 3 Power Plant, NSSS Engineering Report," issued June 2004 for IP3, address the effects of the power uprate on the original LBB analyses.

The LBB analysis for both IP2 and IP3 used a Westinghouse-proprietary methodology which the staff has previously reviewed and approved. Although the Westinghouse methodology is consistent with the methodology provided in NUREG-1061, Volume 3, these two methodologies are not exactly the same. In some cases, the Westinghouse methodology is more conservative while in other cases, the NUREG-1061, Volume 3, methodology is slightly more conservative. However, both methods provide sufficient margins of safety to ensure that leakage from a crack under normal operating loads would be detected by the existing leak detection systems and that the crack would not result in pipe failure under postulated accident loads.

The staff previously found that the original LBB analyses for IP2 and IP3 are acceptable under the power uprate conditions. The LBB analyses use material properties and transient conditions that satisfy 60 years. Therefore, the LBB analyses are acceptable for use for the extended period of operation.

On LRA page 4.7-2, the applicant asserted that the IP2 and IP3 analyses remain valid during the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i), on the basis of its evaluation of fatigue crack growth and thermal aging of cast austenitic stainless steel. In RAI 4.7.2-11, dated December 21, 2007, the staff asked the applicant to discuss whether the leakage calculations, crack stability, and capability of the reactor coolant leakage detection system in the original LBB analyses will be affected as a result of the extended period of operation. The staff questioned whether there are time-dependency parameters in the LBB calculations other than fatigue crack growth and thermal aging of cast austenitic stainless steel.

In its January 17, 2008, letter, the applicant responded that the leakage calculations for both IP2 and IP3 were based on the operating loads, the material properties, and the through-wall crack length for each of the bounding locations. Since the number of fatigue cycles analyzed bounds the period of extended operation, and since the evaluations used the fully aged fracture toughness values, the bounding flaw size and the material properties also are bounding for 60 years. The normal operating loads are unaffected by the additional 20 years of operation because the operating conditions are not changed for the period of extended operation. Therefore, the leakage calculations performed in support of LBB for 40 years of operation remain valid for the additional 20 years of operation.

The applicant performed crack stability analyses using the most limiting fracture toughness values considering both the pre-service conditions as well as the fully aged conditions. Because no additional drop in fracture toughness properties is expected once fully aged conditions are reached, these analyses are time independent and therefore bound the 60-year operating life.

The leak detection systems for both IP2 and IP3 are based on the following instrumentation—(1) containment air radioactive particulate monitor, (2) containment air radioactive gas monitor (sensitivity variable depending on the amount of fuel clad leakage to provide radioactive gas to the coolant), (3) containment sump monitor, and (4) fan cooler unit condensate flow rate monitor. The applicant stated that the capability of the leak detection system components remains unchanged from that represented in the staff's SERs approving LBB for each unit.

The staff finds that the original LBB analyses for the RCS piping will not be affected by the additional 20 years of operation in terms of leakage calculations, leak detection system capability, and crack stability. Therefore, the LBB analyses are applicable to the extended period of operation.

4.7.2.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of LBB in LRA Sections A.2.2.5 and A.3.2.5 for IP2 and IP3, respectively. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address LBB is adequate and acceptable.

4.7.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that, for LBB, the analyses remain valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.3 Steam Generator Flow-Induced Vibration and Tube Wear

4.7.3.1 Summary of Technical Information in the Application

LRA Section 4.7.3 summarizes the evaluation of steam generator flow-induced vibration and tube wear for the period of extended operation. The IP2 steam generators were evaluated on the basis of flow-induced vibration (tube wear) for the power increase. The analysis of the effects of steam generator flow-induced vibration on tube wear assumed 40 years of operation. The IP2 replacement steam generators went into service in January 2000 and will have less than 40 years of service at the end of the period of extended operation (September 2033); therefore, the analysis of flow-induced vibration effects on tube wear will remain valid through the end of the period of extended operation.

The IP3 steam generators were evaluated as to flow-induced vibration on tube wear for the power increase. The maximum pre-uprate predicted tube wear was 1.3 mils. As a result of the 4.8-percent uprate, tube wear increased 87 percent. The post-uprate wear over 40 years is approximately 2.4 mils (approximately 4.9 percent through-wall wear). This amount of wear will not affect tube integrity significantly. The IP3 replacement steam generators went into service in 1989 and will have 46.5 years of service at the end of the period of extended operation (2035); therefore, this analysis is a TLAA. As tube wear is a result of time in service, it is appropriate to project the additional wear for the period of extended operation as 46.5/40 times the 40-year wear. Projected wear is 2.8 mils (approximately 5.7 percent through-wall) by the end of the period of extended operation, still well below the allowable 40-percent through-wall wear depth (20 mils); hence, tube wear during the period of extended operation will not be unacceptably high, and the IP3 tube wear TLAA has been projected to the end of the period of extended operation.

4.7.3.2 Staff Evaluation

The staff reviewed LRA Section 4.7.3, to verify that, pursuant to 10 CFR 54.21(c)(1)(i), the analyses remain valid for the period of extended operation and that, pursuant to 10 CFR 54.21(c)(1)(ii), the analyses have been projected to the end of the period of extended operation.

The IP2 replacement steam generators were installed in January of 2000. The applicant stated that the design life of the replacement steam generators extends to 2040, which exceeds the period of extended operation sought in its LRA. The applicant concludes that the steam generator flow-induced vibration analysis remains valid for the period of extended operation. In addition to a valid flow-induced vibration analysis, the IP2 steam generators are designed to minimize the potential for flow-induced vibration to occur. Steam generator tubes are supported to minimize excessive vibration which could be detrimental to their structural integrity. The impact of flow-induced vibration will most likely cause tube wear at the intersection of antivibration bars and the tubes. However, periodic inspections conducted in accordance with the applicant's Steam Generator Integrity Program will ensure that any potential tube wear is monitored and detected. On the basis of the information the applicant submitted, the staff concludes that the applicant has demonstrated that, pursuant to 10 CFR 54.21(c)(1)(i), the TLAA of flow-induced vibration on steam generator tubes remain valid for the period of extended operation and is therefore acceptable.

The IP3 replacement steam generators went into service in 1989 and will have 46.5 years of service at the end of the period of extended operation. The licensee projected the additional wear rate for the period of extended operation. The projected wear is well below the allowable wear depth. The staff reviewed and confirmed the licensee's analysis. In addition to a valid flow-induced vibration analysis, the IP3 steam generators are designed to minimize the potential for flow-induced vibration to occur. Steam generator tubes are supported to minimize excessive vibration which could be detrimental to their structural integrity. The impact of flow-induced vibration will most likely cause tube wear at the intersection of antivibration bars and the tubes. However, periodic inspections conducted in accordance with the applicant's Steam Generator Integrity Program will monitor and detect any potential tube wear. On the basis of the information the applicant submitted, the staff concludes that the applicant has demonstrated that, pursuant to 10 CFR 54.21(c)(1)(ii), the TLAA of flow-induced vibration on steam generator tubes has been projected to the end of the period of extended operation and is therefore acceptable.

4.7.3.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of steam generator flow-induced vibration and tube wear in LRA Sections A.2.2.6 and A.3.2.6. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address steam generator flow-induced vibration and tube wear is adequate.

4.7.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that, for IP2, the steam generator flow-induced vibration and tube wear analyses remain valid for the period of extended operation. The applicant also has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for IP3, the analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.8 Conclusion for TLAAs

The staff reviewed the information in LRA Section 4, "Time-Limited Aging Analyses." On the basis of its review, the staff concludes that the applicant has provided a sufficient list of TLAAs, as defined in 10 CFR 54.3, and that the applicant has demonstrated that (1) the TLAAs remain valid for the period of extended operation, as required by 10 CFR 54.21(c)(1)(i), (2) the TLAAs have been projected to the end of the period of extended operation, as required by 10 CFR 54.21(c)(1)(ii), or (3) the effects of aging on intended function(s) will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(c)(1)(iii). The staff also reviewed the UFSAR supplement for the TLAAs and finds that the supplement contains descriptions of the TLAAs sufficient to satisfy the requirements of 10 CFR 54.21(d). In addition, the staff concludes, as required by 10 CFR 54.21(c)(2), that no plant-specific, TLAA-based exemptions are in effect.

With regard to these matters, the staff concludes that reasonable assurance exists that the activities authorized by the renewed licenses will continue to be conducted in accordance with the CLB and that any changes made to the CLB, in order to comply with 10 CFR 54.29(a), are in accordance with the Atomic Energy Act of 1954, as amended, and NRC regulations.

THIS PAGE INTENTIONALLY LEFT BLANK.

SECTION 5

REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

In accordance with Title 10, Part 54, of the *Code of Federal Regulations*, the SER will be referred to the Advisory Committee on Reactor Safeguards (ACRS), which will review the license renewal application (LRA) for Indian Point Nuclear Generating Unit Nos. 2 and 3. The ACRS Subcommittee on Plant License Renewal will conduct its detailed review of the LRA after this safety evaluation report (SER) is issued. Entergy Nuclear Operations, Inc., (the applicant) and the staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff) will meet with the ACRS subcommittee and the ACRS full committee to discuss issues associated with the review of the LRA.

After the ACRS completes its review of the LRA and SER, the full committee will issue a report discussing results of its review. An update to this SER will include the ACRS report and the staff's response to any issues and concerns reported.

THIS PAGE INTENTIONALLY LEFT BLANK.

SECTION 6

CONCLUSION

The staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff) reviewed the license renewal application (LRA) for Indian Point Nuclear Generating Unit Nos. 2 and 3, in accordance with NRC regulations and NUREG-1800, Revision 1, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” dated September 2005. Title 10, Section 54.29, of the *Code of Federal Regulations* (10 CFR 54.29) sets the standards for issuance of a renewed license. Pursuant to 10 CFR 54.29(a), the Commission may issue a renewed license if finds that actions have been identified and have been or will be taken, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis (CLB).

