NUREG-1930, Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Plant, Units 2 and 3

Supplement 3

Docket Nos. 50-247 and 50-286

ABSTRACT

This document is the third supplement to NUREG-1930, "Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3," regarding the license renewal application (LRA) for Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3). By letter dated April 23, 2007 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML071210512), as supplemented by letters dated May 3, 2007 (ADAMS Accession No. ML071280700) and June 21, 2007 (ADAMS Accession No. ML071800318), Entergy Nuclear Operations, Inc., ("Entergy" or "the applicant") submitted an LRA in accordance with Title 10, "Energy," of the *Code of Federal Regulations* (10 CFR) Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants." Entergy requested renewal of the IP2 and IP3 operating licenses (Facility Operating License Nos. DPR-26 and DPR-64, respectively) for a period of 20 years beyond the expiration of the initial operating licenses, which occurred at midnight on September 28, 2013, for IP2; and at midnight on December 12, 2015, for IP3. The U.S. Nuclear Regulatory Commission's (NRC's) regulation at 10 CFR 2.109, "Effect of Timely Renewal Application," implements the "timely renewal" provision of Section 9(b) of the Administrative Procedure Act, Title 5, "Government Organization and Employees," of the U.S. Code (U.S.C.), Section 558(c). Under this regulation, if an applicant requests a renewed license at least 5 years before expiration of its current license, the request is considered "timely," and the facility is allowed to continue to operate under its existing license until the NRC completes its review and reaches a decision on the license renewal request. At midnight on September 28, 2013, IP2 entered this period of operation under the above provision. At midnight on December 12, 2015, IP3 entered this period of operation under the above provision.

The staff published its safety evaluation report (SER) in the two volumes of NUREG-1930 in November 2009 (ADAMS Accession Nos. ML093170451 and ML093170671), which summarized the results of its LRA safety review for compliance with the requirements of 10 CFR Part 54. In August 2011, the staff issued Supplement 1 to NUREG-1930 (supplemental safety evaluation report (SSER 1)) (ADAMS Accession No. ML11242A215), which documented the staff's review of supplemental information the applicant provided since the issuance of the SER as documented in NUREG-1930. In July 2015, the staff issued Supplement 2 to NUREG-1930 (SSER 2) (ADAMS Accession No. ML15188A383), which documented the staff's review of supplemental information provided by the applicant since the issuance of SSER 1. Supplement 3 to NUREG-1930 (SSER 3) documents the staff's review of supplemental information the applicant provided since the issuance of SSER 2. This includes information provided in response to staff requests for additional information. This document discusses only the changes to the SER, SSER 1, and SSER 2.

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ABBREVIATIONS

A/LAI	applicant/licensee action item
ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards
ADAMS	Agencywide Documents Access and Management System
AERM	aging effect requiring management
AMP	aging management program
AMR	aging management review
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
BFP	baffle-former bolt
CFR	*Code of Federal Regulations*
CIV	containment isolation valve
CLB	current licensing basis
CO_2	carbon dioxide
CPVC	chlorinated polyvinyl chloride
CUF	cumulative usage factor
CUI	corrosion under isolation
EDG	emergency diesel generator
EFPY	effective full-power year
Entergy	Entergy Nuclear Operations, Inc.
EPRI	Electric Power Research Institute
EQ	environmental qualification
F_{en}	environmental fatigue life correction factor
FR	*Federal Register*
FSAR	final safety analysis report
GALL	Generic Aging Lessons Learned (Report)
HVAC	heating, ventilation, and air conditioning
I&C	instrumentation and controls
IASCC	irradiation-assisted stress corrosion cracking
ILRT	integrated leak rate test
IP1	Indian Point Unit 1
IP2	Indian Point Unit 2
IP3	Indian Point Unit 3
IPEC	Indian Point Energy Center
ISG	interim staff guidance
ISI	inservice inspection
IVSW	isolation valve seal water (system)
LCO	limiting condition for operation
LER	licensee event report
LLRT	local leak rate testing

LRA	license renewal application
LR-ISG	license renewal interim staff guidance
LTOP	low-temperature overpressure protection
MIC	microbiologically-influenced corrosion
MRP	Materials Reliability Program
NDE	nondestructive examination
NEI	Nuclear Energy Institute
NFPA	National Fire Protection Association
NRC	U.S. Nuclear Regulatory Commission
NSAL	Nuclear Safety Advisory Letter
NSSS	nuclear steam supply system
pH	potential of hydrogen
ppm	parts per million
P-T	pressure-temperature
PTS	pressurized thermal shock
PVC	polyvinyl chloride
PWR	pressurized water reactor
PWSCC	primary water stress corrosion cracking
RAI	request for additional information
RCPB	reactor coolant pressure boundary
RG	regulatory guide
RHR	residual heat removal
RIC	recurring internal corrosion
RVI	reactor vessel internals
RWST	refueling water storage tank
SBO	station blackout
SCC	stress corrosion cracking
SE	safety evaluation
SER	safety evaluation report
SG	steam generator
SGMP	Steam Generator Management Program
SRP	Standard Review Plan
SRP-LR	Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants
SSC	system, structure, or component
SSER 1	Supplemental Safety Evaluation Report 1(to NUREG-1930)
SSER 2	Supplemental Safety Evaluation Report 2 (to NUREG-1930
SSER 3	Supplemental Safety Evaluation Report 3 (to NUREG-1930)
TLAA	time-limited aging analysis
TS	technical specification(s)
UFSAR	updated final safety analysis report
U.S.C.	U.S. Code
UT	ultrasonic testing

WCAP	Westinghouse Commercial Atomic Power
WC&PPS	weld channel and penetration pressurization system

SECTION 1
INTRODUCTION AND GENERAL DISCUSSION

1.0 Introduction

This document is the third supplement to NUREG-1930, "Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3," regarding the license renewal application (LRA) for Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3). By letter dated April 23, 2007, (Agencywide Documents Access and Management System (ADAMS) Accession No. ML071210512), as supplemented by letters dated May 3, 2007 (ADAMS Accession No. ML071280700) and June 21, 2007 (ADAMS Accession No. ML071800318), Entergy Nuclear Operations, Inc., ("Entergy" or "the applicant") submitted an LRA in accordance with Title 10, "Energy," of the *Code of Federal Regulations* (10 CFR) Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants." Entergy requested renewal of the IP2 and IP3 operating licenses (Facility Operating License Nos. DPR-26 and DPR-64, respectively) for a period of 20 years beyond the expiration of the initial operating licenses, which occurred at midnight on September 28, 2013, for IP2; and at midnight on December 12, 2015, for IP3. The U.S. Nuclear Regulatory Commission's (NRC's) regulation at 10 CFR 2.109, "Effect of Timely Renewal Application," implements the "timely renewal" provision of Section 9(b) of the Administrative Procedure Act, Title 5, "Government Organization and Employees," of the U.S. Code (U.S.C.), Section 558(c). Under this regulation, if an applicant requests a renewed license at least 5 years before expiration of its current license, the request is considered "timely," and the facility is allowed to continue to operate under its existing license until the NRC completes its review and reaches a decision on the license renewal request. At midnight on September 28, 2013, IP2 entered this period of operation under the above provision. At midnight on December 12, 2015, IP3 entered this period of operation under the above provision.

The staff published its safety evaluation report (SER) in the two volumes of NUREG-1930 in November 2009 (ADAMS Accession Nos. ML093170451 and ML093170671), which summarized the results of its LRA safety review for compliance with the requirements of 10 CFR Part 54. In August 2011, the staff issued Supplement 1 to NUREG-1930 (supplemental safety evaluation report (SSER 1) (ADAMS Accession No. ML11242A215), which documented the staff's review of supplemental information provided by the applicant since the issuance of the SER as documented in NUREG-1930. In July 2015, the staff issued Supplement 2 to NUREG-1930 (SSER 2) (ADAMS Accession No. ML15188A383), which documented the staff's review of supplemental information provided by the applicant since the issuance of SSER 1. This supplement to NUREG-1930 (SSER 3) documents the staff's review of supplemental information provided by the applicant since the issuance of SSER 2. This includes information provided in response to staff requests for additional information. This document discusses only the changes to the SER, SSER 1, and SSER 2. This SSER supplements portions of SER Sections 2, 3, and 4 and Appendices A and B.

1.4 Interim Staff Guidance

Table 1.4-1 shows the set of interim staff guidance (ISG) documents that the staff evaluated for this supplement, and the SER sections in which they are addressed.

Table 1.4-1

ISG	Purpose	SSER Section
Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation (LR-ISG-2012-02)	Provides revised guidance in managing aging for the subject components and includes new recommendations for corrosion under insulation (CUI) of component external surfaces, and clarifies guidance for using the pressurization option for inspecting elastomers in GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components."	3.0.3.2.1 3.0.3.2.5 3.0.3.4 3.2A.2.3.2 3.2A.2.3.4 3.2B.2.3.2 3.2B.2.3.4 3.3.2.1.2 3.3A.2.3.4 3.3A.2.3.14 3.3A.2.3.35 3.3B.2.3.4 3.4A.2.3.3 3.4B.2.3.3
Aging Management of Loss of Coating or Lining Integrity for Internal Coatings and Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (LR-ISG-2013-01)	Incorporates recommendations related to managing loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage, and spalling for cementitious coatings/linings.	3.0.3.3.11 3.0.3.4 3.3A.2.3.1 3.3A.2.3.8 3.3B.2.3
Changes to Buried Piping and Underground Piping and Tank Recommendations (LR-ISG-2015-01)	Incorporates recommendations associated with AMP XI.M41, "Buried and Underground Piping and Tanks," including technical and editorial changes.	3.0.3.1.2 3.3A.2.3.15 3.3B.2.3.13 3.3B.2.3.14
Changes to Aging Management Guidance for Various Steam Generator Components (LR-ISG-2016-01)	Revises GALL AMP XI.M19, "Steam Generators," SRP-LR Sections 3.1.2.2.11 and 3.1.3.2.11, "Cracking due to Primary Water Stress Corrosion Cracking" of divider plate assemblies and tube-to-tubesheets, and the associated FSAR supplement.	3.0.3.2.14 3.0.3.5 3.1.2.1 3.1.2.2.16

1.7 Annual Updates to the License Renewal Application

In accordance with 10 CFR 54.21(b), each year following submittal of the LRA and at least 3 months before the scheduled completion of the NRC review, an amendment to the renewal application must be submitted that identifies any change to the current licensing basis (CLB) of the facility that materially affects the contents of the LRA, including the final safety analysis report (FSAR) supplement. Since preparation of SSER 2, by letters dated December 15, 2014; December 14, 2015; December 15, 2016; and December 14, 2017 (ADAMS Accession

Nos. ML14364A156, ML15352A028, ML16358A526, and ML17360A157, respectively), Entergy submitted amendments to the LRA (Amendment Nos. 16-19, respectively) providing the required updates to the CLB. The staff's review of the CLB changes are included in this supplement.

1.8 Closure Agreement

On February 8, 2017 (ADAMS Accession No. ML17044A005), Entergy submitted to the NRC an amendment to the LRA reflecting shortened license renewal terms for IP2 and IP3 in accordance with the closure agreement it submitted to the NRC's Atomic Safety and Licensing Board.

Under the agreement, IP2 will shut down by April 30, 2020, and IP3 will shut down by April 30, 2021, subject to potential operating extensions through, but not beyond, 2024 and 2025, respectively, under limited circumstances specified in the agreement.

Although the closure agreement calls for early shutdown of the units, the shortened periods of extended operation do not affect any of the conclusions presented in this supplement.

SECTION 2
STRUCTURES AND COMPONENTS SUBJECT TO AGING MANAGEMENT REVIEW

2.4 <u>Scoping and Screening Results: Structures</u>

2.4.3 Turbine Buildings, Auxiliary Buildings, and Other Structures

2.4.3.1 Summary of Technical Information in the Application

Indian Point Nuclear Generating Unit No.1's (IP1's) 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 Indian Point Nuclear Generating Unit No. 2's (IP2's) Control Building, the Emergency Diesel Generator Building, and in-scope Indian Point Nuclear Generating Unit No. 3's (IP3's) structures.
To eliminate this risk, as provided in an annual update dated December 15, 2014 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML14364A156), the applicant partially removed the stack, so that it no longer serves a 10 CFR 54.4(a)(2) function and has been deleted from the scope of license renewal. Accordingly, references to the stack have been removed from the affected sections of the applicant's LRA in Table 2.2-3, Table 2.4-3, Table 3.5.2-3, A.2.1.35, and B.1.36.

SECTION 3
AGING MANAGEMENT REVIEW RESULTS

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

Subsequent to Entergy Nuclear Operations, Inc. ("Entergy" or "the applicant") submitting its license renewal application (LRA) for Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3), the U.S. Nuclear Regulatory Commission ("NRC" or "the staff") issued several license renewal interim staff guidance (LR-ISG) documents. The applicant revised its aging management programs (AMPs) and aging management review (AMR) items and in some cases incorporated new AMR items to address these ISGs. The staff's evaluation of these changes is documented in the SER. Except where the applicant proposed changes to existing AMR items or new AMR items, for the following ISGs the staff documented its evaluation of the applicant's proposed changes only in the AMP portion of the SER.

- LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation"
- LR-ISG-2015-01, "Changes to Buried and Underground Piping and Tank Recommendations"

Based on the staff's review of industry operating experience, these ISGs enhanced the recommendations in several Generic Aging Lessons Learned (GALL) Report AMPs. Examples of the enhancements are as follows:

- AMP XI.M27, "Fire Water System": included many new tests and inspections based on those described in NFPA-25, "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," and augmented inspections or tests of portions of water-based fire protection system components that have been wetted but are normally dry and that cannot be drained or piping segments that allow water to collect.
- AMP XI.M29, "Aboveground Metallic Tanks": included corrosion under insulation (CUI) as an aging effect requiring management (AERM), and tank internal and external surface inspection recommendations were expanded depending on the type of material, environment, and aging effect.
- AMP XI.M36, "External Surfaces Monitoring of Mechanical Components": included CUI as an AERM.
- AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components": revised the program from inspections being opportunistic to recommending a minimum sample of inspections for each material, environment, and aging effect combination.
- AMP XI.M41, "Buried and Underground Piping and Tanks": expanded the preventive action recommendations to include cathodic protection and backfill quality in addition to coatings, and based inspection quantities on the performance of the cathodic protection system, coatings, backfill quality, plant-specific operating experience, and soil testing.

The basis for not revising the existing AMR item SER input is that: (a) the applicant's changes to the AMPs to ensure consistency with the revised recommendations in the ISGs strengthened the staff's basis for accepting the applicant's proposed methods to manage aging effects associated with the material and environment combination, and (b) the staff's evaluation of changes to each AMP is documented in the SER input for the AMP.

3.0.3 Aging Management Programs

By letter dated December 15, 2014 (ADAMS Accession No. ML14364A156), the applicant amended several updated final safety analysis report (UFSAR) supplement descriptions to correct typographical errors. Examples include: (a) adding the term "Final" in front of Safety Evaluation Report in LRA Section A.2.0, (b) inserting the term "to" in front of the period of extended operation in LRA Section A.2.1.5, and (c) defining the acronym "CUF," as cumulative usage factor in LRA Section A.2.1.11. The staff finds that the changes are editorial in nature and do not affect the technical content of the LRA.

3.0.3.1 AMPs Consistent with the GALL Report

3.0.3.1.2 Buried Piping and Tanks Inspection Program

Summary of Technical Information in the Application. By letter dated April 28, 2017 (ADAMS Accession No. ML17129A605), the applicant provided changes related to the Buried Piping and Tanks Inspection Program after the issuance of Supplement 2 to the SER (ADAMS Accession No. ML15188A383). These changes were to address LR-ISG-2015-01, "Changes to Buried and Underground Piping and Tank Recommendations," which replaces AMP XI.M41, "Buried and Underground Piping and Tanks," and the associated UFSAR summary description issued in LR-ISG-2011-03, "Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program (AMP) XI.M41, 'Buried and Underground Piping and Tanks'."

Staff Evaluation. The staff's previous evaluation of the applicant's Buried Piping and Tanks Inspection Program is documented in Section 3.0.3.1.2 of SSER 2.

The staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through seven of the applicant's updated Buried Piping and Tanks Inspection Program to the corresponding program elements of GALL Report AMP XI.M41, as modified by LR-ISG-2015-01.

For the "preventive actions," "parameters monitored or inspected," and "corrective actions" program elements, the staff determined the need for additional information, which resulted in the issuance of requests for additional information (RAIs), as discussed below.

The number of recommended inspections for buried stainless steel piping in GALL Report AMP XI.M41, as modified by LR-ISG-2015-01, is based on coatings meeting the "preventive actions" program element. This program element recommends that coatings are provided for buried stainless steel or the applicant provides justification when coatings are not provided. However, during its review, the staff noted that it was unclear if buried stainless steel piping is coated. By letter dated June 27, 2017 (ADAMS Accession No. ML17170A286), the staff issued RAI 3.0.3.1.2-1 requesting that the applicant state whether buried stainless steel piping is coated, and if it is not coated, to provide justification for why coatings do not need to be provided.

In its response dated July 27, 2017 (ADAMS Accession No. ML17216A030), the applicant stated that in-scope buried stainless steel piping is not coated. The justification provided by the applicant was that soil testing has determined that soils around the piping are non-aggressive; and two locations of stainless steel piping will be inspected in each 10-year period during the period of extended operation, which exceeds the recommendations of GALL Report AMP XI.M41. The staff reviewed documents associated with the Buried Piping and Tanks Inspection Program while conducting an audit of the Service Water Integrity License Renewal Aging Management Program. As documented in the audit report (ADAMS Accession No. ML17250A244), the staff reviewed the measured values of soil resistivity, pH, redox potentials, sulfides, chlorides, and moisture that were used to determine soil corrosivity at eight test locations at the site.

The staff noted that soil is considered aggressive for uncoated stainless steel when soil resistivity is less than 1,000 ohm-cm, pH is less than 4.5, and chlorides are more than 500 ppm.[1] The staff finds the applicant's response acceptable because: (a) the measured values of soil resistivity, pH, and chlorides reviewed by the staff during the audit were within these limits, confirming that the soil is non-aggressive for uncoated stainless steel; and (b) the applicant will conduct two inspections of stainless steel piping in each 10-year period during the period of extended operation, which is more conservative when compared to GALL Report AMP XI.M41 which recommends one inspection. The staff's concern described in RAI 3.0.3.1.2-1 is resolved.

The "parameters monitored" program element of GALL Report AMP XI.M41, as modified by LR-ISG-2015-01, recommends visual inspections of the external surface of polymeric materials to detect loss of material due to wear. However, during its review, the staff noted that polyvinyl chloride (PVC) piping exposed to soil in the plant drains system is not within the scope of the Buried Piping and Tanks Inspection Program because the applicant claimed that there are no aging effects due to the lack of stressors in a soil environment and non-aggressive soil as confirmed by soil samples. GALL Report AMP XI.M41, as modified by LR-ISG-2015-01, recommends managing loss of material due to wear for buried polymeric components with the number of inspections based on backfill quality. By letter dated June 27, 2017, the staff issued RAI 3.0.3.1.2-2 requesting that the applicant state the basis for why loss of material due to wear is not an AERM for PVC piping exposed to soil.

In its response dated July 27, 2017, the applicant stated: (a) the backfill around the PVC piping consists of 6 inches of sand free of any foreign material, and (b) one location of PVC piping will be visually inspected in each 10-year period during the period of extended operation to detect loss of material due to wear.

The staff finds the applicant's response acceptable because: (a) sand free of any foreign material meets the intent of the American Society for Testing and Materials (ASTM) D 448-08, which demonstrates that backfill is in accordance with the "preventive actions" program element of GALL Report AMP XI.M41; and (b) one location of PVC piping will be inspected in each 10-year period during the period of extended operation, which is consistent with GALL Report AMP XI.M41 regarding inspections of polymeric piping when backfill is in accordance with the "preventive actions" program element. The staff's concern described in RAI 3.0.3.1.2-2 is resolved.