On the basis of its review of the LRA, the staff determines that the requirements of 10 CFR 54.29(a) have been met.

The staff notes that any requirements of 10 CFR Part 51, Subpart A, will be documented in Supplement 38 to NUREG-1437, “Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Indian Point Nuclear Generating Unit Nos. 2 and 3.”

THIS PAGE INTENTIONALLY LEFT BLANK.

APPENDIX A

INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS

During the review of the Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3), license renewal application (LRA) by the staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff), Entergy Nuclear Operations, Inc. (Entergy or the applicant) made commitments related to aging management programs (AMPs) to manage the aging effects for certain structures and components during the period of extended operation. The following table lists these commitments along with the applicant's stated implementation schedules and sources for each commitment.

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
1	Enhance the Above Ground Steel Tanks Program for IP2 and IP3 to perform thickness measurements of the bottom surfaces of the condensate storage tanks, city water tank, and fire water tanks once during the first ten years of the period of extended operation. Enhance the Above Ground Steel Tanks Program for IP2 and IP3 to require trending of thickness measurements when material loss is detected.	A.2.1.1 A.3.1.1 B.1.1	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039
2	Enhance the Bolting Integrity Program for IP2 and IP3 to clarify that actual yield strength is used in selecting materials for low susceptibility to SCC and clarify the prohibition on use of lubricants containing MoS_2 for bolting.	A.2.1.2 A.3.1.2 B.1.2 Audit Items 201, 241, 270	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
3	Implement the Buried Piping and Tanks Inspection Program for IP2 and IP3 as described in LRA Section B.1.6. This new program will be implemented consistent with the corresponding described in NUREG-1801, Section XI.M34, Buried Piping and Tanks Inspection. Include in the Buried Piping and Tanks Inspection Program described in LRA Section B.1.6 a risk assessment of in-scope buried piping and tanks that includes consideration of the impacts of buried piping or tank leakage and of conditions affecting the risk for corrosion. Classify pipe segments and tanks as having a high, medium or low impact of leakage based on the safety class, the hazard posed by fluid contained in the piping and the impact of leakage on reliable plant operation. Determine corrosion risk through consideration of piping or tank material, soil resistivity, drainage, the presence of cathodic protection and the type of coating. Establish inspection priority and frequency for periodic inspections of the in-scope piping and tanks based on the results of the risk assessment. Perform inspections using inspection techniques with demonstrated effectiveness.	A.2.1.5 A.3.1.5 B.1.6 Audit Item 173	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-09-106 NL-09-111

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
4	Enhance the Diesel Fuel Monitoring Program to include cleaning and inspection of the IP2 GT-1 gas turbine fuel oil storage tanks, IP2 and IP3 EDG fuel oil day tanks, IP2 SBO/Appendix R diesel generator fuel oil day tank, and IP3 Appendix R fuel oil storage tank and day tank once every ten years. Enhance the Diesel Fuel Monitoring Program to include quarterly sampling and analysis of the IP2 SBO/Appendix R diesel generator fuel oil day tank, IP2 security diesel fuel oil day tank, and IP3 Appendix R fuel oil storage tank. Particulates, water and sediment checks will be performed on the samples. Filterable solids acceptance criterion will be less than or equal to 10mg/l. Water and sediment acceptance criterion will be less than or equal to 0.05%. Enhance the Diesel Fuel Monitoring Program to include thickness measurement of the bottom surface of the following tanks once every ten years. IP2: EDG fuel oil storage tanks, EDG fuel oil day tanks, SBO/Appendix R diesel generator fuel oil day tank, GT-1 gas turbine fuel oil storage tanks, and diesel fire pump fuel oil storage tank; IP3: EDG fuel oil day tanks, Appendix R fuel oil storage tank, and diesel fire pump fuel oil storage tank. Enhance the Diesel Fuel Monitoring Program to change the analysis for water and particulates to a quarterly frequency for the following tanks. IP2: GT-1 gas turbine fuel oil storage tanks and diesel fire pump fuel oil storage tank; IP3: Appendix R fuel oil day tank and diesel fire pump fuel oil storage tank.	A.2.1.8 A.3.1.8 B.1.9 Audit Items 128, 129, 132, 491, 492, 510	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-057

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
4 (continued)	Enhance the Diesel Fuel Monitoring Program to specify acceptance criteria for thickness measurements of the fuel oil storage tanks within the scope of the program. Enhance the Diesel Fuel Monitoring Program to direct samples be taken and include direction to remove water when detected. Revise applicable procedures to direct sampling of the onsite portable fuel oil contents prior to transferring the contents prior to transferring the contents to storage. Enhance the Diesel Fuel Monitoring Program to direct the addition of chemicals including biocide when the presence of biological activity is confirmed.			
5	Enhance the External Surfaces Monitoring Program for IP2 and IP3 to include periodic inspections of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(3). Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(2).	A.2.1.10 A.3.1.10 B.1.11	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
6	Enhance the Fatigue Monitoring Program for IP2 to monitor steady state cycles and feedwater cycles or perform an evaluation to determine monitoring is not required. Review the number of allowed events and resolve discrepancies between reference documents and monitoring procedures. Enhance the Fatigue Monitoring Program for IP3 to include all the transients identified. Assure all fatigue analysis transients are included with the lowest limiting numbers. Update the number of design transients accumulated to date.	A.2.1.11 A.3.1.11 B.1.12 Audit Item 164	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
7	Enhance the Fire Protection Program to inspect external surfaces of the IP3 RCP oil collection systems for loss of material each refueling cycle. Enhance the Fire Protection Program to explicitly state that the IP2 and IP3 diesel fire pump engine sub-systems (including the fuel supply line) shall be observed while the pump is running. Acceptance criteria will be revised to verify that the diesel engine does not exhibit signs of degradation while running; such as fuel oil, lube oil, coolant, or exhaust gas leakage. Enhance the Fire Protection Program to specify that the IP2 and IP3 diesel fire pump engine carbon steel exhaust components are inspected for evidence of corrosion and cracking at least once each operating cycle. Enhance the Fire Protection Program for IP3 to visually inspect the cable spreading room, 480V switchgear room, and EDG room CO_2 fire suppression system for signs of degradation, such as corrosion and mechanical damage at least once every six months.	A.2.1.12 A.3.1.12 B.1.13	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
8	Enhance the Fire Water Program to include inspection of IP2 and IP3 hose reels for evidence of corrosion. Acceptance criteria will be revised to verify no unacceptable signs of degradation. Enhance the Fire Water Program to inspect a sample of IP2 and IP3 sprinkler heads required for 10 CFR 50.48 using guidance of NFPA 25 (2002 edition), Section 5.3.1.1.1 before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner. Enhance the Fire Water Program to perform wall thickness evaluations of IP2 and IP3 fire protection piping on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion. These inspections will be performed before the end of the current operating term and at intervals thereafter during the period of extended operation. Results of the initial evaluations will be used to determine the appropriate inspection interval to ensure aging effects are identified prior to loss of intended function. Enhance the Fire Water Program to inspect the internal surface of the IP3 foam based fire suppression tanks. Acceptance criteria will be enhanced to verify no significant corrosion.	A.2.1.13 A.3.1.13 B.1.14 Audit Items 105, 106	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-014

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
9	Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to implement comparisons to wear rates identified in WCAP-12866. Include provisions to compare data to the previous performances and perform evaluations regarding change to test frequency and scope. Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to specify the acceptance criteria as outlined in WCAP-12866 or other plant-specific values based on evaluation of previous test results. Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to direct evaluation and performance of corrective actions based on tubes that exceed or are projected to exceed the acceptance criteria. Also stipulate that flux thimble tubes that cannot be inspected over the tube length and cannot be shown by analysis to be satisfactory for continued service, must be removed from service to ensure the integrity of the reactor coolant system pressure boundary.	A.2.1.15 A.3.1.15 B.1.16	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
10	Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to include the following heat exchangers in the scope of the program. • Safety injection pump lube oil heat exchangers • RHR heat exchangers • RHR pump seal coolers • Non-regenerative heat exchangers • Charging pump seal water heat exchangers • Charging pump fluid drive coolers • Instrument air heat exchangers (IP3 only) • Spent fuel pit heat exchangers • Secondary system steam generator sample coolers • Waste gas compressor heat exchangers • SBO/Appendix R diesel jacket water heat exchanger (IP2 only) Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to perform visual inspection on heat exchangers where non-destructive examination, such as eddy current inspection, is not possible due to heat exchanger design limitations. Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to include consideration of material-environment combinations when determining sample population of heat exchangers.	A.2.1.16 A.3.1.16 B.1.17 Audit Item 52	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
10 (continued)	Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to establish minimum tube wall thickness for the new heat exchangers identified in the scope of the program. Establish acceptance criteria for heat exchangers visually inspected to include no unacceptable signs of degradation.			
11	Deleted	Not applicable	Not applicable	NL-09-056
12	Enhance the Masonry Wall Program for IP2 and IP3 to specify that the IP1 intake structure is included in the program.	A.2.1.18 A.3.1.18 B.1.19	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
13	Enhance the Metal-Enclosed Bus Inspection Program to add IP2 480V bus associated with substation A to the scope of the bus inspected. Enhance the Metal-Enclosed Bus Inspection Program for IP2 and IP3 to visually inspect the external surface of metal-enclosed bus enclosure assemblies for loss of material at least once every 10 years. The first inspection will occur prior to the period of extended operation and the acceptance criterion will be no significant loss of material. Enhance the Metal-Enclosed Bus Inspection Program to add acceptance criteria for MEB internal visual inspections to include the absence of indications of dust accumulation on the bus bar, on the insulators, and in the duct, in addition to the absence of indications of moisture intrusion into the duct. Enhance the Metal-Enclosed Bus Inspection Program for IP2 and IP3 to inspect bolted connections at least once every five years if performed visually or at least once every ten years using quantitative measurements. The first inspection will occur prior to the period of extended operation. The plant will process a change to applicable site procedure to remove the reference to "re-torquing" connections for phase bus maintenance and bolted connection maintenance.	A.2.1.19 A.3.1.19 B.1.20 Audit Item 124, 133, 519	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-057

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
14	Implement the Non-EQ Bolted Cable Connections Program for IP2 and IP3 as described in LRA Section B.1.22.	A.2.1.21 A.3.1.21 B.1.22	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039
15	Implement the Non-EQ Inaccessible Medium-Voltage Cable Program for IP2 and IP3 as described in LRA Section B.1.23. This new program will be implemented consistent with the corresponding described in NUREG-1801, Section XI.E3, Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.	A.2.1.22 A.3.1.22 B.1.23 Audit Item 173	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153
16	Implement the Non-EQ Instrumentation Circuits Test Review Program for IP2 and IP3 as described in LRA Section B.1.24. This new program will be implemented consistent with the corresponding described in NUREG-1801, Section XI.E2, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits.	A.2.1.23 A.3.1.23 B.1.24 Audit Item 173	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153
17	Implement the Non-EQ Insulated Cables and Connections Program for IP2 and IP3 as described in LRA Section B.1.25. This new program will be implemented consistent with the corresponding described in NUREG-1801, Section XI.E1, Electrical Cables and Connections Not Subject to 10 CFR 50.39 Environmental Qualification Requirements.	A.2.1.24 A.3.1.24 B.1.25 Audit Item 173	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
18	Enhance the Oil Analysis Program for IP2 to sample and analyze lubricating oil used in the SBO/Appendix R diesel generator consistent with the oil analysis for other site diesel generators. Enhance the Oil Analysis Program for IP2 and IP3 to sample and analyze generator seal oil and turbine hydraulic control oil. Enhance the Oil Analysis Program for IP2 and IP3 to formalize preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria for all components included in the scope of this program. The program will specify corrective actions in the event acceptance criteria are not met. Enhance the Oil Analysis Program for IP2 and IP3 to formalize trending of preliminary oil screening results as well as data provided from independent laboratories.	A.2.1.25 A.3.1.25 B.1.26	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039
19	Implement the One-Time Inspection Program for IP2 and IP3 as described in LRA Section B.1.27. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M32, One-Time Inspection.	A.2.1.26 A.3.1.26 B.1.27 Audit Item 173	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
20	Implement the One-Time Inspection – Small Bore Piping Program for IP2 and IP3 as described in LRA Section B.1.28. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M35, One-Time Inspection of ASME Code Class I Small-Bore Piping.	A.2.1.27 A.3.1.27 B.1.28 Audit Item 173	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153
21	Enhance the Periodic Surveillance and Preventive Maintenance Program for IP2 and IP3 as necessary to assure that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of operation.	A.2.1.28 A.3.1.28 B.1.29	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039
22	Enhance the Reactor Vessel Surveillance Program for IP2 and IP3 revising the specimen capsule withdrawal schedules to draw and test a standby capsule to cover the peak reactor vessel fluence expected through the end of the period of extended operation. Enhance the Reactor Vessel Surveillance Program for IP2 and IP3 to require that tested and untested specimens from all capsules pulled from the reactor vessel are maintained in storage.	A.2.1.31 A.3.1.31 B.1.32	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
23	Implement the Selective Leaching Program for IP2 and IP3 as described in LRA Section B.1.33. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M33, Selective Leaching of Materials.	A.2.1.32 A.3.1.32 B.1.33 Audit Item 173	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153
24	Enhance the Steam Generator Integrity Program for IP2 and IP3 to require that the results of the condition monitoring assessment are compared to the operational assessment performed for the prior operating cycle with differences evaluated.	A.2.1.34 A.3.1.34 B.1.35	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
25	Enhance the Structures Monitoring Program to explicitly specify that the following structures are included in the program. • Appendix R diesel generator foundation (IP3) • Appendix R diesel generator fuel oil tank vault (IP3) • Appendix R diesel generator switchgear and enclosure (IP3) • city water storage tank foundation • condensate storage tanks foundation (IP3) • containment access facility and annex (IP3) • discharge canal (IP2/3) • emergency lighting poles and foundations (IP2/3) • fire pumphouse (IP2) • fire protection pumphouse (IP3) • fire water storage tank foundations (IP2/3) • gas turbine 1 fuel storage tank foundation • maintenance and outage building-elevated passageway (IP2) • new station security building (IP2) • nuclear service building (IP1) • primary water storage tank foundation (IP3) • refueling water storage tank foundation (IP3) • security access and office building (IP3) • service water pipe chase (IP2/3) • service water valve pit (IP3) • superheater stack • transformer/switchyard support structures (IP2) • waste holdup tank pits (IP2/3)	A.2.1.35 A.3.1.35 B.1.36 Audit Items 86, 87, 88, 417, 358, 360	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-057 NL-08-127

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
25 (continued)	Enhance the Structures Monitoring Program for IP2 and IP3 to clarify that in addition to structural steel and concrete, the following commodities (including their anchorages) are inspected for each structure as applicable. • cable trays and supports • concrete portion of reactor vessel supports • conduits and supports • cranes, rails and girders • equipment pads and foundations • fire proofing (pyrocrete) • HVAC duct supports • jib cranes • manholes and duct banks • manways, hatches and hatch covers • monorails • new fuel storage racks • sumps, sump screens, strainers and flow barriers Enhance the Structures Monitoring Program for IP2 and IP3 to inspect inaccessible concrete areas that are exposed by excavation for any reason. IP2 and IP3 will also inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring.			

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
25 (continued)	Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspections of elastomers (seals, gaskets, seismic joint filler, and roof elastomers) to identify cracking and change in material properties and for inspection of aluminum vents and louvers to identify loss of material. Enhance the Structures Monitoring Program for IP2 and IP3 to perform an engineering evaluation of groundwater samples to assess aggressiveness of groundwater to concrete on a periodic basis (at least once every five years). IPEC will obtain samples from at least 5 wells that are representative of the ground water surrounding below-grade site structures and perform an engineering evaluation of the results from those samples for sulfates, pH and chlorides. Additionally, to assess potential indications of spent fuel pool leakage, IPEC will sample for tritium in groundwater wells in close proximity to the IP2 spent fuel pool at least once every 3 months. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspection of normally submerged concrete portions of the intake structures at least once every 5 years. Inspect the baffling/grating partition and support platform of the IP3 intake structure at least once every 5 years. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspection of the degraded areas of the water control structure once per 3 years rather than the normal frequency of once per 5 years during the PEO.			

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
26	Implement the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.37. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	A.2.1.36 A.3.1.36 B.1.37 Audit Item 173	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153
27	Implement the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.38. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M13, Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	A.2.1.37 A.3.1.37 B.1.38 Audit Item 173	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153
28	Enhance the Water Chemistry Control – Closed Cooling Water Program to maintain water chemistry of the IP2 SBO/Appendix R diesel generator cooling system per EPRI guidelines. Enhance the Water Chemistry Control – Closed Cooling Water Program to maintain the IP2 and IP3 security generator and fire protection diesel cooling water pH and glycol within limits specified by EPRI guidelines.	A.2.1.39 A.3.1.39 B.1.40 Audit Item 509	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-08-057
29	Enhance the Water Chemistry Control – Primary and Secondary Program for IP2 to test sulfates monthly in the RWST with a limit of <150 ppb.	A.2.1.40 B.1.41	IP2: September 28, 2013	NL-07-039

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
30	For aging management of the reactor vessel internals, IPEC will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.	A.2.1.41 A.3.1.41 B.1.41	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039
31	Additional P-T curves will be submitted as required per 10 CFR 50, Appendix G prior to the period of extended operation as part of the Reactor Vessel Surveillance Program.	A.2.2.1.2 A.3.2.1.2 4.2.3	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039
32	As required by 10 CFR 50.61(b)4), IP3 will submit a plant-specific safety analysis for plate B2803-3 to the NRC three years prior to reaching the RT_{PTS} screening criterion. Alternatively, the site may choose to implement the revised PTS rule when approved.	A.3.2.1.4 4.2.5	IP3: December 12, 2015	NL-07-039 NL-08-127

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
33	At least 2 years prior to entering the period of extended operation, for the locations identified in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3), under the Fatigue Monitoring Program, IP2 and IP3 will implement one or more of the following: (1) Consistent with the Fatigue Monitoring Program, Detection of Aging Effects, update the fatigue usage calculations using refined fatigue analyses to determine valid CUFs less than 1.0 when accounting for the effects of reactor water environment. This includes applying the appropriate Fen factors to valid CUFs determined in accordance with one of the following: 1. For locations in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3), with existing fatigue analysis valid for the period of extended operation, use the existing CUF. 2. Additional plant-specific locations with a valid CUF may be evaluated. In particular, the pressurizer lower shell will be reviewed to ensure the surge nozzle remains the limiting component. 3. Representative CUF values from other plants, adjusted to or enveloping the IPEC plant specific external loads may be used if demonstrated applicable to IPEC. 4. An analysis using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case) may be performed to determine a valid CUF.	A.2.2.3.3 A.3.2.2.3 4.3.3 Audit Item 146	IP2: September 28, 2011 IP3: December 12, 2013	NL-07-039 NL-07-153 NL-08-021

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
33 (continued)	(2) Consistent with the Fatigue Monitoring Program, Corrective Actions, repair or replace the affected locations before exceeding a CUF of 1.0.			
34	IP2 SBO/Appendix R diesel generator will be installed and operational by April 30, 2008. This committed change to the facility meets the requirements of 10 CFR 50.59(c)(1) and, therefore, a license amendment pursuant to 10 CFR 50.90 is not required.	2.1.1.3.5	April 30, 2008 Complete	NL-07-078 NL-08-074
35	Perform a one-time inspection of representative sample area of IP2 containment liner affected by the 1973 event behind the insulation, prior to entering the period of extended operation, to assure liner degradation is not occurring in this area. Perform a one-time inspection of representative sample area of the IP3 containment steel liner at the juncture with the concrete floor slab, prior to entering the period of extended operation, to assure liner degradation is not occurring in this area.	Audit Item 27	IP2: September 28, 2013 IP3: December 12, 2015	NL-08-127 NL-09-018
36	Perform a one-time inspection and evaluation of a sample of potentially affected IP2 refueling cavity concrete prior to the period of extended operation. The sample will be obtained by core boring the refueling cavity wall in an area that is susceptible to exposure to borated water leakage. The inspection will include an assessment of embedded reinforcing steel.	Audit Item 359	IP2: September 28, 2013	NL-08-127 NL-09-056 NL-09-079