The "parameters monitored" program element of GALL Report AMP XI.M41, as modified by LR-ISG-2015-01, recommends inspections for cracking due to stress corrosion cracking for

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[1] Corrosion Resistance of Stainless Steels in Soils and in Concrete (paper presented at the Plenary Days of the Committee on the Study of Pipe Corrosion and Protection), Biarritz, France, October 2001, Pierre-Jean Cunat.

steel and stainless steel. The applicant stated that cracking is not an AERM for stainless steel based on cathodic protection levels, soil conditions, and operating temperatures below 140°F. However, during its review, the staff noted that: (a) the threshold temperature for stress corrosion cracking of stainless steel is based on the component being exposed to a treated water environment (i.e., water whose chemistry has been altered and is maintained); however, due to the potential presence of halides, stress corrosion cracking is an applicable aging effect for stainless steel piping exposed to soil; and (b) the applicant did not address cracking of steel, which could occur in a carbonate/bicarbonate environment depending on cathodic polarization level, temperature, and pH. By letter dated June 27, 2017, the staff issued RAI 3.0.3.1.2-3 requesting that the applicant state the basis for why cracking is not an AERM for stainless steel and steel piping exposed to soil.

In its response dated July 27, 2017, the applicant stated that stainless steel and steel piping will be visually inspected for evidence of cracking. During the Service Water Integrity License Renewal Aging Management Program audit, the staff reviewed a plant-specific procedure for performing visual inspections of buried and underground piping and tanks. As documented in the audit report, the staff noted that visual inspections of buried and underground piping and tanks are: (a) performed with sufficient illumination and resolution to assess the component for indications of cracking; (b) conducted by personnel having an annual eye examination and visual acuity specified in CEP-NDE-100, “Administration and Control of NDE,” and/or American Society of Mechanical Engineers (ASME) Code Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components,” IWA-2321, “Vision Tests,” and (c) conducted by personnel who are VT-1 qualified.

The staff finds the applicant’s response acceptable because qualified personnel conducting visual inspections with adequate lighting and resolution can be sufficiently rigorous to assess for the impact of cracks on the pressure boundary function of the component. The staff’s concern described in RAI 3.0.3.1.2-3 is resolved.

The “corrective actions” program element of GALL Report AMP XI.M41, as modified by LR-ISG-2015-01, recommends that when coatings, backfill, or the condition of exposed piping does not meet acceptance criteria such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is extrapolated to the end of the period of extended operation, an increase in the sample size is conducted. However, during its review, the staff noted that the increase in sample size for the Buried Piping and Tanks Inspection Program is conducted when future inspections reveal significant coating damage caused by non-conforming backfill, which is only an example of how degradation of the base metal could occur (e.g., coating degradation based on coating service life). By letter dated June 27, 2017, the staff issued RAI 3.0.3.1.2-4 requesting that the applicant state the basis for why an increase in inspection sample size will only occur when significant coating damage caused by non-conforming backfill is revealed.

In its response dated July 27, 2017, the applicant revised its Buried Piping and Tanks Inspection Program to be consistent with GALL Report AMP XI.M41, as modified by LR-ISG-2015-01, regarding criteria for increasing inspection sample size. The staff’s concern described in RAI 3.0.3.1.2-4 is resolved.

Based on its review of the applicant’s responses to RAIs 3.0.3.1.2-1, 3.0.3.1.2-2, 3.0.3.1.2-3, and 3.0.3.1.2-4, the staff finds that program elements one through seven for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M41, as modified by LR-ISG-2015-01.

Operating Experience. There are no changes or updates to this SER section.

Updated Final Safety Analysis Report (UFSAR) Supplement. LRA Sections A.2.1.5 and A.3.1.5, as modified by letter dated April 28, 2017 (ADAMS Accession No. ML17110A133), provide the UFSAR supplements for the Buried Piping and Tanks Inspection Program at Units 2 and 3, respectively. The staff reviewed this UFSAR supplement description of the program against the recommended description for this type of program as described in SRP-LR Table 3.0-1, as modified by LR-ISG-2015-01, and noted that aspects of the UFSAR summary description issued in LR-ISG-2015-01 were not included in the revised LRA Sections A.2.1.5 and A.3.1.5 (e.g., inspections are conducted by qualified individuals). The licensing basis for this program for the period of extended operation may not be adequate if the applicant does not incorporate this information in its UFSAR supplement. By letter dated June 27, 2017, the staff issued RAI 3.0.3.1.2-5 requesting that the applicant state the basis for not including aspects of the UFSAR summary description issued in LR-ISG-2015-01 in the revised LRA Sections A.2.1.5 and A.3.1.5.

In its response dated July 27, 2017, the applicant revised LRA Sections A.2.1.5 and A.3.1.5 to incorporate aspects of the UFSAR summary description issued in LR-ISG-2015-01 that were not included in the April 28, 2017, submittal.

The staff finds the applicant's response acceptable because the UFSAR supplements for the Buried Piping and Tanks Inspection Program, as amended by letter dated July 27, 2017, are consistent with the corresponding program description in SRP-LR Table 3.0-1, as modified by LR-ISG-2015-01. The staff's concern described in RAI 3.0.3.1.2-5 is resolved.

The staff also noted that the applicant committed to revise the Buried Piping and Tanks Inspection Program to incorporate the changes shown in LRA Sections A.2.1.5 and A.3.1.5 of the letter dated July 27, 2017, by December 31, 2017.

The staff finds that the information in the UFSAR supplement, as amended by letter dated July 27, 2017, is an adequate summary description of the program.

Conclusion. On the basis of its review of the Buried Piping and Tanks Inspection Program, and the applicant's responses to RAIs 3.0.3.1.2-1, 3.0.3.1.2-2, 3.0.3.1.2-3, 3.0.3.1.2-4, and 3.0.3.1.2-5, the staff finds that those program elements for which the applicant claimed consistency with LR-ISG-2015-01 are consistent. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis (CLB) for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.3 Containment Leak Rate Program

Summary of Technical Information in the Application. By letter dated May 31, 2017 (ADAMS Accession No. ML17159A512), the applicant revised LRA AMP B.1.7, "Containment Leak Rate Program," common to IP2 and IP3, in response to the NRC staff's request to verify its ongoing consistency, with exceptions to GALL Report AMP XI.S4, "10 CFR Part 50, Appendix J" (ADAMS Accession No. ML17180A503). The revised AMP implements 10 CFR Part 50 Appendix J, Option B, through the Nuclear Energy Institute NEI 94-01 Revision 2-A, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," subject to conditions specified in the SERs for Indian Point Energy Center (IPEC) License Amendments 283 and 252 to the IP2 and IP3 facility operating licenses (ADAMS Accession Nos. ML15349A794 and ML15028A308), delineated in the updated program description and exceptions to the “monitoring and trending” and “corrective actions,” program elements. The applicant’s letter also included the site-specific IPEC “Primary Containment Leakage Rate Testing (Appendix J) Program Plan.”

Staff Evaluation. The staff reviewed the stated exceptions to “monitoring and trending” and “corrective actions” program elements in accordance with Section 3.0.1, “Background on the Types of Reviews,” of the SRP-LR, Revisions 1 and 2, which state “exceptions are portions of the GALL Report AMP that the applicant does not intend to implement,” and that “any exception … should be described and justified.” Consequently, the staff reviewed the technical justifications for the exceptions addressing portions of the “monitoring and trending” and “corrective actions” program elements, including associated operating experience from the applicant’s submitted license amendment requests and their supplements, as well as information gleaned from the IPEC Appendix J Program Plan, to assess whether the revised LRA AMP B.1.7 is adequate to manage the effects of aging for systems, structures, or components (SSCs).

Exception 1. The revised LRA Section B.1.7 states an exception to the “monitoring and trending” program element. In this exception, the applicant stated it implements 10 CFR Part 50, Appendix J through NEI 94-01 Revision 2-A, instead of NEI 94-01 Revision 0, as endorsed by Regulatory Guide (RG) 1.163, “Performance-Based Containment Leak-Test Program.” The staff reviewed this exception to AMP B.1.7, “monitoring and trending,” program element against the corresponding program element in GALL Report AMP XI.S4. The staff noted that, while NEI 94-01 Revision 0 limits the testing frequency of integrated leak rate tests (ILRTs) to a minimum of once in 10 years, NEI 94-01 Revision 2-A extends the ILRT frequency to once in 15 years, subject to specified limitations and conditions. The regulatory positions set forth in RG 1.163, endorsing NEI 94-01 Revision 0, are still applicable and are incorporated within NEI 94-01 Revision 2-A.

The “monitoring and trending” program element states that “the entire pressure boundary is monitored over time to the end of [the] period of extended operation.” ILRTs over that period continue to be supplemented with visual examinations of interior and exterior surfaces of the containment to identify potential structural deteriorations affecting containment leak-tight integrity through AMP B.1.8, “Containment Inservice Inspection (ISI) Program,” which implements ASME Code Section XI, Subsections IWE and IWL. Every 2 years, IP2 also performs visual inspections of containment external structural surfaces, containment penetrations, and hatches (ADAMS Accession No. ML15149A139).

To help further identify age-related degradation, IP2 and IP3 monitor the pressure boundary integrity against leakage of radioactive fluids to the environment through two continuous leakage limiting systems, the weld channel and penetration pressurization system (WC&PPS) (see Section 3.6.10 of the IP2 and IP3 final safety analysis reports (FSARs)) and the isolation valve seal water (IVSW) system. The WC&PPS monitors the leak tight integrity of double penetration barriers, the space between selected containment isolation valves (CIVs), air lock door seals, and most containment weld seams. The IVSW system seals certain CIV leakage paths. Its performance is monitored and verified through testing at each refueling outage.

Some remotely controlled CIVs subject to 10 CFR Part 50 Appendix J local leak rate testing (LLRT) are tested during instrumentation and controls calibrations noted in the Appendix J

Program Plan. Other pressure-retaining boundary components not subject to LLRTs but also identified in the Appendix J Program Plan (e.g., WC&PPS valves and 1-inch diameter instrument lines) are still age managed. For such components that have been excluded from LLRTs, the effects of aging are monitored through AMPs identified in LRA Tables 3.x.2-y for IP2 and IP3 ("x" indicates the table number from the GALL Report and "y" the applicable system table number), so that there is reasonable assurance that these components will function adequately between ILRTs during the period of extended operation. The effects of aging for IP2 and IP3 containment penetrations are monitored through AMP B.1.11, "External Surfaces Monitoring," as noted in LRA Section 3.2.2.1.5, and evaluated in Section 3.0.3.2.5 of this SER and its supplements.

The staff finds the exception to the "monitoring and trending," program element acceptable because NEI 94-01 Revision 2-A, as implemented by the applicant, aligns LRA AMP B.1.7 with the IP2 and IP3 technical specifications (TS) and provides reasonable assurance of adequate monitoring of the containment pressure boundary for potential aging effects, consistent with 10 CFR 54.4(a)(3) and GALL Report, Revision 2. The staff finds, for the purpose of monitoring and trending age-related degradation of the containment pressure boundary, implementation of NEI 94-01 Revision 2-A does not change the quality and intent of the "monitoring and trending" program element.

Exception 2. The revised LRA Section B.1.7 states an exception to the "corrective actions" program element. In this exception, IPEC will apply the provisions of NEI 94-01 Revision 2-A, subject to the conditions specified in the SER for the respective IP2 and IP3 license amendments. The program element in GALL Report AMP XI.S4, Revision 1, states that "[c]orrective actions are taken in accordance with 10 CFR Part 50, Appendix J, and NEI 94-01." Corrective actions include those directly associated with leakage rate tests as well as those resulting from required inspections and other supplemental examinations, noted above in Exception 1. The NRC-approved license amendment requests and their supplements referenced in the May 31, 2017, letter discuss corrective actions taken to repair liner caulking, missing/loose attachments and rusting/peeling paint, or further inspect/evaluate potential deficiencies in electrical penetrations, none of which affected the structural and leak tight integrity of the containments. Documenting these conditions through condition reports indicates that the IPEC Corrective Action Program, through evaluations performed or corrective actions taken, provides reasonable assurance of the leak tight integrity of the containment pressure boundary. The staff therefore concludes for the purpose of corrective actions, implementation of NEI 94-01 Revision 2-A does not change the quality and intent of the "corrective actions" program element.

Based on the above review of the exceptions associated with the "monitoring and trending" and "corrective actions" program elements and their justifications, the staff finds that LRA AMP B.1.7, with exceptions to GALL Report AMP XI.S4, is adequate to manage the applicable aging effects.

UFSAR Supplement. The UFSAR supplement in LRA Sections A.2.1.6 and A.3.1.6 for the Containment Leak Rate Program were amended by letter dated May 31, 2017. The staff reviewed these revised sections and determined that the information in the updated UFSAR supplements are adequate summary descriptions of the program, consistent with the recommended description in SRP-LR Table 3.0-1, "FSAR Supplement for Aging Management of Applicable Systems," as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Containment Leak Rate Program, as amended by letter dated May 31, 2017, the staff concludes that the program elements for which the applicant claimed consistency with the GALL Report AMP XI.S4 are consistent. In addition, the staff reviewed the exceptions and justifications and confirmed that AMP B.1.7, with exceptions, is adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the revised UFSAR supplement for AMP B.1.7 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. By letter dated December 16, 2014 (ADAMS Accession No. ML14365A069), the applicant responded to RAI 3.0.3-1, which addressed issues related to recurring internal corrosion in LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Tanks, and Corrosion Under Insulation." The applicant provided additional information that included two enhancements to the Service Water Integrity Program. Based on the applicant's response regarding minor corrosion issues in the service water system, the staff performed independent reviews of program-related, plant-specific operating experience that had occurred since the issuance of the initial SER in November 2009 (ADAMS Accession Nos. ML093170451 and ML093170671). During these additional reviews, the staff identified instances where loss of material and flow blockage due to fouling in the service water system resulted in safety system functional failures. The plant-specific operating experience caused the staff to question the effectiveness of some aspects of the AMP. Consequently, the staff took a number of actions (i.e., issuing RAIs, conducting onsite audits, holding a management telephone conference, and conducting a public meeting) to better understand and evaluate the extent and significance of age-related degradation in the service water system. In its responses to the staff's actions, IPEC provided additional information and committed to implement a number of enhancements to the Service Water Integrity Program. Details related to the associated issues are discussed below.

Staff Evaluation. The staff reviewed the following plant-specific licensee event reports (LERs), relating to service water system components that involved inoperable equipment or safety system functional failures due to leaks:

- LER 247/2011-003, Technical Specification (TS) violation for Entry into TS 3.0.3 for 3 Inoperable Fan Cooler Unit Trains and Failure to Correct Condition within 1 Hour and Actions Taken for Plant Shutdown

- LER 286/2011-003, Technical Specification Shutdown and a Safety System Functional Failure for a Leaking Service Water Pipe Causing Flooding in the Service Water Valve Pit Preventing Access to Accident Mitigation

- LER 247/2013-004, Technical Specification Prohibited Condition Due to an Inoperable Essential Service Water Header as a Result of Pin-Hole Leaks in Code Class 3 Service Water Piping

- LER 286/2014-002, Technical Specification Prohibited Condition Due to an Inoperable Essential Service Water Header as a Result of Socket Weld Leak in Code Class 3 Service Water Piping

- LER 247/2015-001, Technical Specification Prohibited Condition Due to an Inoperable Containment Caused by a Service Water Pipe Leak with a Flaw Size that Results in Exceeding the Allowed Leakage Rate for Containment

- LER 247/2015-004, Safety System Functional Failure Due to an Inoperable Containment Caused by a Flawed Elbow in the 21 Fan Cooler Unit Service Water Motor Cooling Return Pipe

- LER 286/2016-001, Safety System Function Failure Due to an Inoperable Containment Caused by a Flaw on the 31 Fan Cooler Unit Service Water Return Coil Line Affecting Containment Integrity

- LER 247/2016-010, Safety System Functional Failure Due to an Inoperable Containment Caused by a Through Wall Defect in a Service Water Supply Pipe Elbow to the 24 Fan Cooler Unit

Based on its reviews, the staff issued additional RAIs on May 4, 2015 (ADAMS Accession No. ML15071A101); July 25, 2016 (ADAMS Accession No. ML16138A194); and March 8, 2017 (ADAMS Accession No. ML17046A231); conducted two onsite audits (February 23-25, 2016 (ADAMS Accession No. ML16133A459) and August 1-3, 2017 (ADAMS Accession No. ML17250A244)); held a management telephone conference on May 10, 2016 (ADAMS Accession No. ML16133A499); and conducted a public meeting on October 4, 2016 (ADAMS Accession No. ML16281A216). The applicant responded to the staff's RAIs and audit activities by letters dated August 18, 2015 (ADAMS Accession No. ML15236A017); December 2, 2016 (ADAMS Accession No. ML16350A005); May 8, 2017 (ADAMS Accession No. ML17132A175); June 27, 2017 (ADAMS Accession No. ML17187A140); December 14, 2017 (ADAMS Accession No. ML17360A158); December 21, 2017 (ADAMS Accession No. ML17363A213); and February 26, 2018 (ADAMS Accession No. ML18064136). The applicant's responses resulted in the following changes and enhancements to its Service Water Integrity Program:

By letter dated December 2, 2016, in its response to RAI 3.0.3-10 Request 3, the applicant modified the associated program description in LRA Section B.1.34 by clarifying that intake bay silt-level monitoring is included in the Service Water Integrity Program. The applicant stated that the silt mapping is performed at 3-month intervals in the IP2 and IP3 service water bays, and full desilting and debris removal from the service water bays are performed (based on pump column design differences) every 4 years at IP2 and every 10 years at IP3. The staff noted that the applicant changed the silt-level monitoring activities as part of the corrective actions from an IP2 silting event in 2007 and LER 247/2011-003, and the changes address higher short-term silting rates and long-term chronic silt accumulations in the service water intake bays. The staff confirmed, during its August 2017 audit, that the current program procedures include these requirements.

The applicant proposed enhancements to the Service Water Integrity Program by letters dated December 16, 2014; December 2, 2016; May 8, 2017; December 14, 2017; and December 21, 2017. The various enhancements are delineated in Commitment No. 51 of each letter's Attachment 3, "IPEC List of Regulatory Commitments." The staff's evaluation of these enhancements follows.

Enhancement 1. By letter dated December 16, 2014, the applicant committed to enhance the "detection of aging effects" program element by revising the program procedures to evaluate through-wall leakage under the corrective action program, including operability assessments of structural integrity and determinations of appropriate corrective actions. In addition, the applicant committed to internally inspect the accessible portions of the buried safety-related service water piping once during the first 10 years of the period of extended operation.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M20 and finds it acceptable, because the evaluation of through-wall leakage using the applicant's corrective action program can ensure that feedback from operating experience results in appropriate enhancements to the existing program. In addition, internal visual inspections of service water piping can identify missing cement lining and biological growth, which can serve as a precursor to corrosion of the piping or weld metal.

Enhancement 2. By letter dated December 2, 2016, as revised by letter dated December 14, 2017, the applicant committed to enhance the "detection of aging effects" program element by revising the program procedures to: (a) perform a minimum of 25 volumetric inspections each refueling outage for each unit, (b) calculate the remaining service life of any degraded piping area returned to service and re-examine the piping prior to the end of the calculated life, (c) require a minimum of five additional volumetric weld examinations for through-wall leaks in any in-scope nonsafety-related service water piping, (d) increase the frequency of internal robotic inspections to include once during the second 10 years of the period of extended operation, (e) identify areas where leaks in nonsafety-related service water piping could cause unacceptable flooding and specify volumetric examination of 20 percent of the welds (up to a maximum of 25), during each 10-year period, (f) specify a yearly operating experience review to identify any effects of aging reported on the service water system including conditions related to inadequate cement liner repairs, (g) include guidance for lay-up of the service water process radiation monitoring system to minimize stagnant conditions, and (h) increase the flushing of stagnant vent and drain piping if the established goals for recurring internal corrosion are not met.

The staff reviewed the changes for this enhancement against the corresponding program element in GALL Report AMP XI.M20 and the guidance in SRP-LR Section A.1.2.3.10, "Operating Experience." The staff finds the enhancement acceptable, because (a) performing 25 volumetric inspections each outage for each unit represents an appropriate, substantial increase over programs that perform a comparable number of inspections over a 10-year period for units where recurring internal corrosion has not been identified; (b) using the calculated remaining service life can effectively identify the timing for subsequent inspections; (c) requiring five additional volumetric examinations for any leaking in-scope, nonsafety-related piping provides comparable corrective actions as leaking safety-related piping; (d) including additional internal robotic inspections during the second 10 years of the period of extended operation provides continued assurance of ongoing inspection activities; (e) identifying areas and examining nonsafety-related piping where leaks can cause unacceptable flooding provides appropriate consideration for additional inspection locations; (f) specifying layup guidance can be an effective mitigation technique; and (g) establishing goals for increased flushing of vent and drain piping appropriately considers operating experience feedback to adjust the program preventive actions.

Enhancement 3. By letter dated May 8, 2017, the applicant committed to enhance the "detection of aging effects" program element by prioritizing future inspections based on plant areas susceptible to flooding. The staff reviewed the change for this enhancement against the corresponding program element in GALL Report AMP XI.M20 and the guidance in SRP-LR Section A.1.2.3.10. The staff finds the enhancement acceptable, because prioritizing inspections in areas susceptible to flooding reflects feedback to address the previous plant-specific operating experience for safety system functional failures caused by flooding.

Enhancement 4. By letter dated May 8, 2017, the applicant committed to enhance the "acceptance criteria" program element by revising the program procedures to include structural integrity and leakage acceptance criteria. The acceptance criteria will include the flaw location and will include acceptance curves for flaw sizes to meet structural integrity versus pipe size and curves for flaw sizes to meet containment integrity versus leak location.

The staff noted that LERs 247/2015-001, 247/2015-004, and 286/2016-001 document leaks in service water piping inside containment that resulted in the containment being declared inoperable. The staff reviewed the change for this enhancement against the corresponding program element in GALL Report AMP XI.M20 and finds it acceptable, because the revised program will clearly establish acceptance criteria for leaks in containment that address previous plant-specific operating experience.

Enhancement 5. By letter dated May 8, 2017, the applicant committed to enhance the "corrective actions" program element by revising the program procedures to conduct a 100 percent internal lining visual inspection of the IP2 3-inch fan cooler unit spool pieces when removed during fan cooler preventive maintenance activities. The staff noted that LER 247/2016-010 documents a service water system leak, caused by defective internal lining that resulted in the containment being declared inoperable. The staff reviewed the change for this enhancement against the corresponding program element in GALL Report AMP XI.M20 and the guidance in SRP-LR Section A.1.2.3.10. The staff finds the enhancement acceptable, because liner inspections can detect areas potentially susceptible to loss of material and the change reflects feedback to address a previous safety system functional failure of containment caused by a leak in the service water system.

Enhancement 6. By letter dated May 8, 2017, the applicant committed to further enhance the "corrective actions" program element by revising the program procedures to perform a formal review of leaks that cause a loss of function. The enhancement includes identifying the cause of the leak to determine if a new aging mechanism is found and whether the AMP remains adequate. The staff reviewed the change for this enhancement against the corresponding program element in GALL Report AMP XI.M20 and the guidance in SRP-LR Section A.1.2.3.10. The staff finds the enhancement acceptable, because the change formalizes the feedback process for operating experience where the program did not successfully manage aging degradation before a loss of intended function.

Enhancement 7. By letter dated December 14, 2017, as modified by letter dated December 21, 2017, the applicant committed to enhance the "detection of aging effects" program element by revising the program procedures to: (a) perform a minimum of 25 volumetric nondestructive examinations (NDEs) each refueling interval for each unit (note that this changed the inspection quantity given in the December 2, 2016, letter and is addressed above in Enhancement 2); (b) inspect 20 percent, up to a maximum of 25, during each 10-year operating interval, of the carbon-fiber wrapped welds in the service water strainer pit using volumetric NDEs such as radiography; (c) perform internal visual inspections of 20 percent, up to a maximum of 25, during each 10-year operating interval, of the dissimilar-metal flanged connections (without galvanic insulating kits) involving carbon steel in contact with AL-6XN, Avesta 254 SMO, or 300 series stainless steel and perform follow-up volumetric inspections if appreciable localized corrosion beyond a normal oxide layer is identified (e.g., local wastage); (d) inspect 20 percent, up to a maximum of 25, during each 10-year operating interval, of the piping welds made of 904L material; and (e) require five extent-of-condition inspections whenever wall thicknesses projected to the end of the period of extended operation are calculated to be less than the specified minimum allowable wall thickness unless the component's configuration does not support volumetric NDE methods (e.g., socket welds).

The staff reviewed the change for this enhancement against the corresponding program element in GALL Report AMP XI.M20 and the guidance in SRP-LR Section A.1.2.3.10. The staff finds the enhancement acceptable, because (a) performing 25 volumetric inspections each outage for each unit represents an appropriate, substantial increase over programs that perform a comparable number of inspections over a 10-year period for units where recurring internal corrosion has not been identified; (b) performing volumetric inspections of 20 percent (up to a maximum of 25 locations) of the carbon fiber wrapped welds in the service water strainer pit, appropriately compensates for the lack of visual leakage detection resulting from the installation of the carbon fiber wrap; (c) performing visual inspections of 20 percent (up to a maximum of 25 locations) of dissimilar-metal flanged connections with a focus on the components most susceptible to galvanic corrosion appropriately adjusts inspections to leading and bounding locations; (d) inspecting 20 percent of the 904L welds during each 10-year period implements appropriate corrective actions as noted in LER 286/2016-001; and (e) requiring five extent of condition inspections if wall thicknesses projected to the end of the period of extended operation do not meet the specified minimum wall thickness appropriately augments the program to account for recurring internal corrosion. The staff notes that for the full structural carbon fiber wrap installed at weld PAB-204, the applicant chose to manage the associated aging effects of the carbon fiber-reinforced epoxy through the Periodic Surveillance and Preventive Maintenance Program in lieu of using the Service Water Integrity Program. See SER Section 3.0.3.3.7 for additional discussion.

Enhancement 8. By letter dated December 14, 2017, the applicant committed to enhance the "corrective actions" program element by implementing recently developed guidelines from IP-RPT-16-00046, "IPEC Service Water Piping Weld Repair Process and Re-inspection Frequency Guidelines." The applicant stated that the document was developed to prevent recurrence of events related to inadequate repairs to service water piping welds. In addition, the applicant committed to incorporate the guidelines of IP-RPT-17-00062, regarding the evaluation of containment operability based on service water piping leak rates, into the Service Water Integrity Program procedural guidance.

Based on the staff's review of IP-RPT-16-00046 during the August 2017 audit, the staff noted that the report provides guidance for: (a) inspection and engineering personnel coordination to ensure that the NDE examination data is sufficient to characterize the extent of the defect, (b) formal calculations to determine the extent of repairs, (c) formal re-inspection guidelines when welds are repaired, (d) consideration of the impact of welding on the integrity of the pipe internal lining, and (e) standardized approaches for determining the next inspection interval. The staff notes that a cause of the leak identified in LER 286/2011-003 included an inadequate repair of a flaw identified in 1992. In addition, the staff notes that the newly developed leak rate guidelines in IP-RPT-17-00062 will establish criteria for evaluating containment operability and will provide a benchmark for the need to adjust inspections inside containment based on leaks found in comparable piping outside containment. The staff reviewed the enhancement against the corresponding program element in GALL Report AMP XI.M20 and the guidance in SRP-LR Section A.1.2.3.10. The staff finds the enhancement acceptable, because the additional guidelines in the two reports can provide for more effective weld repairs and establish future inspection requirements and frequencies.

Operating Experience. As noted in the report for the onsite audit conducted February 23-25, 2016, the staff performed an independent search of IPEC's operating experience database to assess past leakage in the service water system as it related to recurring internal corrosion. In addition, as noted in the report for the onsite audit conducted August 1-3, 2017, the staff reviewed additional operating experience reports, which in some cases documented safety system function failures. The applicant addressed issues associated with operating experience reports through its RAI responses and commitments to enhance the Service Water Integrity and the Periodic Surveillance and Preventive Maintenance AMPs. Based on its audit and review of the applicant's responses to RAIs, the staff finds that the applicant has appropriately evaluated plant-specific operating experience and implementation of the program has resulted in the applicant taking adequate corrective actions.

UFSAR Supplement. LRA Sections A.2.1.33 and A.3.1.33, as modified by letter dated December 21, 2017, provide the UFSAR supplements for the IP2 and IP3 Service Water Integrity Programs. The staff reviewed these sections and finds that the UFSAR supplements provide adequate summary descriptions of the programs and activities for managing the effects of aging, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its additional audits and reviews of the applicant's Service Water Integrity Program, the staff finds that, with the enhancements described above, the program will be adequate to manage the effects of aging. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplements for this program and concludes that they provide an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2 AMPs Consistent with the GALL Report with Exceptions or Enhancements

3.0.3.2.1 Aboveground Steel Tanks Program

Summary of Technical Information. In its response associated with the Aboveground Steel Tanks Program, the applicant stated that the revised AMP is consistent with LR-ISG-2012-12. The applicant added the aging effect of cracking and expanded the inspections to address the aging management of both the inside and outside surfaces of the tanks. The revised program also includes preventive measures to mitigate aging. An additional enhancement was added to the program that provides the inspection details for visual and surface examinations and an exception was taken to the implementation schedule for the AMP because IP2 and IP3 have entered the period of extended operation as of December 2015.

Staff Evaluation. The staff reviewed the revised versions of LRA Sections A.2.1.1, A.3.1.1, and B.1.1, which are provided in the applicant's letter dated December 16, 2014 (ADAMS Accession No. ML14365A069), to determine whether the program will be adequate to manage the aging effects for which it is credited, as discussed below.

The program was revised to state that the loss of material and cracking of the inside and outside surfaces of aboveground outdoor metallic tanks are inspected using visual and surface examinations. Additionally, volumetric inspections are performed on tanks supported on soil or concrete foundations to detect degradation in inaccessible locations. The details of the inspections are tabulated in the program description in LRA Section B.1.1 and implemented by Enhancement 3. There are no indoor tanks in the scope of license renewal. The program also credits standard industrial practices, including sealant, caulk, paint, and coating, as preventive measures. Visual examinations and physical manipulation is used to monitor the potential degradation of the preventive measures. Consistent with LR-ISG-2012-02, the program also states that (a) for tanks where the exterior surface is fully visible, that surface may be inspected under the External Surfaces Monitoring Program in lieu of the visual inspections recommended in this AMP; and (b) surface examinations are conducted in accordance with the provisions of this AMP.

For the "detection of aging effects" program element, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below:

During its review, the staff noted that plant-specific note 305, associated with steel tanks in LRA Table 3.3.2-17-IP2 exposed to an internal environment of treated water, 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." Section IX.D, "Selected Definitions & Use of Terms for Describing and Standardizing Environments," of the GALL Report, Revision 2, describes treated water as demineralized water or water containing corrosion inhibitors, and it describes raw water as water that includes potable water and water used for drinking or other personal use. The staff noted that city water appears to more closely resemble raw water as defined in the GALL Report. AMP XI.M29, "Aboveground Metallic Tanks," as amended by LR-ISG-2012-02, provides different guidance for managing loss of material for steel tanks exposed to treated water and raw water: one-time inspections may be used for steel exposed to treated water, whereas periodic inspections are recommended for steel exposed to raw water. Based on the table of inspection details included in the letter dated December 16, 2014, the city water tank will be subject to one-time inspection. By letter dated May 4, 2015 (ADAMS Accession No. ML15071A101), the staff issued RAI 3.0.3-15 requesting that the applicant justify why city water is being categorized as treated water instead of raw water.

In its response dated August 18, 2015 (ADAMS Accession No. ML15236A017), the applicant stated that city water is categorized as treated water because the aging effects resulting from material exposed to city water more closely align with those resulting from exposure to treated water than to raw water. The applicant further stated that periodic inspections were accounted for in the Periodic Surveillance and Preventive Maintenance Program originally used to manage the aging of the city water tank. The applicant revised the inspection details table of the Aboveground Steel Tanks Program in LRA Sections A.2.1.1 and B.1.1 to require periodic inspections for steel tanks exposed to "raw water (city water)." The staff's concern described in RAI 3.0.3-15 is resolved.

The staff also reviewed the portions of the response associated with exceptions and enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of the exception and enhancement follows.

Enhancement 1. Evaluated in NUREG-1930, Volume 1.

Enhancement 2. Evaluated in NUREG-1930, Volume 2.

Enhancement 3. The program will be enhanced to develop or revise program implementation documents to incorporate the inspection details tabulated in the program description. The table and table notes in the Aboveground Steel Tanks Program description are consistent with Table 4a, "Tank Inspection Recommendations," of LR-ISG-2012-02. However, the implementation schedule is not consistent with the guidance in LR-ISG-2012-02, as discussed in Exception 1. This enhancement encompasses Enhancement 1, such that Enhancement 1 is no longer applicable.

Exception 1. The response to RAI 3.0.3-1 adds an exception to the implementation schedule of the Aboveground Steel Tanks Program. The exception states that the implementation schedule for the program inspections will not be consistent with LR-ISG-2012-02 because of the timing of the issuance of the guidance. LRA Sections A.2.1.1, A.3.1.1, and B.1.1 state that the program enhancements will be implemented before December 31, 2019. The staff noted that it was unclear why inspections might not be implemented until December 31, 2019, given that IP2 and IP3 are beyond the expiration of their initial licenses. By letter dated May 4, 2015, the staff issued RAI 3.0.3-14 requesting that the applicant state the basis and justify why the implementation of the inspections might not occur until December 31, 2019.

In its response dated August 18, 2015, the applicant stated that the timing of inspections identified in LR-ISG-2012-02, Table 4a, are tied to the date a particular unit will enter the period of extended operation. The applicant also stated that for both IPEC units, the date of entering the period of extended operation was not a realistic date for implementing the program enhancements from the ISG because IP2 had already entered the period of extended operation at the time that RAI 3.0.3-1 was received and IP3 entered the period of extended operation in December 2015. The applicant also identified December 31, 2019, as a realistic implementation date to be treated in the same manner as a date for entering the period of extended operation and stated that this 5-year period allows for two outages for each unit in which to perform the specific inspections, some of which may necessitate an outage. The applicant further stated that the 5-year period would permit adequate planning and coordination of the outages, the scope of which is established many months ahead of time. The applicant listed activities to be implemented including: planning, scheduling, and completing activities in LR-ISG-2012-02; assessing the results and determining corrective actions; as well as planning and scheduling activities to be performed during the remainder of the period of extended operation. The applicant noted that where the ISG states that activities will be completed before the period of extended operation, IPEC will complete those activities prior to December 31, 2019.

The staff reviewed the information provided in regard to the program implementation schedule. The staff noted that LR-ISG-2012-02 allows 10 years prior to the period of extended operation to complete the baseline inspections recommended before entering the period of extended operation. The timeframe is intended to allow baseline inspections and the need for trained and qualified personnel. The staff also noted that the applicant will perform baseline inspections during the 5 years prior to the official implementation date of the enhancements to its Aboveground Steel Tanks Program. The staff finds the applicant's response acceptable because the applicant's program implementation schedule is consistent with guidance provided in GALL Report AMP XI.M29 and the in-scope tanks will be continuously managed prior to December 31, 2019. The staff's concern described in RAI 3.0.3-14 is resolved.

Based on its review of the applicant's responses to RAIs 3.0.3-1 and 3.0.3-14, the staff finds that the program is consistent with GALL Report AMP XI.M29, as revised by LR-ISG-2012-02, with the exception that the inspections normally conducted before the period of extended operation will be performed in the 5 years before December 31, 2019. The staff finds that the program is adequate to manage the aging effects for which it is credited.

Operating Experience. LRA Section B.1.1, as amended by letter dated December 16, 2014, summarizes additional operating experience related to the Aboveground Steel Tanks Program. The applicant stated that thickness measurements were performed on the city water tank in 2003 and showed that the tank was in good condition. The applicant also stated that thickness measurements performed on the IP2 condensate storage tank in 2008 revealed minor corrosion with no loss of intended function.

The staff reviewed operating experience information in the application, the response to RAI 3.0.3-1, and the supplemental audit, to determine whether the applicant reviewed the applicable aging effects and industry and plant-specific operating experience. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program. The staff did not identify any operating experience that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and review of the application, and review of the applicant's response to RAI 3.0.3-1, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and implementation of the program has resulted in the applicant taking adequate corrective actions. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.M29 was evaluated.

UFSAR Supplement. LRA Sections A.2.1.1 and A.3.1.1 provide the UFSAR supplements for the Aboveground Steel Tanks Program. The staff reviewed the UFSAR supplement description of the program, as amended by letters dated December 16, 2014, and August 18, 2015, and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1, as amended by LR-ISG-2012-02. The staff also noted that the applicant committed (Commitment No. 1) to implementing the revisions to LRA Sections A.2.1.1, A.3.1.1, and B.1.1. The staff finds that the information in the UFSAR supplement, as amended by letters dated December 16, 2014, and August 18, 2015, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the applicant's Aboveground Steel Tanks Program, as amended by letters dated December 16, 2014, and August 18, 2015, the staff finds that those program elements for which the applicant claimed consistency with the GALL Report, as amended by LR-ISG-2012-02, are consistent. In addition, the staff reviewed the exception and the enhancement and finds that the AMP, with the exception and the enhancement, is adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.2 Bolting Integrity Program

Summary of Technical Information. By letter dated May 18, 2017 (ADAMS Accession No. ML17143A234), the applicant enhanced its Bolting Integrity Program, in response to

RAI B.1.2-1, to address aging effects associated with in-scope closure bolting installed in components located in systems with an internal environment of a clear gas such as air or nitrogen.

Staff Evaluation. In its response, the applicant stated that it will conduct a visual inspection of a representative sample of closure bolting from components with an internal environment of clear gas, such as air or nitrogen. The visual inspection will be conducted with the bolting removed from the joint such that the bolt head, nuts, and threads will be exposed for inspection. The sample size will be 20 percent of the population up to a maximum of 25 fasteners for each bolting material and environment combination. Inspections will be conducted during each 10-year period of the period of extended operation. The applicant also stated that the enhancement will be implemented before May 31, 2018. The applicant amended LRA Sections A.2.1.2 and A.3.1.2 (UFSAR supplements for the Bolting Integrity Program) and stated a new commitment, Commitment No. 53, to address the above details. By letter dated June 25, 2018 (ADAMS Accession No. ML18183A147), the applicant confirmed that it was in the implementation phase of the enhancement, a program has been developed, and a number of potential opportunistic inspections have been selected.

The staff noted that: (a) the sample size, frequency of inspection, and inspection method is consistent with other sampling-based based programs in the GALL Report such as AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"; (b) significant loss of material or cracking would not be expected due to exposure of the closure bolting threads to an air or gas environment; (c) although this population of closure bolting will be subject to sampling for loss of preload, there are a significant number of other closure bolts installed in systems exposed to fluids that will be inspected for leakage; (d) inspections for leakage are credited by AMP XI.M18, "Bolting Integrity," to detect loss of preload; and (e) loss of preload is mitigated by the applicant's preventive actions (e.g., use of EPRI standards associated with closure bolting) for all in-scope closure bolting.

The staff finds the applicant's response to RAI B.1.2-1 and the changes to the Bolting Integrity Program adequate because: (a) sampling-based inspections are acceptable to detect loss of material or cracking because it is not expected that the internal environment would cause these aging effects; (b) due to the extensive number of inspections to detect loss of preload, the applicant will be adequately informed of the potential for loss of preload to occur; and (c) based on the implementation date of Commitment No. 53, inspections will be completed in the first 10-year period of extended operation and continue in the next 10-year interval, consistent with AMP XI.M18.

On the basis of its review of changes to the applicant's Bolting Integrity Program, the staff concludes that the applicant has demonstrated that the effects of aging associated with in-scope closure bolting installed in components located in systems with an internal environment of a clear gas such as air or nitrogen will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplements for this AMP and concludes that they provide an adequate summary description of the programs, as required by 10 CFR 54.21(d).

3.0.3.2.5 External Surfaces Monitoring Program

Summary of Technical Information in the Application. The staff's evaluation of the External Surfaces Monitoring Program before the issuance of the applicant's responses to RAI 3.0.3-1 is documented in NUREG-1930, Section 3.0.3.2.5. As amended by letter dated December 16, 2014 (ADAMS Accession No. ML14365A069), the applicant added an additional enhancement and revised LRA Sections A.2.1.10, A.3.1.10, and B.1.11 and Commitment No. 5 to address LR-ISG-2012-02, CUI for steel, stainless steel, and copper-alloy components exposed to outdoor air and condensation.

Enhancement 2. As amended by letter dated December 16, 2014, the applicant committed to implement the following enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that it will revise its procedures for inspecting insulated components. The changes encompass the recommendations addressing CUI in LR-ISG-2012-02, AMP XI.M36, "External Surfaces Monitoring of Mechanical Components."

The staff reviewed the enhancement and finds it acceptable because implementation of the enhancement will result in periodic visual inspections being performed on a representative sample of insulated components based on the likelihood of CUI occurring, which is consistent with the GALL Report AMP XI.M36, as modified by LR-ISG-2012-02.