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
37	Enhance the Containment Inservice Inspection (CII-IWL) Program to include inspections of the containment using enhanced characterization of degradation (i.e., quantifying the dimensions of noted indications through the use of optical aids) during the period of extended operation. The enhancement includes obtaining critical dimensional data of degradation where possible through direct measurement or the use of scaling technologies for photographs, and the use of consistent vantage points for visual inspections.	Audit Item 361	IP2: September 28, 2013 IP3: December 12, 2015	NL-08-127
38	For Reactor Vessel Fluence, should future core loading patterns invalidate the basis for the projected values of RT_{PTS} or $C_V USE$, updated calculations will be provided to the NRC.	4.2.1	IP2: September 28, 2013 IP3: December 12, 2015	NL-08-143
39	Deleted		Not applicable	NL-09-079

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
40	Evaluate plant specific and appropriate industry operating experience and incorporate lessons learned in establishing appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs. Documentation of the operating experience evaluated for each new program will be available on site for NRC review prior to the period of extended operation.	B.1.6 B.1.22 B.1.23 B.1.24 B.1.25 B.1.27 B.1.28 B.1.33 B.1.37 B.1.38	IP2: September 28, 2013 IP3: December 12, 2015	NL-09-106

THIS PAGE INTENTIONALLY LEFT BLANK.

APPENDIX B

CHRONOLOGY

This appendix lists chronologically the licensing correspondence between the staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff) and Entergy Nuclear Operations, Inc. (Entergy or the applicant). This appendix also lists other correspondence concerning the staff's review of the Indian Point Nuclear Generating Unit Nos. 2 and 3 license renewal application (LRA) (Docket Nos. 50-247 and 50-286).

APPENDIX B: CHRONOLOGY	
Date	**Subject**
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application (ADAMS Accession No. ML071210512)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3 - License Renewal Application Boundary Drawings (ADAMS Accession No. ML071210112)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Cover. (ADAMS Accession No. ML071210516)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Page i, Preface through Chapter 4.0, Page 4.7-4. (ADAMS Accession No. ML071210517)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix A, Updated Final Safety Analysis Report Supplement (ADAMS Accession No. ML071210520)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix B, Aging Management Programs and Activities (ADAMS Accession No. ML071210523)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix C (ADAMS Accession No. ML071210524)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix D, Technical Specification Changes (ADAMS Accession No. ML071210527)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix E, Applicant's Environment Report (ADAMS Accession No. ML071210530)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application.

APPENDIX B: CHRONOLOGY	
Date	**Subject**
	Attachment A, Threatened and Endangered Species Correspondence (ADAMS Accession No. ML071210553)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Attachment B, Historical and Archeological Properties Correspondence (ADAMS Accession No. ML071210558)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Attachment C, Clean Water Act Documentation (ADAMS Accession No. ML071210560)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Attachment D, Coastal Management Program Consistency Determination (ADAMS Accession No. ML071210562)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix E List of Section 2 Figures (ADAMS Accession No. ML071210565)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix E Figure 2-1 through Figure 2-6 (ADAMS Accession No. ML071210567)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix E Figure 2-7 through Figure 2-12 (ADAMS Accession No. ML071210569)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix E Figure 2-13 through Figure 2-17 (ADAMS Accession No. ML071210570)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix E Figure 2-18 through Figure 2-23 (ADAMS Accession No. ML071210572)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix E Figure 2-24 through Figure 2-29 (ADAMS Accession No. ML071210574)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application Environmental Report References (ADAMS Accession No. ML071210108)
05/03/2007	Indian Point Nuclear Generating Units 2 and 3 - Supplement to License Renewal Application (ADAMS Accession No. ML071280700)
05/07/2007	Federal Register Notice, Receipt and Availability of the License Renewal Application for the Indian Point Nuclear Generating Unit Nos. 2 and 3 (ADAMS

APPENDIX B: CHRONOLOGY	
Date	**Subject**
	Accession No. ML071080133)
05/31/2007	Meeting Notice, Forthcoming Meeting to Discuss the License Renewal Review Process for Indian Point Nuclear Generating Unit Nos. 2 and 3 License Renewal Application (LRA) (ADAMS Accession No. ML071450442)
06/13/2007	Press Release-I-07-034 - NRC to Discuss Process for Review of License Renewal Application for Indian Point (ADAMS Accession No. ML071640225)
06/18/2007	Letter from NRC to Entergy Nuclear Operations, Inc, Review Status of the License Renewal Application (LRA) for the Indian Point Nuclear Generating Unit Nos. 2 and 3 (ADAMS Accession No. ML071630049)
06/21/2007	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Unit 2, Station Blackout (SBO) / Appendix R Diesel Generator Commitment, Response to NRC Review Status of License Renewal Application (ADAMS Accession No. ML071800318)
07/10/2007	Conference Call Summary Regarding Status of Acceptance Review for the Indian Point Nuclear Generating Unit Nos. 2 and 3 License Renewal Application (ADAMS Accession No. ML071690181)
07/25/2007	Federal Register Notice, Determination of Acceptability and Sufficiency for Docketing, Proposed Review Schedule, and Opportunity for a Hearing Regarding the Application from ENO, Inc. For Renewal of the Operating License for the Indian Point Nuclear Generating Unit Nos. 2 and 3 (ADAMS Accession No. ML071900365)
07/25/2007	Press Release-07-091 - NRC Announces Opportunity to Request Hearing on Application to Renew Operating License for Indian Point Nuclear Power Plant (ADAMS Accession No. ML072060515)
08/06/2007	Federal Register Notice, Notice of Intent to Prepare an Environmental Impact Statement and Conduct Scoping Process for License Renewal for the Indian Point Nuclear Generating Units 2 and 3 (TAC MD5411 and MD 5412) (ADAMS Accession No. ML071840939)
08/20/2007	Letter from NRC to Entergy Nuclear Operations, Inc., Summary of Public Meetings Related to the License Renewal Process for the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application (ADAMS Accession No. ML072180136)
09/11/2007	Press Release-I-07-046 - NRC to Solicit Public Comments on Sept. 19 as Part of Indian Point License Renewal Application Review (ADAMS Accession No. ML072540791)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
09/27/2007	Audit and Review Plan for Plant Aging Management Review and Programs for the Indian Point Units 2 and 3 (ADAMS Accession No. ML072290180)
10/11/2007	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3 - Supplement to License Renewal Application (LRA) (ADAMS Accession No. ML072910276)
10/16/2007	09/21/2007 Summary of Telephone Conference Call Held Between the U.S. Nuclear Regulatory Commission and Entergy Nuclear Operations, Inc., Concerning Draft Requests for Additional Information (ADAMS Accession No. ML072770605)
10/16/2007	10/02/2007 Summary of Telephone Conference Call Held Between the U.S. Nuclear Regulatory Commission and Entergy Nuclear Operations, Inc., Concerning Requests for Additional Information (ADAMS Accession No. ML072780439)
10/24/2007	Letter from NRC to Entergy Nuclear Operations, Inc, Requests for Additional Information for the Review of the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application (ADAMS Accession No. ML072920027)
10/29/2007	Letter from NRC to Entergy Nuclear Operations, Inc., Request for Additional Information for the Review of the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application (ADAMS Accession No. ML072920229)
11/09/2007	Letter from NRC to Entergy Nuclear Operations, Inc., Request for Additional Information for the Review of the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application (ADAMS Accession No. ML073060401)
11/16/2007	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3 - Reply to Request for Additional Information Regarding License Renewal Application (ADAMS Accession No. ML073320225)
11/19/2007	10/11/2007 Summary of Telephone Conference Call Between the NRC and Entergy Concerning D-RAIs Pertaining to the Indian Point LRA (ADAMS Accession No. ML073170649)
11/21/2007	11/01/2007 Summary of Telephone Conference Call Between the NRC and Entergy Concerning Draft Requests for Additional Information Pertaining to the Indian Point Nuclear Generating Units 2 and 3, LRA (ADAMS Accession No. ML073110364)
11/28/2007	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3 - Reply to Request for Additional Information

APPENDIX B: CHRONOLOGY	
Date	**Subject**
	Regarding License Renewal Application (ADAMS Accession No. ML073460037)
12/06/2007	Letter from Entergy Nuclear Operations, Inc., to NRC, Reply to Request for Additional Information, Regarding License Renewal Application (ADAMS Accession No. ML073470241)
12/07/2007	11/15/2007 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning Draft Requests for Additional Information Pertaining to the Indian Point Nuclear Generating Units 2 and 3 (ADAMS Accession No. ML073250152)
12/07/2007	11/13/2007 Summary of Telephone Conference Call Between NRC and Entergy Nuclear Operations, Inc., Concerning Draft Requests for Additional Information Pertaining to Indian Point (ADAMS Accession No. ML073190360)
12/07/2007	Letter from NRC to Entergy Nuclear Operations, Inc., Request for Additional Information for the Review of the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application (ADAMS Accession No. ML073190401)
12/07/2007	Letter from NRC to Entergy Nuclear Operations, Inc., Request for Additional Information for the Review of the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application (ADAMS Accession No. ML073250226)
12/18/2007	12/04/2007 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning Draft RAI Pertaining to the Indian Point Nuclear Generating Units 2 and 3, LRA-Reactor Coolant Pump Flywheel and Leak Before Break Analyses (ADAMS Accession No. ML073460905)
12/18/2007	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3, Amendment 1 to License Renewal Application (ADAMS Accession No. ML073650195)
12/18/2007	12/03/2007 Summary of Telephone Conference Call Between NRC and Entergy Nuclear Operations, Inc., Concerning Requests for Additional Information Pertaining to Indian Point Nuclear Generating Units 2 and 3 (ADAMS Accession No. ML073450399)
12/20/2007	12/04/2007 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning RAIs Pertaining to the Indian Point Nuclear Generating Units 2 and 3, LRA - Reactor Vessel Surveillance and Neutron Embrittlement (ADAMS Accession No. ML073450327)
12/20/2007	12/04/2007 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning RAIs Pertaining to Indian Point