UFSAR Supplement. As amended by letter dated December 16, 2014, in LRA Sections A.2.1.10 and A.3.1.10, the applicant provided the UFSAR supplements for the External Surfaces Monitoring Program. The staff reviewed these sections and determined that the information in the UFSAR supplements is an adequate summary description of the program, consistent with LR-ISG-2012-02, SRP-LR Table 3.0-1, as required by 10 CFR 54.21(d).

As amended by letter dated December 16, 2014, the applicant revised Commitment No. 5. The commitment states that IP2 and IP3 will implement LRA sections pertaining to the External Surfaces Monitoring Program. As documented in LRA Sections A.2.1.10, A.3.1.10, and B.1.11, the applicant has committed to enhance this program prior to December 31, 2019.

Conclusion. On the basis of its review of the applicant's External Surfaces Monitoring Program, the staff has determined that those program elements for which the applicant claimed consistency with LR-ISG-2012-02, AMP XI.M36, are consistent. In addition, the staff reviewed the enhancements and confirmed that their implementation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplements for this AMP and concludes that they provide an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.8 Fire Water System Program

The Fire Water System Program and associated UFSAR supplements have been revised to address loss of material due to recurring internal corrosion. The staff's evaluation of these changes is documented in SER Section 3.0.3.4.1.

3.0.3.2.14 Steam Generator Integrity Program

The following safety evaluation supplements the staff's evaluation regarding the Steam Generator Integrity Program (LRA Section B.1.35) that is documented in Section 3.0.3.2.14 of NUREG-1930, Volume 2, November 2009 (ADAMS Accession No. ML093170671).

Summary of Technical Information. The summary of the technical information for the applicant's Steam Generator Integrity Program is as documented in the "Summary of Technical Information in the Application" subsection in Section 3.0.3.2.14 of NUREG-1930, Volume 2, with the following update.

By letter dated January 17, 2017 (ADAMS Accession No. ML17023A209), the applicant informed the staff that it took certain actions regarding Commitment Nos. 41 and 42 based on the new guidance in LR-ISG 2016-01, "Changes to Aging Management Guidance for Various Steam Generator Components," dated December 7, 2016. SER Sections 3.1.2.1 and 3.1.2.2.16 document the staff's evaluations of the applicant's actions regarding Commitment Nos. 41 and 42, respectively. The applicant also indicated that its aging management for steam generator components is consistent with the updated guidance in LR-ISG-2016-01.

Staff Evaluation. The staff's evaluation of the applicant's program is as documented in the "Staff Evaluation" subsection in Section 3.0.3.2.14 of NUREG-1930, Volume 2, with the following update.

As discussed above, the applicant's letter dated January 17, 2017, indicates that certain actions were taken with respect to Commitment Nos. 41 and 42 in accordance with LR-ISG-2016-01. The applicant's letter also indicates that, since the industry analyses (EPRI Report 3002002850) referenced in LR-ISG-2016-01 are bounding for the applicant's steam generators, the applicant uses the new guidance in LR-ISG-2016-01 to manage the aging effect due to primary water stress corrosion cracking (PWSCC) for divider plate assemblies and tube-to-tubesheet welds. The staff's evaluations of the applicant's actions related to Commitment Nos. 41 and 42 are documented in SER Sections 3.1.2.1 and 3.1.2.2.16, respectively.

As the applicant's letter notes, LR-ISG-2016-01 provides updated guidance for AMPs and activities for steam generator components. Specifically, LR-ISG-2016-01 includes the following guidance on aging management for steam generator components.

- Visual inspections: steam generator head internal areas are inspected to identify signs of cracking or loss of material (e.g., rust stains and distortion of divider plates). GALL Report AMP XI.M19, "Steam Generators," is revised to include these visual inspections.
- Frequency of the visual inspections: at least every 72 effective full-power months or every third refueling outage, whichever results in more frequent inspections.
- Implementation of the recent EPRI steam generator guidelines, including (a) EPRI Report 1022832 (primary-to-secondary leak guidelines); (b) EPRI Report 1025132 (in-situ pressure test guidelines); (c) EPRI Report 3002007571 (integrity assessment guidelines); and (d) EPRI Report 3002007572 (examination guidelines).

In its letter dated January 17, 2017, the applicant indicated that its aging management for steam generator components is consistent with the updated guidance in LR-ISG-2016-01. However, the staff concluded that there was insufficient information to determine whether the applicant's program is consistent with the guidance in LR-ISG-2016-01 discussed above.

By letter dated April 19, 2017 (ADAMS Accession No. ML17088A327), the staff issued RAI B.1.35-2 requesting that the applicant provide additional information to demonstrate that the Steam Generator Integrity Program is consistent with the guidance discussed above. The staff also requested that, if the program is not consistent with the guidance, the applicant provide justification for why the applicant's program is adequate for aging management. In addition, the staff requested that the applicant provide an updated description of the UFSAR supplement for the Steam Generator Integrity Program as necessary.

In its response dated May 19, 2017 (ADAMS Accession No. ML17145A288), the applicant indicated that, during the IP3 spring 2017 refueling outage, general visual inspections were performed on the steam generator channel heads, divider plater assemblies and tube-to-tubesheet welds in all four steam generators, consistent with LR-ISG-2016-01. The applicant also indicated that the visual inspections did not reveal any rust stains or abnormal conditions such as distortion of divider plates. The applicant further indicated that a similar inspection was planned for the spring 2018 refueling outage of IP2.

In addition, the applicant identified an enhancement to the "detection of aging effects" program element. In this program enhancement, the applicant indicated that it will revise applicable procedures to specify a general visual inspection of the steam generator channel head (Commitment No. 54), consistent with LR-ISG-2016-01. The applicant further stated that this enhancement would be implemented by December 31, 2017.

By letter dated June 25, 2018 (ADAMS Accession No. ML18183A147), the applicant confirmed that a similar inspection was performed for IP2 and that the steam generator program procedures have been revised to specify a general visual inspection of the steam generator channel head.

With respect to the frequency of the general visual inspections, the applicant indicated that at IP2 the visual inspection will be performed at least once every 48 effective full-power months and at IP3 the visual inspection will be performed at least once every 72 effective full-power months (which is every third refueling outage), consistent with the guidance in LR-ISG-2016-01. The applicant also clarified that this inspection frequency for each unit is consistent with the minimum inspection frequency for steam generator tubes specified in the TS. The applicant further confirmed that it continues to implement the EPRI steam generator guidelines within the timeframes required by the EPRI Steam Generator Management Program (SGMP) in accordance with NEI 97-06, Revision 3.

In addition, the applicant provided relevant revisions to LRA Sections B.1.35 (program description), A.2.1.34 (IP2 UFSAR supplement) and A.3.1.34 (IP3 UFSAR supplement) for the Steam Generator Integrity Program.

In its review, the staff found the applicant's response acceptable because (1) the applicant already performed general visual inspections on all four steam generator channel heads at IP3, as recommended in LR-ISG-2016-01, and the inspections did not reveal any rust stains or other abnormal conditions indicating cracking or loss of material; (2) the applicant clarified that the frequency of the visual inspections at each unit is consistent with the guidance in LR-ISG-2016-01; (3) the applicant confirmed that it continues to implement the EPRI steam generator guidelines in accordance with the industry-specified implementation schedules; (4) the applicant identified an adequate program enhancement to revise procedures for implementation of the visual inspections described in LR-ISG-2016-01; (5) these inspections can identify signs (e.g., rust stains, gross cracking, distortion of divider plates, and cladding breach) indicating cracking due to PWSCC in divider plate assemblies and tube-to-tubesheet welds and loss of material due to boric acid corrosion in channel heads and tubesheets; and (6) these inspections can also confirm the structural integrity of reactor coolant pressure boundary (RCPB) components such as steam generator channel heads and tubesheets. The staff's concern described in RAI B.1.35-2 is resolved.

Enhancement. As discussed above, the applicant's letter dated May 19, 2017, includes an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant indicated that it would revise applicable procedures to specify a general visual inspection of the steam generator channel head (Commitment No. 54). As previously discussed, the staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M19, as revised in LR-ISG-2016-01, and finds it acceptable because when it is implemented it will establish implementation procedures to perform general visual inspections of steam generator channel heads, consistent with the guidance in LR-ISG-2016-01.

In its letter dated May 19, 2017, the applicant also confirmed the completion of the previous enhancement (Commitment No. 24) to revise 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 staff noted that the applicant adequately updated the commitment status based on the completion of the previous program enhancement and associated commitment.

<u>Operating Experience</u>. The staff's evaluation of the operating experience for the applicant's Steam Generator Tube Integrity Program is as documented in the "Operating Experience" subsection in Section 3.0.3.2.14 of NUREG-1930, Volume 2.

<u>UFSAR Supplement</u>. The staff's evaluation of the UFSAR supplement for the applicant's Steam Generator Tube Integrity Program is as documented in the "UFSAR Supplement" subsection in Section 3.0.3.2.14 of NUREG-1930, Volume 2, with the following update.

As discussed above, the applicant's letter dated May 19, 2017, provides adequate revisions to LRA Sections A.2.1.34 (IP2 UFSAR supplement) and A.3.1.34 (IP3 UFSAR supplement) for the Steam Generator Integrity Program, including the general visual inspections, consistent with LR-ISG-2016-01. The staff reviewed the UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1, as revised in LR-ISG-2016-01. The staff finds that the information in the UFSAR supplement, as amended by letter dated May 19, 2017, is an adequate summary description of the program.

<u>Conclusion</u>. On the basis of its audit and review of the applicant's Steam Generator Tube Integrity Program, the staff determined that the program elements are consistent with those in the GALL Report, as updated in LR-ISG-2016-01. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained in a way consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). In addition, the staff reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d)

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

3.0.3.3.7 Periodic Surveillance and Preventive Maintenance

<u>Summary of Technical Information in the Application</u>. The applicant provided additional information related to the Periodic Surveillance and Preventive Maintenance Program in its responses to issues associated with the Service Water Integrity Program and recurring internal corrosion in the city water system. The staff's evaluation of the changes to the program and associated UFSAR supplements for issues in the city water system is documented in SER Section 3.0.3.4.1.

By letters dated December 14, 2017 (ADAMS Accession No. ML17360A157), and February 26, 2018 (ADAMS Accession No. ML18064A136), the applicant added new program activities to visually inspect the carbon fiber reinforced epoxy overlay on service water system line 405 each operating cycle to manage cracking, blistering, and loss of material. In addition, the applicant added a new one-time volumetric examination of line 405 (to be performed at the same location where the minimum wall thickness was found in 2015) to confirm that the degradation rate of the underlying carbon steel piping will not result in exposure of the internal surface of the carbon fiber reinforced epoxy to raw water during the renewed license term.

By letter dated December 14, 2017, the applicant amended LRA Section A.2.1.28, "Periodic Surveillance and Preventive Maintenance," by adding the chlorination system to the list of systems that will use the Periodic Surveillance and Preventive Maintenance Program to manage the effects of aging.

<u>Staff Evaluation</u>. The staff reviewed the applicant's proposed changes to the program as discussed above. The staff notes that degradation of the carbon fiber reinforced epoxy coating (i.e., cracking, blistering, and loss of material) can be adequately identified through the proposed periodic visual inspections. In addition, the verification of the underlying carbon steel corrosion rate through a one-time volumetric inspection conducted in 2021 will provide reasonable assurance that the internal surface of the carbon fiber reinforced epoxy coating will not be exposed to raw water. Consequently, the internal surface of the epoxy coating will not have any AERMs. In addition, the staff finds the addition of the chlorination system to the Periodic Surveillance and Preventive Maintenance Program description acceptable because the staff reviewed the components within the chlorination system and found components (gray cast iron valve bodies and piping) that are similar to other components already being managed for aging (loss of material) by the Periodic Surveillance and Preventive Maintenance Program.

The staff finds the applicant's proposed changes to the Periodic Surveillance and Preventive Maintenance Program acceptable because the periodic visual inspections of the epoxy coating can adequately identify external degradation of the epoxy overlay material. In addition, a one-time inspection to confirm the corrosion rate of the underlying carbon steel provides reasonable assurance that the internal surface of the external epoxy coating will not have AERMs.

<u>Operating Experience</u>. There are no changes or updates to this SER section.

<u>UFSAR Supplement</u>. In LRA Section A.3.1.28, as modified by letter dated December 14, 2017, the applicant provided the UFSAR supplement for the IP3 Periodic Surveillance and Preventive Maintenance Program. The staff notes that the applicant will implement the changes described in LRA Section B.1.29, as documented in Commitment No. 21, by December 31, 2018. The staff reviewed this UFSAR supplement description of the program and finds it to be an adequate summary description of the program.

<u>Conclusion</u>. On the basis of its additional reviews 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).

3.0.3.3.9 Reactor Vessel Internals

By letter NL-17-020 dated February 6, 2017 (ADAMS Accession No. ML17047A541), the applicant submitted a revision to the Reactor Vessel Internals Aging Management Program. The revised reactor vessel internals (RVI) AMP is LRA Section B.1.42, “Reactor Vessel Internals Program.” The staff’s review of the revised AMP was limited to the changes from the previous version of the AMP, which was submitted via letter dated February 17, 2012 (ADAMS Accession No. ML12060A312), and approved in Supplement 2 to the Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3 (SSER 2), dated July 31, 2015 (ADAMS Accession No. ML15188A383). Under “Program Description,” the revised RVI AMP included a paragraph discussing license renewal interim staff guidance in LR-ISG-2011-04, which updated the RVI AMP in the GALL Report, Revision 2, to be consistent with Materials Reliability Program (MRP)-227-A. This change is acceptable because LR-ISG-2011-04 is the latest NRC guidance for PWR RVI AMPs, and was used by the staff as the review guidance in the NRC’s review of the previous revision of the applicant’s RVI AMP in SSER 2.

Under attribute 10, “Operating Experience,” the applicant added a summary of the 2016 operating experience with baffle-former bolt (BFB) examination and replacement at IP2. The summary indicates that the applicant performed the initial (baseline) ultrasonic testing (UT) examination of 100 percent of accessible BFBs in accordance with MRP-227-A during the spring 2016 refueling outage. A total of 227 potentially degraded BFBs were identified, including BFBs with visual signs of failure, BFBs with UT indications, and BFBs inaccessible for examination. Entergy replaced all 227 potentially degraded BFBs, plus 51 additional BFBs to reduce the probability of future failures and to minimize the probability of clusters of failed bolts. The applicant indicated that as a result of the IP2 results, Westinghouse issued Nuclear Safety Advisory Letter (NSAL) 16-01 recommending Westinghouse 4-loop plants with a downflow configuration and Type 347 stainless steel BFBs perform the initial UT examination of all BFBs no later than the next refueling outage. In accordance with NSAL 16-1 and as a result of this operating experience, the applicant rescheduled the initial examination of the IP3 BFBs from 2019 to 2017. The applicant indicated that the rescheduled examination for IP3 also complies with EPRI MRP Letter 2016-022, “Transmittal of NEI-03-08, ‘Needed’ Interim Guidance Regarding Baffle Former Bolt inspections for Tier 1 Plants as Defined in Westinghouse NSAL 16-01,” dated July 27, 2016 (ADAMS Accession No. ML16211A054).

Based on its review of the changes to the applicant’s RVI AMP, the staff finds the applicant’s “operating experience” program element to be acceptable because it meets the criteria of AMR results LR-ISG-2011-04 Section XI.M16A by (1) providing for a systematic and ongoing review of plant-specific and industry operating experience, and (2) conforms to the guidance of NEI 03-08 with regard to reporting of operating experience. Further, the changes to the RVI AMP demonstrate that the applicant is taking appropriate action in response to plant-specific and industry operating experience.

On the basis of its review of the changes to the applicant’s RVI AMP, the staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the FSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.10 Reactor Vessel Internals Inspection Plan

By letter NL-17-020 dated February 6, 2017 (ADAMS Accession No. ML17047A541), the applicant submitted a revision to the "Indian Point Energy Center Reactor Vessel Internals Inspection Plan." The only significant change to the RVI Inspection Plan is the addition of a new Section 6.0, "Operating Experience and Additional Considerations." Subsection 6.2, "Spring 2016 Operating Experience," discusses the operating experience at IP2 and other similar design pressurized water reactors (PWRs) with BFB degradation. Section 6.2 states that the IPEC RVI Inspection Plan was modified as a result of this operating experience.

In Section 6.2, the applicant concluded that, based on IP2 and industry operating experience and the fractographic examination of bolts from IP2, volumetric (UT) examination of the required original bolts, and replacement of the original bolts until none of the original BFBs are required for the baffle-former assembly to perform its intended safety function, is a reasonable and acceptable approach. Section 6.2 further stated that the applicant would take the following five actions:

(a) The IP3 baffle-bolt inspections previously scheduled to be performed in Spring 2019 (3R20) will be performed in Spring 2017 (3R19) . Visual and UT inspections on 100 percent of all accessible BFBs, and a visual inspection of the baffle-edge bolts and baffle-former assembly, will be performed in 3R19.

(b) Entergy will perform a UT inspection of 100 percent of the original bolts at IP2 and IP3 during each of the subsequent refueling outages if any of the original bolts are required to remain structurally capable of carrying their design load to ensure structural integrity of the baffle structure during all design conditions.

(c) Entergy will also perform general visual inspections to identify anomalies in the baffle structure at IP2 and IP3 during each subsequent refueling outage.

(d) Entergy will perform a UT inspection of inservice replaced (new) bolts if the general visual inspections performed in accordance with paragraph c above identify degraded new bolts.

(e) Entergy will replace all bolts with indications that are needed to remain structurally capable of carrying their design load to ensure structural integrity of the baffle structure during all design conditions. Additional "good" or anti-cluster bolts will also be replaced to ensure that sufficient margin is maintained to accommodate the same failure rate until the next inspection as the failure rate identified during the current refueling outage. This margin will ensure compliance with the intent of the guidelines provided in WCAP-17096, Revision 2, "Reactor Internals Acceptance Criteria Methodology and Data Requirements."

<u>Staff Evaluation</u>. For the review of the revised RVI Inspection Plan, the scope of the staff's review was limited to the changes relative to the previous RVI Inspection Plan, which was submitted to the NRC by letter dated February 17, 2012 (ADAMS Accession No. ML12060A312). In SSER 2 (ADAMS Accession No. ML15188A383), the staff concluded that the proposed RVI Inspection Plan implements the elements of the RVI AMP in an acceptable manner. The bases for the staff's conclusion are that (1) the applicant's program is consistent with the generic RVI inspection and evaluation guidelines of Materials Reliability Program (MRP)-227-A; (2) the applicant adequately addressed all of the applicant/licensee action items (A/LAIs) of the final safety evaluation (SE) for MRP-227, Revision 0, that are applicable to Westinghouse-designed RVI or generically to all nuclear steam supply system

(NSSS) designs; and (3) the RVI Inspection Plan addresses the conditions of the final SE for MRP-227, Revision 0.

The applicant stated in Section 6.2 item 1 that it would perform the visual and UT inspections on 100 percent of the accessible BFBs and a visual inspection of baffle-edge bolts and the baffle-former assembly in 2017 for IP3. The staff notes that this examination was completed during the spring 2017 IP3 refueling outage. The staff further notes that all degraded bolts at IP3 identified by the spring 2017 examinations were replaced, as were some additional non-degraded bolts. As detailed in Section 3.0.3.3.9, IP2 has already performed initial (baseline) UT examination of BFBs in 2016, and replaced a sufficient number of BFBs to restore structural integrity.

The staff notes that the EPRI MRP issued interim guidance to MRP members on July 25, 2016, via MRP Letter 2016-021, related to examination of BFBs, which was transmitted to the NRC for information only via MRP Letter 2016-022, dated July 27, 2016 (ADAMS Accession No. ML16211A054). The interim guidance recommends UT examination no later than the next refueling outage for Westinghouse four-loop plants operating in a downflow configuration with Type 347 stainless steel BFBs, a category which includes IP2 and IP3. This recommendation was designated as NEI 03-08 “needed” guidance. The EPRI MRP issued additional interim guidance to MRP members via MRP Letter 2017-009 on March 15, 2017 (ADAMS Accession No. ML17087A106), and transmitted this additional guidance for information to the NRC on March 23, 2017 (ADAMS Accession No. ML17087A107). The new interim guidance modifies the existing entry in MRP-227-A, Revision 1, Table 4-3, for “Examination Method/Frequency” of BFBs and is classified as NEI 03-08 “needed” guidance. The new guidance reaffirms the changes to the schedule for initial UT examination of Westinghouse four-loop, downflow plants with Type 347 stainless steel BFBs such as IP2 and IP3. In accordance with the additional interim guidance, licensees of plants that find BFB degradation must determine the reinspection interval through plant-specific evaluation under MRP-227-A “needed” requirement 7.5, as documented and dispositioned by the plant corrective action program. The new guidance also imposes a 6-year maximum interval for subsequent examination for downflow plants that find 3 percent or more of the BFBs degraded during the initial UT examination.

The staff notes that the initial examinations of IP2 and IP3 have been performed on a schedule consistent with EPRI MRP interim guidance, which has not been approved by the NRC, but is more conservative than the guidance in the NRC-approved MRP-227-A. Reexamination of original BFBs during each refueling outage as proposed by the applicant is also more conservative than the 6-year maximum interval for subsequent examination for downflow plants finding more than 3 percent degraded BFBs during the initial examination, specified in the EPRI MRP interim guidance (which is also more conservative than the 10-year interval for subsequent examination allowed by MRP-227-A).

In item 2, the applicant stated that it would perform UT of 100 percent of original BFBs during each refueling outage, if any of the original BFBs are needed to ensure structural integrity of the baffle assembly, at both IP2 and IP3. Therefore, if the applicant replaces additional bolts such that structural integrity can be ensured based only on the replacement bolts, no UT examination of original bolts will be necessary.

For replacement bolts, based on items 3 and 4, UT examination will not be performed during future refueling outages unless a general visual examination of the baffle structure reveals anomalies. The staff was concerned because the applicant did not provide sufficient detail about these general visual examinations for the staff to determine whether the visual examinations would be capable of detecting degraded replacement bolts. The applicant also did not specify any timing for the UT examination of replacement bolts if the visual examination reveals degraded bolts. Therefore, in RAI 1 (ADAMS Accession No. ML17151A312), the staff requested the following information:

(a) Describe the examination coverage and method (e.g., VT-1, VT-3) of the general visual inspection of the baffle structure discussed in item 3.

(b) Clarify what is meant by "anomalies." What conditions observed during the visual examination would trigger a UT examination of replacement BFBs?

(c) Justify that the general visual inspection will be capable of detecting any and all visually degraded replacement bolts.

(d) If the general visual examination reveals degraded replacement BFBs, when will the UT examination of the replacement bolts be performed? Justify the timing of this examination, if not performed during the same refueling outage as the discovery of the degraded replacement BFBs.

In its May 24, 2017 response to RAI 1 item a (ADAMS Accession No. ML17151A312), the applicant stated that it will perform a VT-3 of the baffle assembly, including the baffle plates, the edge bolts, and the replacement BFBs during each subsequent refueling outage. The applicant also revised the RVI Inspection Plan, Section 6.2 item 3, to include this additional detail.

The staff finds the applicant's response to RAI 1, item a, to be acceptable because the applicant clarified the visual examination method and coverage.

In response to RAI 1, item b, the applicant stated that the VT-3 examination will be capable of detecting baffle bolt anomalies similar to those previously detected at other Westinghouse four-loop downflow plants (i.e., Tier 1a plants as defined in Westinghouse NSLA 16-1). The response further stated that examples of baffle bolt anomalies include missing or protruding bolt heads, missing or protruding lock bars, cracked lock bar welds, or other signs of bolt damage or unthreading, and that for the replacement BFBs, the anomalies include deformed, protruding, or cracked locking cups; damaged, protruding, or cracked bolt heads, or other signs of bolt unthreading. The response also stated that identifications of these anomalies on the replacement baffle bolts would trigger a UT examination of the replacement bolts during the same refueling outage. The applicant also provided a revision of Section 6.2, item 3, to add this additional detail on the anomalies that will be looked for in the VT-3 examination of the baffle structure.

The staff finds the applicant's response to RAI 1, item b, acceptable because the conditions described by the applicant are those conditions that operating experience has shown are typically associated with BFB degradation, when the BFB degradation has progressed to the point that some BFBs have completely failed. RAI 1, item b, is therefore resolved.

In its response to RAI 1, item c, the applicant indicated that the general visual inspection is intended to identify the anomalies described in its response to RAI 1, item b, and cannot detect cracking located below the replacement bolt head, but that UT examinations performed every 10 years will be capable of detecting bolt cracking below the head. The applicant then provided a discussion justifying that an interval of 10 years for subsequent UT examinations of replacement BFBs is appropriate and conservative.

The applicant provided sufficient detail in the response to RAI 1, item c, to demonstrate that any visually detectable signs of failure of the replacement bolts will be detected by the VT-3 examination. RAI 1, item c is therefore resolved.

In response to RAI 1, item d, the applicant stated that it will perform volumetric examinations of the replacement bolts during the same refueling outage in which the general visual inspection identifies degraded replacement bolts.

The staff finds the response to RAI 1, item d, acceptable because UT examination in the same refueling outage that degraded replacement bolts were identified by the visual examination would allow the complete extent of degradation in the replacement bolts to be characterized, such that appropriate corrective actions could be determined. RAI 1, item d, is therefore resolved.

The staff finds the performance of a VT-3 visual examination of the baffle assembly during each refueling outage to be an acceptable method to manage the potential for aging of the replacement BFBs, because the examination will include the replacement bolts, and it will look for the types of conditions associated with BFB degradation. The staff finds that UT examination of the replacement BFBs is not necessary unless the VT-3 examination finds evidence of degradation in these bolts, because replacement bolts use a material and design that makes them less susceptible to irradiation-assisted stress-corrosion cracking (IASCC), and will have much less time inservice and thus much less neutron fluence than original bolts. Replacement BFB degradation has only occurred when large numbers of undetected degraded original BFBs were present in close proximity to the replacement BFB. Therefore, the likelihood of degradation in replacement bolts is lower than for original bolts, and UT examination is generally not warranted for these bolts.

In item 5, the applicant stated that it will replace all bolts with indications that are needed to remain structurally capable of carrying their design load to ensure structural integrity of the baffle structure during all design conditions, and that it will replace additional "good" or anti-cluster bolts to ensure that sufficient margin is maintained to accommodate the same failure rate until the next inspection as the failure rate identified during the current refueling outage. The applicant further stated that this margin will ensure compliance with the intent of the guidelines provided in WCAP-17096, Revision 2, "Reactor Internals Acceptance Criteria Methodology and Data Requirements." The goal of the WCAP-17096-NP-A methodology is to demonstrate that the projected number of additional bolt failures will not threaten the acceptable pattern before the next scheduled inspection. Although the failure rates of BFBs cannot currently be precisely predicted, it is likely that the degradation found during the initial examinations of IP2 and IP3 developed over many cycles. Additionally, installation of additional replacement bolts reduces stresses on remaining original bolts, which should reduce the susceptibility of these bolts to failure. In addition, "Indian Point Nuclear Generating - Integrated Inspection Report 05000247/2016002 and 05000286/2016002, April 1, 2016, through June 30, 2016," dated August 30, 2016 (ADAMS Accession No. ML16243A245) indicates that the replacement BFBs for IP2 are Type 316 stainless steel, with a more gradual fillet geometry between the bolt head and shank, which is intended to reduce the stress concentration at that transition. Therefore, the replacement BFBs should have improved resistance to IASCC and fatigue compared to the original BFBs. Given that all identified degraded bolts will be replaced before startup, and additional original bolts will be replaced with bolts with improved cracking resistance to provide more structural margin, the staff finds that a one-cycle interval for subsequent examination is sufficient. Therefore, a subsequent examination interval of one cycle (2 years) is acceptable.

Operating experience from Cook, Unit 2, suggests that replacement bolts and baffle-edge bolts may be susceptible to degradation if a large number of clustered original degraded bolts are present near the replacement bolts. Therefore, in RAI 2, the staff asked:

If clustering of degraded original BFBs is found at IP2 or IP3, during future refueling outages:

(a) Will UT examination be performed on replacement BFBs installed during previous outages? If so, describe the scope and schedule of these examinations.

(b) Will baffle-edge bolts be examined? If so, describe the method, scope, and schedule of these examinations.

(c) If the UT examination of replacement BFBs and examination of edge bolts will not be performed if clustered degraded original bolts are found, justify not performing these examinations.

In its May 24, 2017 response to RAI 2, item a, the applicant stated that because IP2 and IP3 have performed a 100 percent UT examination of all original bolts and have replaced all degraded bolts plus additional reinforcing bolts, it does not believe the operating experience from Cook, Unit 2, directly applies to IP2 and IP3. However, the applicant stated that if clusters of failed original bolts are observed during future examinations, Entergy procedures require entering the condition into the Indian Point corrective action program, and that an evaluation (under the corrective action program) would determine if UT examination of the adjacent replacement bolts is warranted. The applicant further stated that if this evaluation indicates that the clusters could have resulted in damage to the replacement bolts (i.e., an overstress condition), then a UT examination of the replacement bolts will be performed during the same refueling outage. Finally, the applicant stated that if the MRP under NEI 03-08 issues new guidance addressing the impact of clusters of failed original bolts on replacement bolts, Entergy will apply that new MRP guidance.

In response to RAI 2, item b, the applicant indicated that edge bolts would be examined during each refueling outage as part of the general visual inspection of the baffle assembly described in the response to RAI 1, item a, and that any degraded edge bolts would be evaluated through the Indian Point Corrective Action Program. The applicant further stated that a volumetric examination is not necessary because the edge bolts are not credited in the structural analyses of the baffle assembly, but that it would apply any future MRP guidance under NEI 03-08 related to edge bolts.

In response to RAI 2, item c, the applicant reiterated its response to RAI 2, item a, for the BFBs. For the edge bolts, the applicant stated that volumetric examination of edge bolts is unnecessary as stated in the response to RAI 2, item b.

The staff finds the applicant's response to RAI 2 acceptable because it clarified how it would determine if UT examination of replacement bolts is necessary if clusters of degraded original bolts were found. Use of the corrective action program is appropriate since there could be many different scenarios that could occur related to clustered degradation of original bolts. In addition, since the edge bolts will be visually examined during each refueling outage, any failed edge bolts should be detected, whether or not these failures are related to clustered failures of original bolts. RAI 2 is therefore resolved.

The staff finds the applicant's proposed modifications to its RVI Inspection Plan to address operating experience with BFB degradation to be acceptable because:

- The applicant has completed initial (baseline) examinations of BFBs at IP2 and IP3 in accordance with MRP-227-A, as modified by EPRI MRP interim guidance, and has replaced all degraded bolts, plus additional non-degraded bolts to provide additional structural margin.
- Performing subsequent examination of remaining original BFBs during each refueling provides reasonable assurance that any additional degradation of original bolts will be detected in a timely manner, and is conservative compared to industry interim guidance.
- The applicant plans to either replace original BFBs susceptible to IASCC or continue to examine the original BFBs each refueling outage, if needed for structural integrity.
- Although replacement BFBs and baffle-edge bolts are less likely to experience degradation, the applicant will perform VT-3 visual examination of these bolts during each refueling outage, which will provide an indication if there are problems with these bolts.

Conclusion. On the basis of its review of the changes to the examinations for BFBs, the staff concludes that the applicant has demonstrated that the effects of aging on the BFBs will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff concludes that the proposed RVI Inspection Plan implements the elements of the RVI AMP in an acceptable manner. The bases for the staff's conclusion are that (1) the applicant's program is consistent with the generic RVI inspection and evaluation guidelines of MRP-227-A, with the exception of BFBs, for which the AMP has been appropriately modified in response to industry and plant-specific operating experience, consistent with EPRI interim guidance; (2) the applicant adequately addressed all of the A/LAIs of the final SE for MRP-227, Revision 0, that are applicable to Westinghouse-designed RVIs or generically to all NSSS designs; and (3) the RVI Inspection Plan addresses the conditions of the final SE for MRP-227, Revision 0.

3.0.3.3.11 Coating Integrity Program

Summary of Technical Information in the Application. As supplemented by letter dated March 10, 2015 (ADAMS Accession No. ML15075A022), LRA Section B.1.43 describes the new Coating Integrity Program as consistent, with exceptions, with GALL Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks." The supplement states that the AMP is a new program that will include periodic visual inspections of internal coatings/linings. It also states that if visual inspection of the coated/lined surfaces determines that any coating/lining is deficient or degraded, physical tests will be performed, if possible, in conjunction with the visual inspection. It further states that it will follow guidance provided in EPRI Report 1019157, "Guideline on Safety-Related Coatings." It states that the program will be implemented before December 31, 2024.

Staff Evaluation. The staff issued LR-ISG-2013-01, "Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," on November 14, 2014. In a letter dated December 2, 2014 (ADAMS Accession No. ML14325A198), the staff issued RAI 3.0.3-2. In the request, the staff sought information regarding how the applicant plans to manage the effects of aging on internal coatings in accordance with the license renewal interim staff guidance LR-ISG-2013-01. By letter dated March 10, 2015, the applicant: (a) provided the new Coating Integrity Program; (b) identified applicable AERM for certain internally coated in-scope components; and (c) proposed revisions to its LRA to address LR-ISG-2013-01.

The staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.M42. For the "detection of aging effects" program element, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

The "detection of aging effects" program element in GALL Report AMP XI.M42 recommends that aging effects associated with coatings exposed to treated borated water be managed. Coating environments greater than 140 °F are not evaluated in the GALL Report program. The applicant's program, as provided in its letter dated March 10, 2015, LRA Table 3.3.2-19-43-IP3, "Pressurizer System," states that loss of coating integrity is managed for metal components with internal coating in a treated borated water greater than 140°F environment. The staff lacks sufficient information to conclude that the guidance in AMP XI.M42 is adequate for the materials exposed to temperatures greater than 140°F. By letter dated July 7, 2015 (ADAMS Accession No. ML15170A456), the staff issued RAI 3.0.3-16 requesting that the applicant explain how aging effects associated with coating materials exposed to temperatures greater than 140°F are managed.

In its response dated September 1, 2015 (ADAMS Accession No. ML15251A237), the applicant stated that it had performed a further review of the subject material/environment combination and had determined that the assumption of temperature greater than 140°F was overly conservative. It also stated that the nominal (normal operating temperature during plant operation) internal temperature for the pressurizer relief tank is less than 140°F. As a result, the applicant updated the materials/environment combination in the LRA section in its response. The staff finds the applicant's response acceptable because the revised material/environment combination is consistent with what GALL Report AMP XI.M42 has evaluated for the corrected environment. The staff's concern described in RAI 3.0.3-16 is resolved.

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

*Exception 1*. As supplemented by letter dated March 10, 2015, LRA Section B.1.43 includes an exception to the "detection of aging effects" program element. In this exception the applicant stated that for the city water systems, it will perform volumetric inspection on concrete-lined piping in lieu of visual inspection of internal coating, as recommended by the GALL Report. The applicant stated that the volumetric inspection is capable of detecting pipe wall thinning resulting from losses of the internal concrete coating, and also degradation at welded joints where a gap in the concrete lining might exist, based on plant operating experience in managing the effects of aging in concrete-lined service water system piping. It further stated that the system flushing and flow testing will ensure that the concrete lining has not caused flow blockage downstream.

The staff reviewed this exception against the corresponding program element in GALL Report AMP XI.M42 and finds it acceptable because: (a) the proposed volumetric inspection technique, based on its plant-specific operating experience, provides an acceptable level of quality and safety as compared to using the visual inspection technique recommended in the GALL Report guidance in accordance with Table 4a, "Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers," of AMP XI.M42; and (b) the aging effect of wall thinning due to loss of internal coating would be detected as effectively as if internal visual inspections were being conducted on this part of city water piping.

Exception 2. As supplemented by letter dated March 10, 2015, LRA Section B.1.43 includes an exception to the “detection of aging effects” program element. In this exception, the applicant stated that for the fire water systems, it will perform volumetric inspection on concrete-lined piping in lieu of visual inspection of internal coating, as recommended by the GALL Report. The applicant stated that the volumetric inspection is capable of detecting pipe wall thinning resulting from losses of the internal concrete coating, and also degradation at welded joints where a gap in the concrete lining may exist. It further stated that the inspection technique has been demonstrated to be effective in detecting the effects of aging on concrete-lined service water system piping.

The staff reviewed this exception against the corresponding program element in GALL Report AMP XI.M42 and finds it acceptable because: (a) the proposed volumetric inspection technique, based on its plant-specific operating experience, provides an acceptable level of quality and safety as compared to using the visual inspection technique recommended in the GALL Report in accordance with Table 4a of AMP XI.M42; (b) a similar technique was used effectively in managing the aging effect of wall thinning due to loss of internal coating in its service water piping; (c) the aging effect of wall thinning due to loss of internal coating would be detected as effectively as if internal visual inspections were being conducted on this part of fire water piping; and (d) system flushing and flow testing will ensure that the concrete lining will not cause flow blockage downstream.

Based on its review of the applicant’s Coating Integrity Program and response to RAI 3.0.3-16, the staff finds that program elements one through seven for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M42. The staff also reviewed the exceptions associated with the “detection of aging effects” program element, and their justifications, and finds that the AMP, with the exceptions, is adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.1.43 summarizes operating experience related to the Coatings Integrity Program. The applicant stated that the Coatings Integrity Program is a new program. It stated that industry operating experience will be considered in the implementation of this program. It also stated that it has gained plant-specific operating experience during inspections and in managing aging effects associated with the internally-lined service water systems. Additional plant operating experience will be gained as the program is implemented and will be factored into, and addressed by, the corrective action program.

The staff reviewed operating experience information in the application to determine whether the applicable aging effects and industry and plant-specific operating experience were reviewed by the applicant. The staff did not identify any operating experience that would indicate that the applicant should consider modifying its proposed program.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. In addition, the staff finds that the conditions and operating experience at the plant are bounded by those for which GALL Report AMP XI.M42 was evaluated.

UFSAR Supplement. As supplemented through letter dated March 10, 2015, LRA Section A.1.43 provides the UFSAR supplement for the Coating Integrity Program. The staff reviewed this UFSAR supplement description of the program against the recommended description for this type of program as described in SRP-LR Table 3.0-1, as modified by LR-ISG-2013-01, and noted that the applicant stated that baseline coating/lining inspections will be completed and the program implemented by December 31, 2024. By letter dated July 7, 2015, the staff issued RAI 3.0.3-17 requesting that the applicant explain how loss of coating integrity will be managed between 2015 and the proposed implementation dates (from 2015 to 2024). The staff noted that in the applicant's response to RAI 3.0.3 17, dated September 1, 2015, the baseline inspections to be conducted from 2015 to 2024 include all accessible surfaces of internally coated tanks and heat exchangers, and all of the sampling-based inspections for piping recommended by GALL Report AMP XI.M42. The applicant stated that, "the condition of inspected coatings at the site will be reviewed, and if deficiencies or degradations are identified, the program requirements for followup actions will be performed." The staff finds the applicant's response acceptable because: (a) the extent of inspections and (b) the acceptance criteria and corrective actions associated with the inspections will be consistent with those recommended in GALL Report AMP XI.M42. The staff's concern described in RAI 3.0.3-17 is resolved. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its review of the applicant's Coating Integrity Program, the staff finds 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 finds that the AMP, with the exceptions, is adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.4 Changes to the LRA To Address LR-ISG-2012-02

The staff issued LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," on November 22, 2013, in the *Federal Register* (FR) (78 FR 226), to address aging effects associated with recurring internal corrosion, fire water systems, atmospheric storage tanks, CUI, and other changes to the GALL Report and SRP-LR. By letter dated April 1, 2014, the staff issued RAI 3.0.3-1 requesting that the applicant state how the updated guidance in LR-ISG-2012-02 has been accounted for in its AMPs and AMR items. By letter dated December 16, 2014 (ADAMS Accession No. ML14365A069), the applicant responded to this RAI.

The staff's evaluation of the below referenced programs before the issuance of the applicant's responses to RAI 3.0.3-1 is documented in NUREG-1930, "Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3." The staff's evaluation of the applicant's RAI responses follows.

3.0.3.4.1 Recurring Internal Corrosion in the Fire Protection-Water and City Water Systems

Summary of Technical Information. By letter dated April 1, 2014 (ADAMS Accession No. ML14084A387), the staff issued RAI 3.0.3-1 requesting that the applicant provide details on how the updated guidance of LR-ISG-2012-02, has been accounted for in AMPs and AMR items; or where the revised recommendations will not be incorporated, state an exception and the basis for the exception. In its response dated December 16, 2014, the applicant stated that recurring internal corrosion (RIC) because of loss of material due to general, pitting, and crevice corrosion leading to through-wall leaks has occurred in the fire protection-water, and city water systems.