APPENDIX B: CHRONOLOGY	
Date	**Subject**
	Nuclear Generating Units 2 and 3, LRA - Station Blackout Recovery (ADAMS Accession No. ML073450261)
12/21/2007	Letter from NRC to Entergy Nuclear Operations, Inc., Requests for Additional Information for the Review of Indian Point Nuclear Generating Units 2 and 3, LRA - Reactor Coolant Pump Flywheel and Leak Break Analysis (ADAMS Accession No. ML073460141)
01/04/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3 - Reply to Request for Additional Information, Regarding License Renewal Application (Steam Generator Tube Integrity and Chemistry) (ADAMS Accession No. ML080160123)
01/04/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3 - Reply to Request for Additional Information Regarding License Renewal Application-(Balance of Plant Systems) (ADAMS Accession No. ML080160284)
01/14/2008	Letter from NRC to Entergy Nuclear Operations, Inc., Request for Additional Information for the Review of the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Scoping and Screening Methodology (ADAMS Accession No. ML080100645)
01/17/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Reply to Request for Additional Information Regarding License Renewal Application - (Reactor Coolant Pump Flywheel and Leak Before Break Analyses) (ADAMS Accession No. ML080250026)
01/17/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3 - Clarifications to Reactor Vessel Surveillance Program and Neutron Embrittlement Time-Limited Aging Analyses and Audit Item #105; and Revision to License Renewal Regulatory Commitment List (ADAMS Accession No. ML080250027)
01/22/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3, License Renewal Application Amendment 2 (ADAMS Accession No. ML080290659)
01/22/2008	01/09/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning Draft RAI Pertaining to Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Reactor Coolant System (ADAMS Accession No. ML080180420)
01/24/2008	01/09/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning Draft Request for Additional Information Pertaining to the Indian Point Nuclear Generating Unit (ADAMS

APPENDIX B: CHRONOLOGY	
Date	**Subject**
	Accession No. ML080220466)
01/24/2008	Letter from NRC to Entergy Nuclear Operations, Inc., Revision of Schedule for the Conduct of Review of the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application (ADAMS Accession No. ML080230115)
01/28/2008	01/22/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning the Indian Point Nuclear Generating Units 2 and 3, LRA - Metal Fatigue (ADAMS Accession No. ML080230370)
01/28/2008	Letter from NRC to Entergy Nuclear Operations, Inc., Request for Additional Information for the Review of the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Reactor Coolant System and Structures (ADAMS Accession No. ML080220099)
02/13/2008	02/07/2008 Summary of Telephone Conference Call Between NRC and Entergy Nuclear Operations, Inc., Concerning Responses to Request for Additional Information Pertaining to Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Containment Coatings (ADAMS Accession No. ML080420430)
02/13/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3, Reply to Request for Additional Information Regarding License Renewal Application - Scoping and Screening Methodology (ADAMS Accession No. ML080510579)
02/13/2008	Letter from NRC to Entergy Nuclear Operations, Inc., Request for Additional Information for the Review of the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Balance of Plant, Fire Protection and Nickel Alloy (ADAMS Accession No. ML080380429)
02/27/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3, Reply to Request for Additional Information Regarding License Renewal Application - Reactor Coolant System and Structures (ADAMS Accession No. ML080640843)
03/10/2008	02/08/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning Response to Audit Item Related to the Indian Point Nuclear Generation Unit Nos. 2 and 3 (ADAMS Accession No. ML080420629)
03/12/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3, Reply to Request for Additional Information Regarding License Renewal Application - Balance of Plant, Fire Protection,

APPENDIX B: CHRONOLOGY	
Date	**Subject**
	and Nickel Alloy (ADAMS Accession No. ML080780438)
03/24/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3 - Amendment 3 to License Renewal Application (ADAMS Accession No. ML081070255)
04/02/2008	03/07/2008 - Summary of Telephone Conference Call Between NRC and Entergy Nuclear Operations, Inc., Concerning Responses to Request for Additional Information Related to the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application (ADAMS Accession No. ML080840568)
04/03/2008	03/18/2008 Summary of Telephone Conference Call Between NRC and Entergy Nuclear Operations, Inc., Concerning Response to Audit Item Related to the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application (ADAMS Accession No. ML080850050)
04/09/2008	02/12/2008 Summary of Telephone Conference Call Between NRC and Entergy Nuclear Operations, Inc., Concerning Request for Additional Information Related to the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application Leak Before Break Analyses (ADAMS Accession No. ML080800437)
04/18/2008	Letter from NRC to Entergy Nuclear Operations, Inc., Request for Additional Information, Review of License Renewal Application - Time-Limited Aging Analyses, Bolted Connections, and Boraflex (ADAMS Accession No. ML080870374)
04/23/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3 - Reply to Request for Additional Information Regarding Site Audit Review of License Renewal Application (ADAMS Accession No. ML081230243)
04/23/2008	Letter from NRC to Entergy Nuclear Operations, Inc., Revision of Schedule for the Review of the Indian Point Nuclear Generating Units 2 and 3 License Renewal Application (ADAMS Accession No. ML081000441)
04/29/2008	Letter from NRC to Entergy Nuclear Operations, Inc., Request for Additional Information for the Review of the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Metal Enclosed Buses and Fire Protection (ADAMS Accession No. ML081150435)
04/30/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3, Amendment 4 to License Renewal Application (ADAMS Accession No. ML081280491)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
05/07/2008	Letter from NRC to Entergy Nuclear Operations, Inc., Request for Additional Information for Review of Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Operating Experience (ADAMS Accession No. ML081230082)
05/08/2008	04/14/2008 Summary of Telephone Conference Call Between NRC and Entergy Nuclear Operations, Inc., Concerning Response to Audit Items Related to Indian Point Nuclear Generating Units 2 and 3, License Renewal Application- Submerged Cables (ADAMS Accession No. ML081280586)
05/08/2008	04/3/2008 Summary of Telephone Conference Call Between NRC and Entergy Nuclear Operations, Inc., Concerning Responses to Request for Additional Information Related to the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Metal Fatigue (ADAMS Accession No. ML081190059)
05/08/2008	Summary of Telephone Conference Calls Held on 4/16 and 4/28/08 Between NRC and Entergy Concerning Responses to RAI Related to Indian Point Nuclear Generating Units 2 and 3 (ADAMS Accession No. ML081160391)
05/12/2008	Letter from NRC to Entergy Nuclear Operations, Inc., Request for Additional Information for Review of Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Structures (ADAMS Accession No. ML081230347)
05/12/2008	04/28/2008 Summary of Telephone Conference Call Between NRC and Entergy Nuclear Operations, Inc., Concerning Responses to Request for Additional Information Related to the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application – Operating Experience (ADAMS Accession No. ML081260345)
05/16/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3, Reply to Request for Additional Information Regarding License Renewal Application Time-Limited Aging Analyses and Boraflex (ADAMS Accession No. ML081490317)
05/23/2008	05/07/2008 Summary of Telephone Conference Between NRC and Entergy Nuclear Operations, Inc., Related to the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application - Status of Open Items (ADAMS Accession No. ML081400821)
05/28/2008	Letter from NRC to Entergy Nuclear Operations, Inc., Request For Additional Information for the Review of the Indian Point Nuclear Generating Units 2 And 3, License Renewal Application - Inaccessible of Underground Cables (ADAMS Accession No. ML081480201)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
06/05/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3, Reply to Request for Additional Information Regarding License Renewal Application - Operating Experience (ADAMS Accession No. ML081630202)
06/11/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point, Units 2 & 3, Reply to Request for Additional Information Regarding License Renewal Application Structures - Clarification on Responses (ADAMS Accession No. ML081760264)
06/11/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating, Units 2 and 3 - Amendment 5 to License Renewal Application (ADAMS Accession No. ML081760265)
06/11/2008	Press Release-I-08-040: NRC to Discuss Preliminary Results of Inspection for Indian Point License Renewal Application on June 18 (ADAMS Accession No. ML081630147)
06/27/2008	05/19/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Submerged Cables (ADAMS Accession No. ML081770331)
06/27/2008	05/30/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning Responses to Request for Additional Information Related to the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application (ADAMS Accession No. ML081720557)
07/09/2008	06/02/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning Response to Audit Item Related to the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Bolted Connections (ADAMS Accession No. ML081770527)
07/25/2008	07/08/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Related to the Indian Point, Unit 2 & 3, License Renewal Application Concerning Reactor Vessel Neutron Embrittlement & Submerged Cables (ADAMS Accession No. ML082050612)
07/29/2008	06/24/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Related to the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Balance of Plant (ADAMS Accession No. ML082050276)
08/01/2008	Letter from NRC to Entergy Nuclear Operations, Inc., Inspection Report IR 05000247-08-006 and 05000286-08-006 on 01/28/20080 - 02/01,11-14/08,