Staff Evaluation. Based on its review of the applicant's response, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

Fire Protection -Water. The applicant stated that the Fire Water System Program includes volumetric wall thickness measurements used to ensure that wall thickness is within the required structural limits. The applicant also stated that the wall thickness measurements conducted for IP2 before the end of its original operating term did not identify any unacceptable wall thinning. The applicant also stated that, "[l]ocalized corrosion has resulted in minor through-wall leaks that have no impact on system performance and do not threaten the structural integrity of the piping or the safety function of nearby equipment." The applicant did not propose any changes to its Fire Water System Program to address RIC.

City Water. The applicant stated that loss of material in the city water system is managed by the Periodic Surveillance and Preventive Maintenance Program. The applicant also stated that, "[h]owever, based on past operating experience, they [through-wall leaks] do not compromise the intended functions of these or any other system, and do not warrant AMP activities beyond those provided by established AMPs and the corrective action program." In a letter dated September 26, 2012 (ADAMS Accession No. ML12285A084), the applicant stated that visual inspection or other NDE techniques will be used to inspect a representative sample of the internals of city water piping, and piping components to manage loss of material. The applicant did not propose any changes to its Periodic Surveillance and Preventive Maintenance Program to address RIC.

Buried Piping Susceptible to RIC. The staff's evaluation of the applicant's response to RIC in the service water system is documented in SER Section 3.0.3.1.14,

The applicant stated that the service water fire protection-water and city water systems include buried piping. The applicant also stated:

> Although leaks in buried piping are possible, underground leaks large enough to affect the function of these systems are not expected based on operating experience with the aboveground portions of these systems. If large leaks were to occur, they would be expected to develop slowly and would be detectable by changes in system performance (e.g., changes in instrumentation readings or reduced cooling capacity), changes in system operation (e.g., more frequent pressure maintenance / jockey pump operation), or by the appearance near the leak of wetted ground, sink holes, or other ground anomalies.

The staff lacked sufficient information to conclude that the Fire Water System Program and Periodic Surveillance and Preventive Maintenance Program will manage RIC such that there is reasonable assurance that the fire protection-water system and the city water system and in-scope systems in the vicinity of these systems will be capable of performing their intended functions during the period of extended operation. By letter dated May 4, 2015 (ADAMS Accession No. ML15071A101), the staff issued RAI 3.0.3-5, requesting that the applicant state the basis and justification for concluding that: (a) existing inspection data are sufficient to demonstrate that general corrosion is progressing slowly enough that it will not prevent an in-scope component from performing its CLB intended function during the period of extended operation; and (b) state the basis and justification for concluding that through-wall leaks will not impact the safety function of nearby equipment throughout the period of extended operation.

In its response dated August 18, 2015 (ADAMS Accession No. ML15236A017), the applicant stated that the fire water and city water systems are exposed to treated water supplied by the Town of Buchanan municipal water supply. The applicant also stated:

> This potable water is tested periodically by the Town to ensure its quality. It is non-corrosive. Therefore, internal corrosion rates in these systems have historically been low and are expected to remain low. As discussed below, recent inspection data confirm that corrosion rates are low and unlikely to prevent an in-scope component from performing its CLB intended function during the period of extended operation (PEO).

The applicant further stated that it conducted 14 ultrasonic wall thickness measurements (9 on IP1 and 5 on IP2) on aboveground fire-protection water system piping in 2013. The applicant concluded the following based on these results: (a) all locations will exceed the allowable minimum thickness throughout the period of extended operation; (b) internal corrosion rates are not expected to cause the piping to exceed structural integrity requirements; (c) given that buried and aboveground piping have the same internal environment, the aboveground results bound the buried piping projected conditions; (d) the inspection results are representative of IP2 and IP3 piping because the piping was installed with similar piping specifications; and (e) "current inspection data are sufficient to demonstrate that general corrosion is progressing slowly enough that it will not prevent an in-scope component from performing its CLB intended function during the PEO." The applicant stated that, "[a]lthough some pinhole leaks in piping have occurred due to localized pitting corrosion, that corrosion mechanism is localized (not severe) and would rarely, if ever, affect the structural integrity of the piping. Further, NDE exams typically are performed to confirm that degradation associated with through-wall leaks is localized, and to confirm the integrity of the piping."

The staff deferred its evaluation of the applicant's response to RAI 3.0.3-5 to after an onsite audit conducted in February 2016 (ADAMS Accession No. ML17250A244). During the audit, the staff noted that two events listed below had occurred at the station that impacted the performance of the fire protection-water system.

> IP2 – NRC Integrated Inspection Report 050000247/2003011 (ADAMS Accession No. ML033140584) documents a September 10, 2003, 80-gallon per minute leak that resulted in the fire water header not being available to perform its intended function for approximately 3 hours. The apparent cause for this leak states, "[t]he apparent cause for the pin-hole leak is age related corrosion degradation of the piping, specifically, high-oxygenation pitting corrosion. The piping is original Unit 1 equipment, schedule 40 un-lined black steel pipe that is approximately 45 years old. The follow-up UT inspections indicated that the corrosion mechanism that resulted in the pinhole was not general pipe corrosion but was localized in the pinhole. The periodic testing of the system introduces fresh oxygen to the system and such cyclic re-oxygenation results in pits caused by 'high-oxygenation corrosion.' These pits then grow to become through-wall pinhole leaks in the piping. Portions not subject to periodic flow are not subject to this corrosion mechanism."

> IP2 – NRC Integrated Inspection Report 05000247/2015001 and 05000286/2015001 (ADAMS Accession No. ML15133A264) documents a December 29, 2014, failure of a 10-inch piping spool piece in the IP1 high pressure fire protection header that resulted in the fire water header to IP2 not

> being available to perform its intended function for about 2 hours. The failure was as a result of a crack opening up along the longitudinal seam weld along the bottom of the pipe. Three previously identified pinhole leaks were located along the length of the cracked region.

The staff reviewed plant-specific documents during the audit. During the time frame from 2007 through 2015, there were approximately 42 leaks in the fire-protection water system and 14 in the city water system. Sixteen of the fire water leaks were inspected using ultrasonic thickness techniques. Ultrasonic inspections were conducted on an additional 14 locations at IP2. Based on the applicant's evaluation of all of the thickness measurements, structural integrity requirements were met. The staff reviewed the applicant's analytical techniques. The applicant has generated a preventive maintenance activity to perform ultrasonic inspections at the additional 14 locations by 2023. The staff reviewed the ultrasonic thickness reports for two of the leaks associated with the December 29, 2014, failure. The staff projected potential loss of material based on corrosion rates documented in the applicant's calculations. It appeared that structural integrity requirements would have been met on the day of the failure. Based on its review of documents during the audit, the staff concluded that solely conducting ultrasonic wall thickness examinations accompanied by using structural integrity requirements as the acceptance criterion might not result in prevention of potential future losses of intended function of the fire water and city water system. By letter dated July 25, 2016 (ADAMS Accession No. ML16138A194), the staff issued RAI 3.0.3-9 requesting that the applicant: (a) state the cause of the failure on December 29, 2014. If possible, provide additional information related to the cause of the failure on September 10, 2003; and (b) propose changes to AMPs, as applicable, to address recurring internal corrosion in the fire water and city water systems or provide the basis as to why changes are not necessary.

In its response dated December 2, 2016 (ADAMS Accession No. ML16350A005), the applicant stated:

> Based upon photographic evidence and contemporaneous field observations of the failed fire protection pipe section, the December 29, 2014, piping leak appears to have been caused by selective seam corrosion attack on the longitudinal seam weld. That seam weld was located along the bottom (6 o'clock position) of the pipe, the same portion of the pipe from which the leakage was observed. Entergy personnel had observed previous leakage along the longitudinal seam weld on the bottom of the piping segment. The selective seam corrosion in the crevice formed by the seam may have been exacerbated by microbiologically influenced corrosion (MIC) or under-deposit corrosion.
>
> The leak associated with the September 10, 2003 event began as a pinhole and grew to a nominal 3/8" hole, discharging approximately 80-90 gallons per minute (gpm). The rate of discharge and potential for runoff to adjacent safety-related equipment areas mandated that the fire water supply system be secured until a temporary clamp could be installed. For that reason, there was a temporary loss of intended function of the fire water header. However, during the clamp installation, the system could have been manually returned to service if necessary to combat fire.

The applicant also stated that if loss of material due to corrosion meets the criteria for RIC (defined in LR-ISG-2012-02), wall thickness inspections will be conducted in 25 locations every 5 years during the period of extended operation until RIC has subsided. The inspections will occur “at selected locations to provide a representative sample of the type of piping and environment where recurring internal corrosion is identified.” Plant-specific procedures will allow for the inspection locations to change based on the relevance and usefulness of the measurements. Additional inspections will be performed as follows:

- If greater than 1 and less than 5 degraded locations are found in the 5-year interval, then as a minimum, 10 additional volumetric examinations of system welds will be performed during the following refueling interval.
- If greater than 5 degraded locations are found, then a minimum of 15 additional volumetric examinations will be performed during the following refueling interval.

The Fire Water System Program will be revised to require that when, “individual piping segments are found with multiple leaks or degraded areas that align to indicate selective seam corrosion, then corrective action will be taken to replace the affected piping segment.”

For the city water system, the Periodic Surveillance and Preventive Maintenance Program will be revised to include periodic internal visual or wall thickness measurements of a representative sample of 25 components every 5 years. Additional inspections will be performed as described above if “the frequency of internal corrosion meets the criteria for recurring internal corrosion.”

The applicant further stated that for piping that is found to be degraded and returned to service, the remaining service life will be calculated and the piping will be re-examined prior to the end of the calculated life.

The applicant revised LRA Sections A.2.1.13, A.2.1.28, A.3.1.13, and A.3.1.28 to incorporate the number and periodicity of inspections, number of additional inspections that will be conducted if degraded conditions are found, service life calculations if degraded pipe is returned to service, the allowance to change inspection locations based on measurements, and the provision to replace piping segments when multiple leaks or degraded areas align with pipe seams. The Fire Water System Program will be enhanced to incorporate the changes described in the UFSAR supplement. The Periodic Surveillance and Preventive Maintenance Program was enhanced to incorporate the number and periodicity of inspections, the number of additional inspections that will be conducted if degraded conditions are found; and service life calculations if degraded pipe is returned to service. Commitment No. 8 was revised to address the changes to the Fire Water System Program. Commitment No. 21 was revised to address the changes to the Periodic Surveillance and Preventive Maintenance Program.

The staff noted that conducting 25 wall thickness measurements every 5 years appropriately exceeds the number of inspections recommended in other sampling-based programs (e.g., GALL Report AMP XI.M38). The staff also noted that the number of additional inspections to be conducted when degraded conditions are detected appropriately exceeds the number of increased inspections as recommended by the staff in Generic Letter 90-05, “Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3 Piping.” The staff found the changes described in the response to RAI 3.0.3-9 acceptable in part because the number and periodicity of inspections and the number of additional inspections that will be conducted if degraded conditions are found should be sufficient to detect RIC. However, the staff found the response to RAIs 3.0.3-5 and 3.0.3-9 inadequate as described below. By letter dated March 8, 2017 (ADAMS Accession No. ML17046A231), the staff issued followup RAIs to address each of the below issues.

- As demonstrated with the two events where leakage resulted in the fire water header being removed from service, use of a service life calculation based on structural integrity might not be adequate by itself to provide reasonable assurance that future leaks will not result in a loss of intended function. As a result, it is not clear that the acceptance criteria and corrective actions would be adequate.

  In its response dated May 8, 2017 (ADAMS Accession No. ML17132A175), the applicant provided a summary of its structural integrity evaluations of the September 10, 2013, and December 29, 2014, leaks, including a pinhole detected in 2008. The applicant stated that with the exception of the area surrounding the flaw, the measured wall thickness was greater than 87.5 percent of the nominal wall pipe thickness. The applicant also stated that demonstrating adequate structural integrity, "provide[s] adequate assurance that a large-scale leak would not occur." The applicant: (a) revised LRA Sections A.2.1.13 (Fire Water System Program for Unit 2), A.2.1.28 (Periodic Surveillance and Preventive Maintenance Program for Unit 2), A.3.1.13 (Fire Water System Program for Unit 3), and A.3.1.28 (Periodic Surveillance and Preventive Maintenance Program for Unit 3); (b) enhanced the "corrective actions" program element of the Fire Water System Program and Periodic Surveillance and Preventive Maintenance Program; and (c) revised Commitment Nos. 8 (Fire Water System Program) and 21 (Periodic Surveillance and Preventive Maintenance Program) as follows:

  – 'piping that exhibits leaks will be locally repaired and restored to service on an interim basis presuming ultrasonic test data reflects adequate structural integrity to support interim operation. The affected piping segment will be entered into the 12-week work control schedule for replacement.'

  – 'piping segments that exhibit indications of selective seam corrosion will be entered into the routine 12-week work control schedule and processed on an accelerated replacement basis.'

  The staff noted that the use of 87.5 percent of nominal wall as a criterion for acceptance of structural integrity is not necessarily adequate in and of itself. However, based on the applicant's analyses that the staff reviewed during the February 2016 audit, the staff agrees that structural integrity would have been met when the leaks occurred. The staff also noted that based on its review of the applicant's analyses and pictures of the leakage that occurred during the December 29, 2014, leakage event; although structural integrity was met in the immediate vicinity of the pinhole leak, multiple pits in the seam resulted in a larger leak.

  The staff finds the applicant's response and changes to the program and associated UFSAR supplements acceptable because: (a) when leaks are detected, the local area will be assessed for structural integrity; and (b) corrective actions have been enhanced to include local repairs capable of stopping the leak and mitigating potential leak rate increases before replacement of the degraded piping segment.

- The term "until RIC has subsided" as used in association with conducting wall thickness measurements is undefined. LR-ISG-2012-02, Section 3.3.2.2.8, "Loss of material due to Recurring Internal Corrosion," defines RIC as, "if the search of plant-specific OE reveals repetitive occurrences (e.g., one per refueling outage cycle that has occurred over: (a) three or more sequential or nonsequential cycles for a 10-year OE search, or (b) two or more sequential or nonsequential cycles for a 5-year OE search) of aging effects with the same aging mechanism in which the aging effect resulted in the component either not meeting plant-specific acceptance criteria or experiencing a reduction in wall thickness greater than 50 percent (regardless of the minimum wall thickness)". It is not clear how "subsided" would be integrated with the criteria in LR-ISG-2012-02.

In its response dated May 8, 2017, the applicant stated:

> The phrase "until RIC has subsided" was intended to mean until the frequency of occurrence of piping leaks and significant wall thinning no longer meets the criteria for characterization as "recurring internal corrosion" as defined in LR-ISG-2012-02; NUREG-1801, Section IX.F. The frequency will be assessed on a rolling five-year period. The use of the term "subsided" reflects a reduction in occurrences to a frequency below the threshold for classification as RIC.

The staff finds the applicant's response acceptable because its use of the term "until RIC has subsided" is consistent with the LR-ISG-2012-02 RIC criteria.

- The Fire Water System Program is being modified to state, "individual piping segments are found with multiple leaks or degraded areas that align to indicate selective seam corrosion, then corrective action will be taken to replace the affected piping segment." However, the changes to the program and UFSAR supplement do not specify the timing of the replacement. No basis was provided for why piping segments with multiple leaks or degraded areas are acceptable to be returned to service without potentially affecting the intended function of the system.

  In its response dated May 8, 2017, the applicant stated that leaks will be evaluated and repaired. The applicant also stated that, "[i]f routine inspections identify evidence of selective seam corrosion, IPEC will replace the affected piping segment on an accelerated schedule within the 12-week work schedule." The applicant further stated that, "[a]ny discovered leaks that are not indicative of a pattern suggesting selective seam corrosion will be cause for entry of the affected piping segment(s) into the 12-week work schedule, for timely replacement." The applicant stated that "unforeseen circumstances" could necessitate additional time to implement a replacement. However, as stated above, the applicant has revised its programs to state, "piping that exhibits leaks will be locally repaired and restored to service on an interim basis presuming ultrasonic test data reflects adequate structural integrity to support interim operation."

  The staff noted that it is the applicant's intent that leak locations with the potential to result in higher leak rates (i.e., selective seam corrosion) will be replaced on an accelerated basis. The staff recognizes that unforeseen circumstances could extend replacement activities. The staff also noted that installation of local repairs (e.g., pipe clamp) can result in stopping the leak and mitigating potential leak rate increases before replacement of the degraded piping segment. The staff finds the applicant's response and changes to the programs and associated UFSAR supplements acceptable because: (a) depending on the configuration of the piping in the leak area, pipe replacement will typically occur on an accelerated basis or within the 12-week work control schedule; and (b) local repairs will be conducted that are capable of stopping the leak and mitigating potential leak rate increases prior to replacement of the degraded piping segment.

- It is not clear to the staff how internal visual inspections conducted for the Periodic Surveillance and Preventive Maintenance Program will be capable of quantifying wall loss.

In its response dated May 8, 2017, the applicant stated that visual inspections provide a qualitative basis to determine the need for subsequent wall thickness measurements. The applicant also stated that visual inspections provide an effective means of identifying selective seam corrosion.

The staff noted that during its review of plant documents during the February 2016 audit, no instances were found where, even with leaks, a loss of intended function of the city water system occurred. Based on plant-specific operating experience, selective seam corrosion in the fire-protection water system has resulted in more severe pipe leakage rates. The staff finds the applicant's response and revisions to the city water system acceptable because: (a) insights provided by the required wall thickness measurements of the fire-protection water system are equally applicable to the city water system; (b) internal visual inspections are capable of detecting the extent of pitting in seams and as a result identifying the potentially most impactful leaks; and (c) the internal visual inspections will be evaluated against the criteria for recurring internal corrosion, which implies that internal corrosion will have to be quantified.

On the basis of its audit and review of changes to the applicant's Fire Water System Program and Periodic Surveillance and Preventive Maintenance Program, the staff concludes that the applicant has demonstrated that the effects of recurring internal corrosion will be adequately managed for the fire-protection water system and city water system so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplements for these AMPs and concludes that they provide an adequate summary description of the programs, as required by 10 CFR 54.21(d).

3.0.3.4.2 Representative Minimum Sample Size for Periodic Inspections in GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"

In its response dated December 16, 2014 (ADAMS Accession No. ML14365A069), associated with the representative minimum sample size for periodic inspections in GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," the applicant stated that its External Surfaces Monitoring Program or Periodic Surveillance and Preventive Maintenance Program manages the effects of aging on the internal surfaces of piping and ducting. The applicant also stated that no additional changes were made to the LRA associated with Section B, "Representative minimum sample size for periodic inspections in GALL Report AMP XI.M38, 'Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,' of LR-ISG-2012-02 because the AMPs being credited for managing the applicable aging effects already account for inspecting a representative sample size.

The staff reviewed the applicant's claim that the two programs being credited for managing the effects of aging on the internal surfaces of piping and ducting are consistent with the guidance in Section B of LR-ISG-2012-02. The External Surfaces Monitoring Program is used to manage the loss of material of internal surfaces when the internal and external surfaces are exposed to the same environments and constructed from the same material. The External Surfaces Monitoring Program is a condition monitoring program based on system inspections and walkdowns. The nature of this program ensures that a representative minimum sample size will be inspected. The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in NUREG-1930, Section 3.0.3.2.5. The Periodic Surveillance and Preventive Maintenance Program is a plant-specific program that manages aging effects that are not managed by other AMPs. The Periodic Surveillance and Preventive Maintenance Program contains inspection frequencies and requirements for representative minimum sample size, which are consistent with the guidance in Section B of LR-ISG-2012-02. The staff's evaluation of the applicant's Periodic Surveillance and Preventive Maintenance Program is documented in NUREG-1930, Section 3.0.3.3.7.

Based on its review of the applicant's response to RAI 3.0.3 1 and the LRA, the staff finds that the programs are consistent with the guidance in Section B of LR-ISG-2012-02 and adequate to manage the aging effects for which they are credited.

3.0.3.4.3 Flow Blockage of Water-Based Fire Protection System Piping

<u>Summary of Technical Information</u>. The staff's evaluation of the Fire Water System Program prior to the issuance of the applicant's responses to RAIs 3.0.3-1 is documented in NUREG-1930, Section 3.0.3.2.8. In its response associated with the Fire Water System Program, dated December 16, 2014 (ADAMS Accession No. ML14365A069), the applicant stated that it would conduct the tests and inspections recommended in LR-ISG-2012-02, with exceptions as noted below. The applicant also stated that the program would manage aging effects associated with the fire water storage tanks. The applicant further stated: (a) portions of the fire protection-water system that are normally dry, periodically subject to flow, and cannot be drained or allow water to collect will be subject to augmented testing; and (b) if visual inspections detect, "appreciable localized corrosion (e.g., pitting) beyond a normal oxide layer," followup wall thickness measurements will be conducted. The staff noted that the augmented testing and followup wall thickness measurements are consistent with LR-ISG-2012-02, AMP XI.M27, "Fire Water System Program." The applicant clarified that the timing for the 50-year criterion for sprinkler testing would commence from the time the sprinklers are placed in service versus installed. The staff noted that NFPA 25, "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," Section 5.3.1.1, also cites the in-service time for the 50-year testing criterion. References to NFPA 25 are to the 2011 Edition.