APPENDIX B: CHRONOLOGY	
Date	**Subject**
	03/31/ - 04/02/08, 6/02-06, 18/08 for Indian Point, Units 2 and 3 (ADAMS Accession No. ML082140149)
08/14/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, "Indian Point, Units 2 and 3 - Additional Information re License Renewal Application - Structural OE Clarifications, Clarifications for Electrical RAIs and Audit Questions, License Renewal Application Amendment" (ADAMS Accession No. ML082350071)
09/02/2008	Letter NRC to Entergy Nuclear Operations, Inc, "Revision of Schedule for the Conduct of Review of the Indian Point Nuclear Generating, Units 2 & 3, License Renewal Application" (ADAMS Accession No. ML082400214)
09/02/2008	Press Release-08-160: NRC Extends Review Schedule for Indian Point License Renewal Application" (ADAMS Accession No. ML082460633)
09/24/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, "Indian Point Units 2 & 3, Additional Information Regarding License Renewal Application - Reactor Vessel Fluence Clarification" (ADAMS Accession No. ML082760402)
10/24/2008	09/08/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning Additional Information Related to the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application—Operating Experience And LRA Section 3.5.2.2 (ADAMS Accession No. ML082950776)
10/28/2008	09/15/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Pertaining to the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application – Reactor Vessel Neutron Embrittlement (ADAMS Accession No. ML082970810)
11/06/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, "Additional Information Regarding License Renewal Application - Operating Experience Clarification" (ADAMS Accession No. ML083220425)
12/22/2008	Letter from NRC to Entergy Nuclear Operations, Inc., regarding Notice Of Availability of the Draft Supplement 38 to the Generic Environmental Impact Statement For License Renewal of Nuclear Plants Regarding Indian Point Nuclear Generating Unit Nos. 2 and 3 (ADAMS Accession No. ML083390523)
12/30/2008	Letter from NRC to Entergy Nuclear Operations, Inc., regarding Request for Additional Information for the Review of the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application – Miscellaneous Items (ADAMS Accession No. ML083640270)
01/13/2009	Letter from NRC to Entergy Nuclear Operations, Inc., "Audit Reports regarding the License Renewal Application for the Indian Point Units 2 and 3, License

APPENDIX B: CHRONOLOGY	
Date	**Subject**
	Renewal Application" (ADAMS Accession No. ML083540625)
01/13/2009	"Scoping and Screening Methodolgy Audit Trip Report For Indian Point, Units 2 and 3" (ADAMS Accession No. ML083540648)
01/13/2009	"Audit Report For Plant Aging Management Programs and Reviews for Indian Point, Units 2 and 3" (ADAMS Accession No. ML083540662)
01/15/2009	Letter from NRC to Entergy Nuclear Operations, Inc., "Safety Evaluation Report with Open Items Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3" (ADAMS Accession No. ML090060045)
01/15/2009	"Safety Evaluation Report with Open Items Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3" (ADAMS Accession No. ML090150571)
01/16/2009	Press Release 09-012: NRC Issues Safety Evaluation Report with Open Items for Indian Point Nuclear Plant License Renewal Application (ADAMS Accession No. ML090160217)
02/04/2009	12/17/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning Draft Request for Additional Information Pertaining to the Indian Point Nuclear Generating Unit Nos. 2 and 3, LRA-Open Items (ADAMS Accession No. ML090300033)
01/27/2009	Letter from Entergy Nuclear Operations, Inc., to NRC, “Indian Point, Units 2 & 3, Reply to Request for Additional Information - Miscellaneous Items” (ADAMS Accession No. ML090420455)
03/13/2009	Summary of Telephone Conference Calls Held Between February 9 and 17, 2009, between NRC and Entergy Nuclear Operations, Inc., Concerning Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application-Status of Open Items (ADAMS Accession No. ML090710320)
03/25/2009	03/02/2009 Summary of Telephone Conference Call Held Between NRC and Entergy Nuclear Operations, Inc., Concerning Draft Request for Additional Information Pertaining to the Indian Point, Units 2 & 3, License Renewal Application - Open Items (ADAMS Accession No. ML090760748)
03/12/2009	Letter from Entergy Nuclear Operations, Inc., to NRC, “Indian Point Nuclear Generating Units 2 and 3 - Response to Safety Evaluation Report with Open Items Related to the License Renewal” (ADAMS Accession No. ML090830518)
03/04/2009	“Transcript of the ACRS Plant License Renewal Subcommittee Meeting (Indian Point), March 04, 2009” (ADAMS Accession No. ML090840402)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
04/03/2009	Letter from NRC to Entergy Nuclear Operations, Inc., “Request for Additional Information for the Review of the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application - Open Items” (ADAMS Accession No. ML090920150)
04/09/2009	04/01/09 Summary of Telephone Conference Call Between the U.S. Nuclear Regulatory Commission and Entergy Nuclear Operations, Inc., Concerning Draft Request for Additional Information Pertaining to the Indian Point Nuclear Generating Units 2 and 3 License Renewal Application – Open Items" (ADAMS Accession No. ML090930495)
05/06/2009	“Certified Minutes of the Plant License Renewal Subcommittee Regarding Indian Point Nuclear Generating Units 2 and 3 on March 4, 2009” (ADAMS Accession No. ML091260359)
05/01/2009	Letter from Entergy Nuclear Operations, Inc., to NRC, “Indian Point, Units 2 & 3, Reply to Request for Additional Information - Open Items” (ADAMS Accession No. ML091320338)
06/10/2009	04/27/09 Summary of Telephone Conference Call Held Between the NRC and Entergy Nuclear Operations, Inc., Concerning RAIs Pertaining to the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal - Open Items (ADAMS Accession No. ML091350334)
05/20/2009	Letter from NRC to Entergy Nuclear Operations, Inc., “Indian Point Nuclear Generating Unit Nos. 2 and 3, RAI for the Review of License Renewal Application” (ADAMS Accession No. ML091380185)
06/04/2009	“ACRS Meeting with the U.S. Nuclear Regulatory Commission, - June 4, 2009, Slides” (ADAMS Accession No. ML091390631)
05/15/2009	Letter from Entergy Nuclear Operations, Inc., to NRC, “Indian Point, Units 2 & 3 – Amendment 8 to License Renewal Application” (ADAMS Accession No. ML091460051)
06/12/2009	Letter from Entergy Nuclear Operations, Inc., to NRC, “Indian Point Nuclear Generating, Units 2 & 3 - Reply to Request for Additional Information Regarding Offsite Power, Refueling Cavity, and Unit 2 Auxiliary Feedwater Pump Room Fire Event” (ADAMS Accession No. ML091750166)
06/30/2009	Letter from Entergy Nuclear Operations, Inc., to NRC, “Indian Point Units 2 & 3 - Amendment 8, Revision 1 to License Renewal Application” (ADAMS Accession No. ML091880426)
08/11/2009	07/22/09 Summary of Telephone Conference Call Held Between the NRC and

APPENDIX B: CHRONOLOGY	
Date	**Subject**
	Entergy Nuclear Operations, Inc., Concerning the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application – Buried Piping and Tanks Inspection Program (ADAMS Accession No. ML092190003)
07/27/2009	Letter from Entergy Nuclear Operations, Inc., to NRC, "Questions Regarding Buried Piping Inspections, Indian Point Nuclear Generating Unit Nos. 2 & 3" (ADAMS Accession No. ML09XXXXXXX)
08/11/2009	08/04/09 Summary of Telephone Conference Call Held Between the NRC and Entergy Nuclear Operations, Inc., Concerning Information Provided by Entergy in a Letter dated November 16, 2007 (ADAMS Accession No. ML092190197)
08/11/2009	08/05/09 Summary of Telephone Call Held Between the NRC and Entergy Nuclear Operations, Inc., Concerning Information Provided by Entergy in a Letter dated July 27, 2009 (ADAMS Accession No. ML092190201)
08/06/2009	Letter from Entergy Nuclear Operations, Inc., to NRC, "Additional Information Regarding License Renewal Application – IPEC RAI 2.3A.3.11-1 and Buried Piping and Tanks Inspection Clarifications, Indian Point Nuclear Generating Unit Nos. 2 & 3" (ADAMS Accession No. ML09XXXXXXX)

APPENDIX C

PRINCIPAL CONTRIBUTORS

This appendix lists the principal contributors for the development of this safety evaluation report (SER) and their areas of responsibility.

APPENDIX C: PRINCIPAL CONTRIBUTORS	
Name	**Responsibility**
Kimberly Green	Safety Project Manager
Bill Rogers	Scoping and Screening Methodology
Devender Reddy	Scoping and Screening Methodology
Matthew Homiak	Scoping and Screening Methodology
James Davis	Aging Management Programs and Reviews
Duc Nguyen	Aging Management Programs and Reviews
Surinder Arora	Aging Management Programs and Reviews
Peter Wen	Time-Limited Aging Analyses
Qi Gan	Time-Limited Aging Analyses
On Yee	Time-Limited Aging Analyses
John Tsao	Time-Limited Aging Analyses
Carol Nove	Aging Management Programs
Barry Elliot	Reactor Vessel Neutron Embrittlement
Lambros Lois	Reactor Vessel Fluence
Benjamin Parks	Reactor Systems
Diane Jackson	Reactor Systems
Stanley Gardocki	Mechanical Systems
Steve Jones	Mechanical Systems
Naeem Iqbal	Fire Protection

APPENDIX C: PRINCIPAL CONTRIBUTORS	
Name	**Responsibility**
Pete Barbadoro	Fire Protection
Bruce Heida	Containment Systems
Rao Karipineni	Heating, Ventilation and Air Conditioning
Janak Raval	Heating, Ventilation and Air Conditioning
Sheila Ray	Electrical Systems
Roy Matthew	Electrical Systems
Hans Ashar	Structures
George Thomas	Structures
Bryce Lehman	Structures
John Burke	Steam Generator and Chemicals
Emma Wong	Steam Generator and Chemicals
Timothy Lupold	Nickel Alloy Programs
Keith Hoffman	Nickel Alloy Programs
Jay Collins	Nickel Alloy Programs
Kenneth Chang	Management Oversight
Jerry Dozier	Management Oversight
Rajendar Auluck	Management Oversight
Rani Franovich	Management Oversight
David Wrona	Management Oversight
Greg Cranston	Management Oversight
Donnie Harrison	Management Oversight
Robert Dennig	Management Oversight
Matthew Mitchell	Management Oversight

APPENDIX C: PRINCIPAL CONTRIBUTORS	
Name	**Responsibility**
Terence Chan	Management Oversight
Allen Hiser	Management Oversight
Kamal Manoly	Management Oversight
George Wilson	Management Oversight
Alex Klein	Management Oversight
Richard Morante, Brookhaven National Laboratory (BNL)	Aging Management Programs and Reviews
Joe Braverman, BNL	Aging Management Programs and Reviews
Mano Subudhi, BNL	Aging Management Programs and Reviews
Ken Sullivan, BNL	Aging Management Programs and Reviews

THIS PAGE INTENTIONALLY LEFT BLANK.