In its response, the applicant added nine new exceptions, Exception Nos. 2 through 10. The staff's evaluation follows. In addition to reviewing the response to RAIs, the staff conducted a supplemental audit on February 23-25, 2016 (ADAMS Accession No. ML16133A459).

<u>*Exception 2*</u>. As amended by letter dated December 16, 2014, LRA Section B.1.14 includes an exception to the "detection of aging effects" program element. In this exception the applicant stated that the emergency diesel generator sprinklers will be inspected every 18 months in lieu of annually. The applicant also stated that testing every 18 months has been "effective at maintaining component intended functions."

The staff reviewed this exception against the corresponding program element in LR-ISG-2012-02, AMP XI.M27, and finds it acceptable because: (a) the applicant stated that the 18-month inspection interval has not resulted in a loss of intended functions in the past and (b) there are a sufficient number of sprinklers installed in commercial nuclear power plants to establish an adverse performance trend, even with plant-specific inspections being completed on an 18-month basis rather than annually.

<u>*Exception 3*</u>. As amended by letter dated December 16, 2014, LRA Section B.1.14 includes an exception to the "detection of aging effects" program element. In this exception the applicant stated that "[t]he deluge valve for the IP2 primary Auxiliary Building exhaust, Containment Building purge exhaust, and Containment Building pressure relief charcoal units are tested each

refueling outage, which is every 2 years." The applicant also stated that testing is only feasible during outages and the 24-month cycle has been, "effective at maintaining component intended functions."

The staff reviewed this exception against the corresponding program element in LR-ISG-2012-02, AMP XI.M27, and finds it acceptable because, although NFPA 25 Section 13.4.3.2.2 states that deluge valves should be tested annually, Sections 13.4.3.2.2.3 and 13.4.3.2.2.4 allow a longer interval between tests (up to 3 years), if discharging water will potentially damage operating energized equipment.

Exception 4. As amended by letter dated December 16, 2014, LRA Section B.1.14 includes an exception to the "detection of aging effects" program element. In this exception, the applicant stated that when conducting visual sprinkler inspections, it will not inspect for sprinkler orientation, foreign material, physical damage, and paint.

The staff reviewed this exception against the corresponding program element in LR-ISG-2012-02, AMP XI.M27, and finds it acceptable because the excluded inspection results are not associated with aging effects.

Exception 5. As amended by letter dated August 18, 2015 (ADAMS Accession No. ML15236A017), LRA Section B.1.14 includes an exception to the "detection of aging effects" program element. In this exception, the applicant stated that when degraded coatings are detected on the interior surfaces of the fire water storage tanks, it might not conduct adhesion testing in accordance with ASTM D 3359, "Standard Test Methods for Measuring Adhesion by Tape Test." The applicant stated that this test would not be conducted because it is destructive to the coatings and variability of test results can occur. The applicant also stated that it performs holiday testing and ultrasonic thickness testing.

The staff reviewed this exception against the corresponding program element in LR-ISG-2012-02, AMP XI.M27, and did not find it acceptable because the applicant did not propose an alternative to adhesion testing or state a basis for why adhesion testing does not need to be conducted beyond stating that holiday testing and ultrasonic thickness testing will be conducted if coating defects are detected. Holiday testing and ultrasonic thickness testing would not detect potential peeling, delamination, or blistering, or the extent of these aging mechanisms. By letter dated May 4, 2015 (ADAMS Accession No. ML15071A101), the staff issued RAI 3.0.3-6 requesting that the applicant state how potential peeling, delamination, or blistering, or the extent of these aging mechanisms, would be detected by holiday testing or ultrasonic wall thickness measurements.

In its response dated August 18, 2015, the applicant stated that a fire water tank with degraded coatings would only be returned to service if blistering is evidenced by a few small intact blisters that are completely surrounded by coating bonded to the substrate and there is no peeling or delamination. The applicant enhanced the Fire Water System Program (Enhancement 25) to state that the following inspections or tests would be conducted to determine the extent of coating defects when there is evidence of cracking, peeling, blistering, delamination, rusting, or flaking: (a) lightly tapping or scraping the coating; (b) wet-sponge or dry film thickness testing; (c) adhesion testing in accordance with ASTM D 3359, D 4541, "Standard Test Method for Pull-Off Strength of Coatings Using Portable Adhesion Testers," or other method endorsed by RG 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants"; and (d) UT when there is evidence that pitting or corrosion exists.

The applicant also enhanced the Fire Water System Program (Enhancement 26) to state that before returning a fire water tank to service when coating defects are detected, the following actions would be taken: (a) blistering in excess of a few small intact blisters not completely surrounded by coating bonded to the surface will be removed, (b) delaminated or peeled coatings will be removed, (c) adhesion testing in accordance with RG 1.54 is conducted to verify that the exposed underlying coating is securely bonded to the substrate, (d) the outer coating is feathered and an adhesion test is conducted in accordance with RG 1.54 in three locations on the remainder of the layer to ensure that it is securely bonded to the next layer of coating, (e) UT testing is conducted in the vicinity of pitting or corrosion, (f) an evaluation is conducted to ensure that downstream flow blockage is not a concern, and (g) a followup inspection is conducted within 2 years and every 2 years after that until the coating is repaired, replaced, or removed.

The staff finds the applicant's response and exception acceptable because the inspections, tests, corrective actions, and evaluation described in Enhancements 25 and 26 are effective means to detect the extent of degradation and the actions taken before returning a fire water tank to service with degraded coatings are consistent with the "corrective actions" program element of AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks." The staff's concern described in RAI 3.0.3-6 is resolved.

Exception 6. As amended by letter dated August 18, 2015, LRA Section B.1.14 includes an exception to the "detection of aging effects" program element. In this exception, the applicant stated that vacuum box testing (in accordance with NFPA 25 Section 9.7.2 (6)) of the bottom of the fire water tanks may not be possible if the tank bottom is uneven. The applicant also stated that the control room continuously monitors (as well as alarm capability) the capacity of the fire water storage tanks. In addition, leakage in excess of the jockey pump capacity would be apparent to the operating staff. The applicant further stated that corrective actions would be conducted to identify and correct the source of leakage.

The staff noted that the purpose of conducting vacuum box testing on tank bottom welds is to detect weld degradation that would not be detectable to the eye without the benefit of the vacuum affecting the soap bubble solution applied for detection. The staff also notes that NFPA 25 Section 9.2.7(6) exempts tanks without flat bottoms from the vacuum box testing. The staff reviewed this exception against the corresponding program element in LR-ISG-2012-02, AMP XI.M27, and finds it acceptable because the applicant has two means to detect leakage in its fire water storage tanks—control room indications and alarms and monitoring of jockey pump conditions—and, as stated in Enhancement 9 below, the applicant will conduct testing and measure the thickness of any identified corroded areas at least once every 5 years.

Exception 7. As amended by letter dated December 16, 2014, LRA Section B.1.14 includes an exception to the "detection of aging effects" program element. In this exception, the applicant stated that it does not perform main drain testing on all standpipes and risers. The applicant also stated that it will perform main drain testing on "20 percent of the testable automatic standpipes and risers with at least one main drain test per building."

The staff noted that several GALL Report AMPs recommend a 20 percent sample size to conduct a representative number of inspections (e.g., AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," as modified by LR-ISG-2012-02). The staff reviewed this exception against the corresponding program element in LR-ISG-2012-02, AMP XI.M27, and finds it acceptable because the applicant will use the same extent of inspections as recommended in several GALL Report AMPs and by conducting at least one test per building, variability in system conditions can be detected.

Exception 8. LRA Section B.1.14 included an exception to the “detection of aging effects” program element. In this exception, the applicant stated that it does not perform the preaction valve testing with the control valve fully open for the electric tunnels as specified by NFPA 25 Section 13.4.3.2.3. The applicant also stated that performing the testing with a closed or throttled valve reduces the amount of water that enters normally dry preaction piping. This exception was subsequently deleted by the applicant, by letter dated August 18, 2015, in which the applicant also added Enhancement 27 to its Fire Water System Program.

In its review of LRA Exception 8, the staff reviewed this exception against the corresponding program element in LR-ISG-2012-02, AMP XI.M27, and did not find it acceptable. Specifically, (a) the staff found that it lacked sufficient information to conclude that adequate flow to detect potential flow blockage will be achieved during the test, and (b) NFPA 25 Section 13.4.3.2.2.5 allows air to be used as a test medium when the nature of the protected property is such that water cannot be discharged. By letter dated May 4, 2015, the staff issued RAI 3.0.3-7 requesting that the applicant state and justify the basis for why flow rates sufficient to detect flow blockage will be achieved during preaction valve testing.

In its response dated August 18, 2015, the applicant enhanced (Enhancement 27) the Fire Water System Program to remove a sprinkler head at the end of a branch line to perform an air test when cycling the electric tunnel preaction valve in order to detect potential downstream flow blockage.

As further discussed below regarding Enhancement 27, the staff finds the applicant’s response and Enhancement 27 acceptable because air flow testing can detect potential flow blockage, and this method is cited in NFPA 25 Section 13.4.3.2.2.5. As such, the applicant’s enhancement is consistent with LR-ISG-2012-02, AMP XI.M27. The staff’s concern described in RAI 3.0.3-7 is resolved.

Exception 9. As amended by letter dated December 16, 2014, LRA Section B.1.14 includes an exception to the “detection of aging effects” program element. In this exception, the applicant stated that it does not conduct an internal inspection for blockage of the normally dry fire water piping downstream of the deluge valves for the transformers. The applicant also stated that it conducts full flow testing of the deluge systems for the transformers every refueling outage.

The staff reviewed this exception against the corresponding program element in LR-ISG-2012-02, AMP XI.M27, and finds it acceptable because the full flow testing of the deluge system is an effective means of detecting flow blockage.

Exception 10. As amended by letter dated December 16, 2014, LRA Section B.1.14 includes an exception to the “detection of aging effects” program element. In this exception, the applicant stated that it does not inspect open sprinkler heads for signs of leakage because for open heads, the leakage is as a result of a leaking upstream deluge or control valve. Leakage of deluge or control valve trim is due to degradation of active components of the valve.

The staff reviewed this exception against the corresponding program element in LR-ISG-2012-02, AMP XI.M27, and finds it acceptable because, as stated by the applicant, degradation of active parts of components (i.e., valve trim) is not subject to an AMR.

In its response, the applicant revised two existing enhancements, Enhancements 2 and 3, deleted existing Enhancement 4, and added 23 new enhancements, Enhancements 5 through 27. The staff's evaluation follows.

Enhancement 2. As amended by letter dated December 16, 2014, the applicant committed to implement the following enhancement to the "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements at IP2 and IP3. The changes to the enhancement state that the internal inspections of the foam-based fire suppression tank will be conducted every 10 years and the acceptance criteria will be no abnormal corrosion.

The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2012-02, AMP XI.M27, and finds it acceptable in part because, when it is implemented, it will enhance the program to include inspection intervals for the foam-based fire suppression tank consistent with NFPA 25 Table 11.1.1.2. However, the staff lacked sufficient information to complete its evaluation of the acceptance criteria portion of this enhancement because abnormal corrosion is not described. By letter dated May 4, 2015, the staff issued RAI 3.0.3-8 requesting that the applicant state the magnitude of corrosion that would be considered unacceptable during the inspection of internal surfaces of foam-based fire suppression tanks.

In its response dated August 18, 2015, the applicant stated that its letter of December 16, 2014, had stated "[i]n addition, visual inspection results that identify excessive accumulation of corrosion products and appreciable localized corrosion (e.g., pitting) beyond a normal oxide layer will be entered into the corrective action program, and a followup volumetric wall thickness examination will be performed." The applicant also stated that this acceptance criteria applies to the internal visual inspections of the foam-based fire suppression tanks.

The staff noted that the above quoted statement was associated with internal pipe wall inspections based on the editing of the program description for the Fire Water System Program. The staff finds the applicant's response and enhancement acceptable because the above quoted criteria can be equally effective at determining the need to conduct followup wall thickness evaluations. The staff's concern described in RAI 3.0.3-8 is resolved.

Enhancement 3. As amended by letter dated December 16, 2014, the applicant committed to implement the following enhancement to the "detection of aging effects" program element at IP2 and IP3. The change to the enhancement entails referencing NFPA 25 Section 5.3.1 for replacement or testing of closed sprinkler heads.

The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2012-02, AMP XI.M27, and finds it acceptable because it is consistent with LR-ISG-2012-02, AMP XI.M27, Table 4a, "Fire Water System Inspection and Testing Recommendations," which recommends use of NFPA 25 Section 5.3.1 for replacement or testing of closed sprinkler heads.

Enhancement 4. As amended by letter dated December 16, 2014, the applicant deleted this enhancement. This enhancement addressed periodic wall thickness measurements of fire protection-water piping. The staff finds the deletion of this enhancement acceptable because LR-ISG-2012-02, AMP XI.M27, no longer recommends wall thickness measurements as an alternative to recommended inspections and tests.

Enhancement 5. As amended by letter dated December 16, 2014, the applicant committed to implement the following enhancement to the "detection of aging effects" program element at IP2 and IP3. The enhancement states that sprinkler heads will be replaced if they show signs of abnormal corrosion, excessive loading, leakage, or if the glass bulb heat responsive element is empty.

The staff noted that NFPA 25 Sections 5.2.1.1.2(2) and 5.2.1.1.4 state that sprinklers that exhibit corrosion, not "abnormal corrosion," should be replaced. By letter dated May 4, 2015, the staff issued RAI 3.0.3-9 requesting that the applicant describe the degree of corrosion that would be found acceptable during a visual inspection of sprinkler heads.

In its response dated August 18, 2015, the applicant revised Enhancement 5 to state that sprinkler heads would be replaced if they show signs of corrosion, loading, or if the glass bulb heat responsive element is found empty." The enhancement also states that "[i]n lieu of replacing a loaded sprinkler head, sprinklers that are loaded with a coating of dust can be cleaned with compressed air or by vacuum provided that the equipment does not touch the sprinkler head."

The staff noted that NFPA 25 Section A.5.2.1.1.2(5) states that "[i]n lieu of replacing sprinklers that are loaded with a coating of dust, it is permitted to clean sprinklers with compressed air or by a vacuum provided that the equipment does not touch the sprinkler." The staff finds the applicant's response and enhancement acceptable because the applicant revised its acceptance criteria to be consistent with NFPA 25 Sections 5.2.1.1.2(2) and 5.2.1.1.4 and LR-ISG-2012-02, AMP XI.M27. The staff's concern described in RAI 3.0.3-9 (sprinkler head portion) is resolved.

Enhancement 6. As amended by letter dated December 16, 2014, the applicant committed to implement the following enhancement to the "detection of aging effects" program element at IP2. The enhancement states that for the primary Auxiliary Building exhaust, Containment Building purge exhaust, and Containment Building pressure relief charcoal units, testing will be capable of detecting partial flow blockage during air flow testing.

The staff finds the applicant's response and enhancement acceptable because detection of partial flow blockage can ensure that the intended function of the spray system nozzles is met. In addition, NFPA 25 Section 13.4.3.2.2.5(A) allows for testing with air flow in lieu of water when the protected component could be damaged by water spray.

Enhancement 7. As amended by letter dated December 16, 2014, the applicant committed to implement the following enhancement to the "detection of aging effects" program element at IP2. The enhancement states that the charcoal filter unit nozzles will be inspected for abnormal corrosion when the charcoal is replaced. In conjunction with the staff's evaluation of Enhancement 5, by letter dated May 4, 2015, the staff issued RAI 3.0.3-9 requesting that the applicant describe the degree of corrosion that would be found acceptable during the inspection of a charcoal filter nozzle.

In its response dated August 18, 2015, the applicant stated:

> It has been determined the IP3 charcoal filter fire suppression systems and IP2 primary auxiliary building and containment ventilation charcoal filter fire suppression systems do not have nozzles within the charcoal filter units. Fire water is distributed through a series of holes in the piping within the charcoal filter beds. The IP2 technical support center charcoal filter fire suppression system unit has nozzles within the charcoal filtration units.

The applicant revised Enhancement 7 to state that the water distribution piping inside the charcoal filter units will be inspected for corrosion when charcoal is replaced. The enhancement also states that if the amount of corrosion exceeds normal surface corrosion, the condition will be entered into the corrective action program.

The staff noted that NFPA 25 Section 13.4.3.2.2.4 states that the frequency of full flow deluge testing should not exceed 3 years. The staff also noted that in Exception 3, the applicant stated that deluge testing for the IP2 charcoal units will occur every 2 years. In addition, Enhancement 18 states that the IP3 charcoal units will be tested in accordance with NFPA 25 Section 13.4.3.2.2, and the associated substeps. During the supplemental audit, the staff reviewed the charcoal unit deluge valve test procedure. The staff noted that it is not practical to test the deluge system with water because the water flow would degrade the performance of the charcoal units. In addition, the flow distribution header is embedded in the charcoal bed and therefore it is not possible to observe air flow through the distribution holes. In lieu of these methodologies, the applicant's procedure pressurizes the header with air, opens the deluge valve, and confirms that the header depressurizes. The staff finds this method consistent with the testing described in NFPA 25 because the header depressurization provides reasonable assurance that flow blockage will not occur. The staff finds the applicant's response and enhancement acceptable because testing every 2 years, inspecting the nozzles whenever the charcoal media is replaced, and the acceptance criteria of no corrosion beyond normal surface corrosion can be sufficient to ensure that flow blockage will not prevent the charcoal deluge systems from performing their CLB intended function. The staff's concern described in RAI 3.0.3-9 (charcoal filter portion) is resolved.

Enhancement 8. As amended by letter dated December 16, 2014, the applicant committed to implement the following enhancement to the "detection of aging effects" program element at IP2 and IP3. The enhancement states that main drain testing will be conducted on 20 percent of the testable automatic standpipes with at least one main drain test being conducted in each building. The staff's evaluation of the applicant's conduct of main drain testing is documented in Exception 7, above.

Enhancement 9. As amended by letter dated August 18, 2015, the applicant committed to implement the following enhancement to the "detection of aging effects" program element. The enhancement states that the interior and exterior of the fire water storage tanks will be inspected in accordance with NFPA 25 Sections 9.2.5.5, 9.2.6 and 9.2.7, with the exception of 9.2.7(1) and 9.2.7(6). In regard to 9.2.7(1), it will conduct adhesion testing in accordance with standards recommended in RG 1.54. It also states that in lieu of conducting vacuum box testing in accordance with Section 9.2.7(6), it will conduct testing and measure thickness of any identified corroded areas at least once every 5 years. The staff finds the uses of adhesion testing in accordance with standards recommended in RG 1.54 acceptable because these standards are endorsed by the staff and can be equally effective as the standard referenced in NFPA 25. The staff's evaluation of not conducting vacuum box testing is documented in Exception 6, above.

Enhancement 10. As amended by letter dated December 16, 2014, the applicant committed to implement the following enhancement to the "detection of aging effects" program element at IP2. The enhancement states that the deluge system for the boric acid building filter units will be inspected and tested every 2 years.

The staff finds the applicant's response and enhancement acceptable because the units will be inspected and tested more frequently than every 3 years as cited in NFPA 25 Section 13.4.3.2.2.4.

Enhancement 11. As amended by letter dated December 16, 2014, the applicant committed to implement the following enhancement to the "detection of aging effects" program element at IP2 and IP3. The enhancement states that air flow testing will be conducted each refueling outage through the foam system open head nozzles to ensure there is no blockage. The applicant also stated that if blockage is detected, the system will be cleaned and retested.

The staff noted that LR-ISG-2012-02, AMP XI.M27, Table 4a, recommends that an operational discharge pattern test be conducted annually in accordance with NFPA 25 Section 11.3.2.6. Table 4a footnote 6 states that "[w]here the nature of the protected property is such that foam cannot be discharged, the nozzles or open sprinklers shall be inspected for correct orientation and the system tested with air to ensure that the nozzles are not obstructed." The staff did not find the applicant's response and enhancement acceptable because a justification was not provided for testing every refueling outage in lieu of annual testing. By letter dated May 4, 2015, the staff issued RAI 3.0.3.10 requesting that the applicant justify why testing the foam system open head nozzles every refueling outage in lieu of annually is acceptable.