APPENDIX D

REFERENCES

This appendix lists the references used throughout this safety evaluation report (SER) for review of the license renewal application (LRA) for Indian Point Nuclear Generating Unit Nos. 2 and 3.

APPENDIX D: REFERENCES
American Concrete Institute (ACI) 202.2R-77
ACI 318, “Building Code Requirements for Structural Concrete”
ACI 349, “Code Requirements for Nuclear Safety-Related Concrete Structures”
American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III, “Rules for Construction of Nuclear Power Plant Components”
ASME Boiler and Pressure Vessel Code, Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components”
ASME Code, Section XI, Appendix G, “Fracture Toughness Criteria for Protection Against Failure”
ASME Code Case N-512, “Assessment of Reactor Vessels with Low Upper-Shelf Charpy Impact Energy Levels”
American National Standards Institute (ANSI) B31.1, “Power Piping”
American Society for Testing Materials (ASTM) Special Technical Publication 1005, “Distillate Fuel: Contamination, Storage and Handling”
ASTM D 445, “Standard Test Method for Kinematic Viscosity of Transparent and Opaque Liquids”
ASTM D 4951, “Standard Test Method for Determination of Additive Elements in Lubricating Oils by Inductively Coupled Plasma Atomic Emission Spectrometry”
ASTM D 96, “Standard Test Method for Water and Sediment in Crude Oil by Centrifuge Method (Field Procedure)”
ASTM E 185, “Standard Practice for Design of Surveillance Programs for Light-Water Moderated Nuclear Power Reactor Vessels”
Branch Technical Position (BTP)_APCSB 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants"

APPENDIX D: REFERENCES
American Society for Metals, “Metals Handbook® Desk Edition,” Copyright 1985
ASTM C 33, “Standard Specification for Concrete Aggregates”
ASTM C 289, “Standard Test Method for Potential Alkali-Silica Reactivity of Aggregates (Chemical Method)”
ASTM C 227, ” Standard Test Method for Potential Alkali Reactivity of Cement-Aggregate Combinations (Mortar-Bar Method)”
ASTM C 295, “Standard Guide for Petrographic Examination of Aggregates for Concrete’
ASTM D 96, “Standard Test Method for Water and Sediment in Crude Oil by Centrifuge Method (Field Procedure)”
ASTM D 445, “Standard Test Method for Kinematic Viscosity of Transparent and Opaque Liquids (and the Calculation of Dynamic Viscosity)”
ASTM D 975, “Standard Practice for Manual Sampling of Petroleum and Petroleum Products”
ASTM D 1796, “Standard Practice for Manual Sampling of Petroleum and Petroleum Products”
ASTM D 2709, “Standard Practice for Manual Sampling of Petroleum and Petroleum Products”
ASTM D 2276, “Standard Test Method for Particulate Contaminant in Aviation Fuel by Line Sampling”
ASTM D 4057, “Standard Practice for Manual Sampling of Petroleum and Petroleum Products”
ASTM D 4951, “Standard Test Method for Determination of Additive Elements in Lubricating Oils by Inductively Coupled Plasma Atomic Emission Spectrometry”
ASTM D 6217, “Standard Test Method for Particulate Contamination in Middle Distillate Fuels by Laboratory Filtration”
Bulletin 80-11, Masonry Wall Design, dated May 8, 1980
Bulletin 87-01, “Thinning of Pipe Walls in Nuclear Power Plants.” Dated July 9, 1987
Bulletin 88-02, “Rapidly Propagating Fatigue Cracks in Steam Generator Tubes,” dated February 5, 1988
Bulletin 88-08, “Thermal Stresses in Piping Connected to Reactor Cooling Systems,” dated June 22, 1988
Bulletin 88-09, “Thermal Stresses in Piping Connected to Reactor Cooling Systems,” dated July 26, 1988

APPENDIX D: REFERENCES
Bulletin 88-11, “Pressurizer Surge Line Thermal Stratification,” December 20, 1988
Bulletin 02-01, “Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,” dated March 18, 2002
Bulletin 02-02, “Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs,” dated August 9, 2002
Bulletin 03-02, “Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity,” dated August 21, 2003
Draft Guide (DG)-1023, “Evaluation of Reactor Pressure Vessels with Charpy Upper-Shelf Energy Less than 50 Ft-Lb,” issued September 1993
Entergy Nuclear Operations, Inc., License Renewal Application for Indian Point Energy Center dated April 23, 2007
Entergy Letter No. NL-03-037, dated March 3, 2003 (ADAMS Accession No. ML030650884)
Entergy Letter No. NL-04-026, dated March 11, 2004 (ADAMS Accession No. ML041610278)
Entergy Letter No. NL-05-001, dated January 17, 2005 (ADAMS Accession No. ML050340067)
Entergy Letter No. NL-06-064, dated July 12, 2006 (ADAMS Accession No. ML062140076)
Entergy Letter No. NL-05-044, dated May 31, 2005 (ADAMS Accession No. ML051590104)
Entergy Letter No. NL-06-064, dated July 12, 2006 (ADAMS Accession No. ML062140076)
Entergy Letter No. NL-08-163, “Indian Point 2 (IP2) Nuclear Power Plant Amendment Update to the Final Safety Analysis Report (FSAR), Revision 21,” dated October 20, 2008
Generic Letter (GL) 86-10, “Implementation of Fire Protection Requirements.” dated April 24, 1986
GL 88-05, “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR plants,” dated March 17, 1988
GL 89-08, “Erosion/Corrosion-Induced Pipe Wall Thinning,” dated May 2, 1989
GL 89-13, “Service Water System Problems Affecting Safety-Related Equipment,” dated July 18, 1989
GL 92-01, “Reactor Vessel Structural Integrity,” issued February 28, 1992
GL 2004-02, “Potential Impact of Debris Blockage on Emergency Recirculation during Design Basis Accidents at Pressurized-Water Reactors”

APPENDIX D: REFERENCES
GL 2007-01, “Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients,” dated February 7, 2007
Generic Safety Issue (GSI)-191, “Assessment of Debris Accumulation on PWR Sump”
Information Notice (IN) 89-53, “Rupture of Extraction Steam Line on High Pressure Turbine,” dated June 13, 1989
IN 90-04, “Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators,” dated January 26, 1990
IN 94-63, “Boric Acid Corrosion of Charging Pump Casing Caused by Cladding Cracks,” dated August 30, 1994
IN 97-11, “Cement Erosion From Containment Subfoundations at Nuclear Power Plants,” dated March 21, 1997
IN 97-84, “Rupture in Extraction Steam Piping as a Result of Flow-Accelerated Corrosion,” dated December 11, 1997
IN 00-14, “Non-Vital Bus Fault Leads to Fire and Loss of Offsite Power,” dated September 27, 2000
IN 02-12, “Submerged Safety-Related Electrical Cables,” dated April 21, 2002
ISO 4406, “Hydraulic Fluid Power - Fluids - Method for Coding the Level of Contamination by Solid Particles - Second Edition”
Letter from NRC to W.H. Rasin, Nuclear Management and Resources Council, “Safety Assessment of WCAP-13587, Revision 1, ‘Reactor Vessel Upper Shelf Energy Bounding Evaluation for Westinghouse Pressurized Water Reactors,’ September 1993,” April 21, 1994 (ADAMS Public Legacy Library Accession No. 9405060287)
Letter from Christopher I. Grimes, NRC to Douglas J. Walters, Nuclear Energy Institute, Subject: License Renewal Issue No. 98-0030, “Thermal Aging Embrittlement Of Cast Austenitic Stainless Steel Components,” dated May 19, 2000 (ADAMS Accession No. ML003717179)
Letter from David B. Matthews, NRC to Messrs. Alan Nelson and David Lochbaum, "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))," dated April 1, 2002
Letter from Pao-Tsin Kuo, NRC to Messrs. Alan Nelson and David Lochbaum, "Standardized Format for License Renewal Applications," dated April 7, 2003

APPENDIX D: REFERENCES
Letter from NRC to Entergy, “Indian Point Nuclear Generating Unit No. 2 - Issuance of Amendment Re: 3.26 Percent Power Uprate (TAC No. MC1865),” October 27, 2004 (ADAMS Accession No. ML042960007),
Letter from NRC to Entergy, “Indian Point Nuclear Generating Unit No. 3 - Issuance of Amendment Re: 4.85 Percent Stretch Power Uprate and Relocation of Cycle-Specific Parameters (TAC No. MC3552),” March 24, 2005 (ADAMS Accession No. ML050600380).
License Renewal Interim Staff Guidance (LR-ISG)-2007-02, “Changes to Generic Aging Lesson Learned (GALL) Report Aging Management Program (AMP) XI.E6, ‘Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements’”
Nuclear Safety Analysis Center (NSAC)-202L-R2, “Recommendations for an Effective Flow-Accelerated Corrosion Program,” April 1999
NSAC-202L-R3, “Recommendations for an Effective Flow-Accelerated Corrosion Program,” May 2006
NEI 95-10, Revision 6, “Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule,” June 2005.
NUREG-0313, “Technical Report on Material Selection& Processing GL For BWR Coolant Press Boundary Piping”
NUREG-0800, “Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants”
NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum from Director, NRR to NRR Staff," November 1976.
NUREG-1339, “Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," June 1990
NUREG-1557, “Summary of Technical Information and Agreements from Nuclear Management and Resources Council Industry Reports Addressing License Renewal"
NUREG-1785, “Safety Evaluation Report Related to the License Renewal of H.B. Robinson Steam Electric Plant, Unit 2,” issued March 2004.
NUREG-1800, Revision 1, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” September 2005.
NUREG-1801, Revision 1, “Generic Aging Lessons Learned (GALL) Report, “September 2005.
NUREG/CR-6260, “Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components"

APPENDIX D: REFERENCES
NRC Inspection Report 05000247/2009002, dated May 14, 2009 (ADAMS Accession No. ML091340445)
Regulatory Guide (RG) 1.65, "Materials and Inspections for Reactor Vessel Closure Studs," October 1973
RG 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," issued May 1988 (ADAMS Accession No. ML003740284)
RG 1.127, Revision 1, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," March 1978
RG 1.137, Revision 1, "Fuel-Oil Systems for Standby Diesel Generators," October 1979
RG 1.147, Revision 15, "Inservice Inspection Code Case Acceptability, ASME Section XI, Division 1," October 2007
RG 1.160, Revision 2, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," March 1997
RG 1.161, "Evaluation of Reactor Pressure Vessels with Charpy Upper-Shelf Energy Less Than 50 Ft-Lb," issued June 1995 (ADAMS Accession No. ML003740038)
RG 1.163, "Performance-Based Containment Leak-Test Program," September 1995
RG 1.188, Revision 1, "Standard Format and Content for Applications To Renew Nuclear Power Plant Operating Licenses," September 2005.
RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence" issued March 2001 (ADAMS Accession No. ML010890301)
Regulatory Issue Summary (RIS) 2003-13, "NRC Review of Responses to Bulletin 2002-01, 'Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,'" dated July 29, 2003
Safety Evaluation Report (SER) By the Directorate of Licensing U.S. Atomic Energy Commission in the Matter of Consolidated Edison Company of New York, Inc., Indian Point Nuclear Generating Unit No. 3, Docket No. 50-286, dated September 21, 1973 (ADAMS Accession No. ML072260465)
SER Related to the Issuance of Amendment 36 to Facility Operating License No. DPR-26 and Amendment No. 10 to Facility Operating License No. DPR-64, dated November 30, 1977 (ADAMS Accession No. ML003781118)
SER Related to the Issuance of Amendment 37 to Facility Operating License No. DPR-26 and Amendment No. 11 to Facility Operating License No. DPR-64, dated February 3, 1978 (ADAMS Accession No. ML003774906)

APPENDIX D: REFERENCES
SER Related to the Issuance of Amendment 46 to Facility Operating License No. DPR-26, dated January 31, 1979 (ADAMS Accession No. ML003775054)
SER Related to the Issuance of Amendment 24 to Facility Operating License No. DPR-64 for the Indian Point Nuclear Generating Plant, Unit No. 3, dated March 6, 1979 (ADAMS Accession No. ML003778749)
SER Supplement to Fire Protection Safety Evaluation Supporting Additional Modifications re Change from Reliance Upon Fire Rated Door to Reliance Upon Water, dated May 2, 1980 (ADAMS Public Legacy Library Accession Nos. 8005270021 and 8005270023)
SER Related to the Issuance of Amendment 64 to Facility Operating License No. DPR-26, dated October 31, 1980 (ADAMS Accession No. ML003778538)
SER Related to the Issuance of Amendment 45 to Facility Operating License No. DPR-64, Modifying Plant Fire Protection System, dated November 18, 1982 (ADAMS Public Legacy Library Accession Nos. 8211300426 and 8211300429)
SER Related to Environmental Qualification of Safety-Related Electric Equipment, dated December 30, 1982 (ADAMS Public Legacy Library Accession Nos. 8301040473 and 8301040482)
SER Related to Safe Shutdown Capability, dated August 22, 1983 (ADAMS Public Legacy Library Accession No. 8309080181)
SER Related to Exemption from 10 CFR 50, Appendix R, Sections III.G.2 & 3 re Upper Electrical Penetration Areas and Cable Tunnels and Sump Pump and Control Rooms, dated February 2, 1984 (ADAMS Public Legacy Library Accession Nos. 8402170506 and 8402170510)
SER Related to Appendix R to 10 CFR 50, Sections III.G & III.L re Safe Shutdown Capability, dated March 30, 1984 (ADAMS Public Legacy Library Accession No. 8404110574)
SER Related to Alternate Shutdown Power Supply, Process Monitoring and PORV Operator Action per Appendix R, Sections III.G.3 and III.L, dated April 16, 1984 (ADAMS Public Legacy Library Accession Nos. 8405010052, 8405010057, 8405010061)
SER Related to Exemption from Requirements of Appendix R to 10 CFR 50 re Fire Protection, dated October 16, 1984 (ADAMS Public Legacy Library Accession Nos. 8410290219, 8410290223, 8410290224)
SER Supporting NRC Recommendation to Grant Licensee Exemption Request re Penetration Seals in Control Room Floor, dated September 16, 1985 (ADAMS Public Legacy Library Accession No. 8509190273)

APPENDIX D: REFERENCES
SER Granting July 13, 1985 Request for Exemption from 10 CFR 50, Appendix R, Section III.J, dated November 13, 1985 (ADAMS Public Legacy Library Accession Nos. 8511250495, 8511250496, 8511250498)
SER for Exemption Granting Seven Exemptions from the Technical Requirements of Sections III.G and III.J of Appendix R to 10 CFR 50, dated January 7, 1987 (ADAMS Accession No. ML003779008)
SER for Exemption Granting July 13, 1983 Request for Relief from Technical Requirements of Section III.G.2 of 10 CFR 50, Appendix R, dated March 4, 1987 (ADAMS Public Legacy Library Accession Nos. 8703110128 and 8703110193)
SER Accepting Utility Reevaluation of Alternative Shutdown Capability in Accordance with Requirements of Appendix R to 10 CFR 50, Section III.G.3 and III.L, dated September 9, 1988 (ADAMS Public Legacy Library Accession Nos. 8809150139 and 8809150145)
SER Supporting September 11, 1985 and September 14, 1988 Submittals of Clarifications to Post-Fire Safe Shutdown Methodology and Fire Protection Program, dated January 12, 1989 (ADAMS Public Legacy Library Accession Nos. 8901190302 and 8901190306)
SER Related to the Issuance of Amendment 110 to Facility Operating License No. DPR-64 for the Indian Point Nuclear Generating Unit No. 3, dated October 21, 1991 (ADAMS Accession No. ML003779328)
SER Related to the Issuance of Amendment 146 to Facility Operating License No. DPR-64 for the Indian Point Nuclear Generating Unit No. 3, dated April 20, 1994 (ADAMS Accession No. ML003780221)
SER Related to the Issuance of an Exemption from the Requirements of 10 CFR Part 50, Appendix R, Section III.G.2 -Indian Point Nuclear Generating Unit No. 3, dated January 5, 1995 (ADAMS Accession No. ML003780510)
SER Related to the Issuance of Amendment 186 to Facility Operating License No. DPR-26, dated March 26, 1996 (ADAMS Accession No. ML003778424)
SER for IP2 dated October 15, 2004 (ADAMS Accession No. ML042890389)
SER for IP3 dated April 4, 2005 (ADAMS Accession No. ML050940136)
SER for IP3 dated March 18, 2005 (ADAMS Accession No. ML050770010),
SER for IP2 dated February 27, 2006 (ADAMS Accession No. ML060090142)
Title 10 of the *Code of Federal Regulations*, Part 20, “Standards for Protection Against Radiation”

APPENDIX D: REFERENCES
Title 10 of the *Code of Federal Regulations,* Part 50, “Domestic Licensing of Production and Utilization Facilities”
Title 10 of the *Code of Federal Regulations*, Part 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants”
Title 10 of the *Code of Federal Regulations*, Part 100, “Reactor Site Criteria”
WCAP-12866, "Bottom-Mounted Instrumentation Flux Thimble Wear," January 1991
WCAP-13587, “Reactor Vessel Upper Shelf Energy Bounding Evaluation for Westinghouse Pressurized Water Reactors," February 1993 (ADAMS Public Legacy Library Accession No. 9303230154)
WCAP-13587, Revision 1, “Reactor Vessel Upper Shelf Energy Bounding Evaluation for Westinghouse Pressurized Water Reactors," September 1993
Safety Evaluation for WCAP-13587, Revision 1 (ADAMS Public Legacy Library Accession No. 9405060287)
Safety Evaluation for WCAP-14574, Revision 0, dated October 26, 2000 (ADAMS Accession No. ML003763768)
WCAP-14577, Revision 1-A, “License Renewal Evaluation: Aging Management for Reactor Internals," dated April 9, 1001 (ADAMS Accession No. ML011080790)
WCAP-15557, Revision 0, "Qualification of the Westinghouse Pressure Vessel Neutron Fluence Evaluation Methodology," S. L. Anderson, August 2000
WCAP-15629, Revision 1, “Indian Point Unit 2 Heatup and Cooldown Limit Curves for Normal Operation and PTLR Support Documentation,” T. J. Laubham, December 2001 (ADAMS Accession No. ML020170071)
WCAP-15805, “Analysis of Capsule X from the Carolina Power and Light Company H.B. Robinson Unit 2 Reactor Vessel Radiation Surveillance Program,” T. J. Laubham et al., Westinghouse Electric Company LLC, March 2002. (ADAMS Accession No. ML0211190313)
WCAP-16157-NP, “Stretch Power Uprate NSSS and BOP” (ADAMS Accession No. ML040370423
WCAP-16251-NP, “Analysis of Capsule X from Entergy's Indian Point Unit 3 Reactor Vessel Radiation Surveillance Program,” July 29 2004 (ADAMS Accession No. ML042320088)