In its response dated August 18, 2015, the applicant stated that in order to perform air flow testing the system is taken out of service. The applicant also stated that past testing has not revealed any obstructions or incorrect orientation of the nozzles.

The staff finds the applicant's response and enhancement acceptable because: (a) Table 4a footnote 6 allows air flow testing in lieu of discharging a foam solution, (b) cleaning and retesting the system if flow blockage is detected is consistent with NFPA 25 Section 11.3.2.6.2, and (c) based on past testing results, testing on a refueling outage interval provides reasonable assurance that flow blockage will not occur. The staff's concern described in RAI 3.0.3-10 is resolved.

Enhancement 12. As amended by letter dated December 16, 2014, the applicant committed to implement the following enhancement to the "detection of aging effects" program element at IP2 and IP3. The enhancement states that the strainers associated with the supply line to the electric tunnel and in the line downstream of the deluge valve for the primary Auxiliary Building exhaust and Containment Building purge filtration units will be removed, inspected for damage and corroded parts, and cleaned every 5 years, or after each flow test.

The staff finds the applicant's response and enhancement acceptable because it is consistent with NFPA 25 Section 10.2.1.7 and inspecting the screens is an effective means to detect potential flow blockage after flow testing because loose corrosion products, if present in the system, will transport during a flow test.

Enhancement 13. As amended by letter dated December 16, 2014, the applicant committed to implement the following enhancement to the "detection of aging effects" program element at IP2 and IP3. The enhancement states:

> Revise IP2 and IP3 Fire Water System Program procedures to perform an internal inspection of wet fire water system piping conditions every five years, or after an extended shutdown of greater than one year, by opening a flushing connection at the end of one main and by removing a closed sprinkler toward the

> end of one branch line for the purpose of inspecting the interior for evidence of loss of material and the presence of foreign organic and inorganic material that could result in flow obstructions or blockage of sprinkler head or nozzles. In the event there are multiple wet pipe systems in a structure, one third will be inspected every five years such that all systems will be inspected during each 15-year period. The procedures will include (1) guidance to perform an evaluation for MIC in the event tubercles or slime are identified, and (2) acceptance criteria that states "no abnormal debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged.) Corrective actions will specify that any signs of abnormal corrosion or blockage will be removed, the source and extent of condition determined and corrected, and entered into the corrective action program.

The staff finds the applicant's response and enhancement acceptable in part because the periodicity of inspections, method of inspection, evaluation of microbiologically-influenced corrosion (MIC), and associated acceptance criteria and corrective actions are consistent with NFPA 25 Section 14.2 and LR-ISG-2012-02, AMP XI.M27. However, a justification was not stated for inspecting one-third of the systems where there are multiple wet pipe systems in a building in lieu of every other system as specified in NFPA 25 Section 14.2. In addition, the applicant did not state whether all the systems in a building will be inspected if foreign organic or inorganic material is found in any system in that building. By letter dated May 4, 2015, the staff issued RAI 3.0.3-10 requesting that the applicant justify why testing one-third of the systems every 5 years and not testing all the systems in a building when foreign organic or inorganic material is found in any system in that building is sufficient to provide reasonable assurance that the wet fire water system piping and piping components will meet their CLB intended functions during the period of extended operation.

In its response dated August 18, 2015, the applicant stated that the wet pipe sprinkler systems are fabricated from the same material and exposed to the same water environment; therefore, the test results from one-third of the systems in each building are representative of the other systems. The applicant revised Enhancement 13 to state that if there are any signs of abnormal corrosion or blockage, the inspection scope will be expanded to include all of the wet pipe sprinklers systems in that building.

During the supplemental audit, the staff reviewed drawings, procedures, and the response to a scoping and screening RAI. Based on its review, the staff concluded that the only buildings with more than two in-scope sprinkler systems were the Diesel Generator buildings. Where there are one or two sprinkler systems in a building, inspecting one-third of the systems results in at least one system being inspected. During each inspection period, six systems will be inspected (IP2 Diesel Fire Pump Building, IP2 Diesel Generator Building, IP3 Turbine Building, IP3 Fire Pump House, IP3 auxiliary Boiler Feed Pump Room, and IP3 Diesel Generator Building) in lieu of the eight systems that would be inspected if NFPA 25 guidance were rounded up.

The staff finds the applicant's response and enhancement acceptable for buildings with two or less sprinkler systems because the NFPA 25 requirements are met. For the Diesel Generator buildings, the staff finds the enhancement acceptable because: (a) an adequate number of inspections will be conducted to provide input into the internal conditions of the piping systems, and (b) all of the systems are constructed of the same material and exposed to the same environment. The staff's concern described in RAI 3.0.3-10 is resolved.

Enhancement 14. As amended by letter dated December 16, 2014, the applicant committed to implement the following enhancement to the "detection of aging effects" program element at IP2. The enhancement states:

> Revise IP2 Fire Water System Program procedures to perform an internal inspection of dry piping every five years, or after an extended shutdown of greater than one year, for the preaction systems associated with the technical support center computer and uninterruptible power supply room, and the preaction system associated with the electric tunnels by removing a sprinkler toward the end of one branch line or using the inspectors test valve for the purpose of inspecting for the presence of foreign organic and inorganic material. The procedures will include (1) guidance to perform an evaluation for MIC in the event tubercles or slime are identified, and (2) acceptance criteria that states "no abnormal debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged.) Corrective actions will specify that any signs of abnormal corrosion or blockage will be removed, the source and extent of condition determined and corrected, and entered into the corrective action program.

The staff noted that NFPA 25 Section 14.2.2 (inspecting every other system) only applies to wet pipe systems. The staff finds the applicant's response and enhancement acceptable because the periodicity of inspections, method of inspection, evaluation of MIC, and associated acceptance criteria and corrective actions are consistent with NFPA 25 Section 14.2 and LR-ISG-2012-02, AMP XI.M27.

Enhancement 15. As amended by letter dated December 16, 2014, the applicant committed to implement the following enhancement to the "detection of aging effects" program element at IP2. The enhancement states:

> Revise IP2 Fire Water System Program procedures to perform an internal inspection of the most remote dry piping downstream of the deluge valves every five years, or after an extended shutdown of greater than one year, for the deluge systems associated with the primary auxiliary building, containment purge, containment ventilation, and boric acid building charcoal filters, and the foam deluge systems by removing a sprinkler toward the end of one branch line or using the inspectors test valve for the purpose of inspecting for the presence of foreign organic and inorganic material. The procedures will include (1) guidance to perform an evaluation for MIC in the event tubercles or slime are identified, and (2) acceptance criteria that states "no abnormal debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged.) Corrective actions will specify that any signs of abnormal corrosion or blockage will be removed, the source and extent of condition determined and corrected, and entered into the corrective action program.

The staff noted that NFPA 25 Section 14.2.2 for inspecting every other system only applies to wet pipe systems. The staff finds the applicant's response and enhancement acceptable because the periodicity of inspections, method of inspection, evaluation of MIC, and associated acceptance criteria and corrective actions are consistent with NFPA 25 Section 14.2 and LR-ISG-2012-02, AMP XI.M27.

Enhancement 16. As amended by letter dated December 16, 2014, the applicant committed to implement the following enhancement to the "detection of aging effects" program element at IP2 and IP3. The enhancement states seven criteria for conducting an obstruction evaluation (reference NFPA Section 14.3).

The staff finds the applicant's response and enhancement acceptable because the applicant will conduct an obstruction investigation based on the seven criteria listed in NFPA 25 Section 14.3 associated with age-related degradation.

Enhancement 17. As amended by letter dated December 16, 2014, the applicant committed to implement the following enhancement to the "detection of aging effects" program element at IP2 and IP3. The enhancement states that a wall thickness evaluation will be conducted when excessive accumulation of corrosion products or appreciable localized pitting beyond a normal oxide layer is detected.

The staff noted that LR-ISG-2012-02 states that "[w]hen visual inspections are used to detect loss of material, the inspection technique is capable of detecting surface irregularities that could indicate wall loss to below nominal pipe wall thickness due to corrosion and corrosion product deposition. Where such irregularities are detected, followup volumetric wall thickness examinations are performed." However, the staff agrees that wall loss below the nominal wall thickness value is an overly restrictive threshold because piping could have been supplied at nominal or below nominal wall thickness (e.g., many ASTM specifications allow piping to be 12-1/2 percent below nominal wall thickness) in the brand new condition. The staff finds the applicant's response and enhancement acceptable because indications of excessive accumulation of corrosion products or appreciable localized pitting beyond a normal oxide layer are effective criteria for detecting potential wall loss that should be followed up with a wall thickness evaluation.

Enhancement 18. As amended by letter dated December 16, 2014, the applicant committed to implement the following enhancement to the "detection of aging effects" program element at IP3. The enhancement states that water spray system No.11 charcoal filters associated with the containment purge exhaust, primary Auxiliary Building exhaust system, and containment pressure relief filtration units will be tested and inspected in accordance with NFPA 25 Section 13.4.3.2.2, and the associated substeps.

The staff finds the applicant's response and enhancement acceptable because the cited reference contains sufficient guidance for the frequency, method, acceptance criteria, and corrective actions consistent with LR-ISG-2012-02, AMP XI.M27.

Enhancement 19. As amended by letter dated December 16, 2014, the applicant committed to implement the following enhancement to the "detection of aging effects" program element at IP3. The enhancement states that hydrants will be flushed by fully opening the hydrant for a minimum of 1 minute and until the water is clear. It also states that the hydrant drainage time will be measured, and if it exceeds 60 minutes, the procedure will provide steps to correct the nonconforming condition (e.g., unclog the drain or pump out the hydrant).

The staff finds the applicant's response and enhancement acceptable because the test method, test duration, acceptance criteria, and corrective actions are consistent with LR-ISG-2012-02, AMP XI.M27.

Enhancement 20. As amended by letter dated December 16, 2014, the applicant committed to implement the following enhancement to the "detection of aging effects" program element at IP3. The enhancement states that an air flow test will be performed to ensure that spray patterns are not affected by flow blockage for the hydrogen seal oil unit, main boiler feed pump oil reservoir, main lube oil storage, and main lube oil reservoir foam deluge systems. It also states that when plugged nozzles are identified, the procedure will require that the nozzles are cleaned and retested.

The staff finds the applicant's response and enhancement acceptable because an air test is an acceptable alternative to conducting a water flow test as stated in NFPA 25 Section 13.4.3.2.2.5(A) and the corrective actions are consistent with Section 13.4.3.2.2.5(B).

Enhancement 21. As amended by letter dated December 16, 2014, the applicant committed to implement the following enhancement to the "detection of aging effects" program element at IP3. The enhancement states that the strainers associated with the electric tunnels and the containment purge exhaust system, primary Auxiliary Building exhaust system, and containment pressure relief filtration unit will be removed, cleaned, and inspected for damage and abnormal corrosion.

The staff finds the applicant's response and enhancement acceptable because inspecting strainers for damage and corrosion is consistent with NFPA 25 Section 10.2.1.7.

Enhancement 22. As amended by letter dated December 16, 2014, the applicant committed to implement the following enhancement to the "detection of aging effects" program element at IP3. The enhancement states:

> Revise IP3 Fire Water System Program procedure(s) to perform an internal inspection every five years of the remote normally dry portion of the preaction system associated with the electric tunnels by removing a sprinkler toward the end of one branch line or using the inspector test valve for the purpose of inspecting for the presence of foreign organic and inorganic material. The procedure that governs inspection of the normally dry piping will include (1) guidance to perform an evaluation for MIC in the event tubercles or slime are identified, and (2) acceptance criteria that states "no abnormal debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged.) Corrective actions will specify that any signs of abnormal corrosion or blockage will be removed, the source and extent of condition determined and corrected, and entered into the corrective action program.

The staff finds the applicant's response and enhancement acceptable because the periodicity of inspections, method of inspection, evaluation of MIC, and associated acceptance criteria and corrective actions are consistent with NFPA 25 Section 14.2 and LR-ISG-2012-02, AMP XI.M27.

Enhancement 23. As amended by letter dated December 16, 2014, the applicant committed to implement the following enhancement to the "detection of aging effects" program element at IP3. The enhancement states:

> Revise IP3 Fire Water System Program procedure(s) to perform an internal inspection every five years of the most remote dry piping downstream of the deluge valves in the deluge systems for the primary auxiliary building exhaust,

containment purge, containment pressure relief, and foam systems by removing a sprinkler toward the end of one branch line for the purpose of inspecting for the presence of foreign organic and inorganic material. The procedure that governs inspection of the normally dry piping will include (1) guidance to perform an evaluation for MIC in the event tubercles or slime are identified, and (2) acceptance criteria that states "no abnormal debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged.) Corrective actions will specify that any signs of abnormal corrosion or blockage will be removed, the source and extent of condition determined and corrected, and entered into the corrective action program.

The staff finds the applicant's response and enhancement acceptable because the periodicity of inspections, method of inspection, evaluation of MIC, and associated acceptance criteria and corrective actions are consistent with NFPA 25 Section 14.2 and LR-ISG-2012-02, AMP XI.M27.

The staff noted that as amended by letter dated December 16, 2014, LRA Section B.1.14 states "[i]n addition to NFPA codes, portions of the water-based fire protection system (a) that are normally dry but periodically subject to flow (e.g., dry-pipe or preaction sprinkler system piping and valves) and (b) that cannot be drained or allow water to collect are subject to augmented testing and inspections." However, neither LRA Section A.1.14 nor B.1.14 state what augmented testing will be conducted. In addition, the staff noted that there were no enhancements associated with this program requirement. By letter dated May 4, 2015, the staff issued RAI 3.0.3-12 requesting that the applicant state what augmented testing and inspections will be conducted for normally dry but periodically subject to flow (e.g., dry-pipe or preaction sprinkler system piping and valves) that cannot be drained or allow water to collect.

In its response dated August 18, 2015, the applicant stated: (a) that an inspection of periodically wetted dry fire water systems revealed that the piping is configured to drain properly, (b) plant-specific procedures require that the piping is drained before placing the piping back inservice, and (c) based on an enhancement to the Fire Water System Program, an air test is conducted when preaction and deluge valves are cycled to ensure that there is not blockage in the system. The applicant also stated that based on the above, no augmented inspections are required.

The staff noted that Enhancements 6 and 20 address air flow testing associated with various deluge systems and Enhancement 27 addresses air flow testing associated with the preaction system for the electric tunnel. However, the staff could not confirm that these are the only deluge and preaction systems at the station. Nevertheless, the staff finds the applicant's response acceptable because normally dry periodically wetted pipe should be drained after water has been in the system because the piping is configured to drain and plant-specific procedures require draining of the piping. If the water is drained from the pipe, accelerated corrosion should not occur and, therefore, the augmented testing recommended in LR-ISG-2012-02, AMP XI.M27 is not required. The staff's concern described in RAI 3.0.3-12 is resolved. RAI 3.0.3-13 requested that the applicant state the basis for not commencing the augmented inspections for normally dry but periodically wetted piping before December 31, 2019. Based on the response to RAI 3.0.3-12, RAI 3.0.3-13 is moot because no augmented testing is recommended in AMP XI.M42 for the configuration of piping at the applicant's station.

<u>*Enhancement 24*</u>. As amended by letter dated August 18, 2015, the applicant committed to implement the following enhancement to the "detection of aging effects" program element at IP2

and IP3. The enhancement states that the accessible portions of the water distribution piping inside the charcoal units will be inspected for corrosion. If the amount of corrosion exceeds normal surface corrosion, the degradation will be entered into the corrective action program. The staff finds the applicant's enhancement acceptable because, as documented in Enhancement 7, deluge testing for the charcoal filters is conducted consistent with LR-ISG-2012-02, AMP XI.M27, and these inspections can ensure that the piping inside the charcoal units is not experiencing unacceptable loss of material.

Enhancement 25. As amended by letter dated August 18, 2015, the applicant stated an enhancement to the "detection of aging effects" program element at IP2 and IP3. The enhancement and staff evaluation of the enhancement is documented in Exception 5, above.

Enhancement 26. As amended by letter dated August 18, 2015, the applicant stated an enhancement to the "detection of aging effects" program element at IP2 and IP3. The enhancement and staff evaluation of the enhancement is documented in Exception 5, above.

Enhancement 27. As amended by letter dated August 18, 2015, the applicant stated an enhancement to the "detection of aging effects" program element at IP2 and IP3. The enhancement and staff evaluation of the enhancement is documented in Exception 8, above.

Based on its review of the applicant's responses to RAIs 3.0.3-1, 3.0.3.4.3-1, 3.0.3.4.3-2, 3.0.3.4.3-3, 3.0.3.4.3-4, 3.0.3.4.3-5, 3.0.3.4.3-6,and 3.0.3.4.3-7, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of LR-ISG-2012-02, AMP XI.M27. The staff also reviewed the exceptions associated with the "detection of aging effects," program element, and their justifications, and finds that the AMP, with the exceptions, is adequate to manage the applicable aging effects. In addition, the staff reviewed the enhancements associated with the "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements and finds that, when implemented, they will make the AMP adequate to manage the applicable aging effects.

UFSAR Supplement. The staff reviewed this UFSAR supplement description of the Fire Water System Program, as amended by letter dated August 18, 2015, against the recommended description for this type of program described in SRP-LR Table 3.0-1, as revised by LR-ISG-2012-02. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program. The staff noted that the applicant committed (Commitment No. 8) to implement the enhancements as described above by December 31, 2019. Given that IP2 is beyond the expiration of its initial license period (September 2013) and IP3 is beyond its initial license period (December 2015), the staff questioned why the enhancements would not be implemented sooner than December 31, 2019. By letter dated July 7, 2015 (ADAMS Accession No. ML15170A456), the staff issued RAI 3.0.3-17 requesting that the applicant state and justify the basis for the implementation schedule for the enhancements to the Fire Water System Program.

In its response dated September 1, 2015 (ADAMS Accession No. ML15251A237), the applicant stated that the date was deemed reasonable because sufficient time is required to train and qualify individuals conducting coating/lining inspections of the fire water storage tanks, to revise plant-specific procedures to incorporate the acceptance criteria of LR-ISG-2013-01, and scheduling and conducting the inspections based on a two-year operating cycle. The applicant also stated that "[t]he existing Fire Water System Program includes periodic flushing, system performance testing, and inspections, including internal inspection of the surface condition of the fire water tanks."

The staff finds the applicant's response acceptable because it is reasonable to provide sufficient time to have plant-specific implementing procedures and training completed, as well as planning, scheduling, and conducting the inspection and tests; and the breadth of existing testing and inspections can provide current insights to the station staff with regard to the conditions of the internal surfaces of the fire water system. The staff's concern described in RAI 3.0.3-17 is resolved.

On the basis of its review of the applicant's Fire Water System Program, the staff finds 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 finds that the AMP, with the exceptions, is adequate to manage the applicable aging effects. Also, the staff reviewed the enhancements and confirmed that their implementation before the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.4.4 Revisions to the Scope and Inspection Recommendations of GALL Report AMP XI.M29, "Aboveground Metallic Tanks"

In its response associated with the Aboveground Steel Tanks Program, the applicant stated that the revised AMP is consistent with LR-ISG-2012-02. The applicant added the aging effect of cracking and expanded the inspections to address the aging effects associated with both the inside and outside surfaces of the tanks. Enhancement 3 was added to the program to provide the inspection details for visual and surface examinations. Exception 1 was added to the program stating that the timing of the program inspections will not be consistent with the ISG because of the date that the ISG was issued. The revised program also includes preventive measures to mitigate aging. The applicant removed the fire water storage tanks from the scope of this program.

The staff's evaluation of the changes to LRA Sections A.2.1.1, A.3.1.1, and B.1.1, Enhancement 3, and Exception 1, which are provided in the applicant's letter dated December 16, 2014 (ADAMS Accession No. ML14365A069), is documented in SER Section 3.0.3.2.1.

Based on its review of the applicant's response to RAIs 3.0.3-1, 3.0.3-14, and 3.0.3-15 the staff finds that the program is consistent with GALL Report AMP XI.M29, as amended by LR-ISG-2012-02, and is adequate to manage the aging effects for which it is credited.

3.0.3.4.5 Corrosion Under Insulation

<u>Summary of Technical Information in the Application</u>. In its response dated December 16, 2014 (ADAMS Accession No. ML14365A069), to RAI 3.0.3-1 associated with LR-ISG-2012-02, Section E, "Corrosion Under Insulation," the applicant revised the External Surfaces Monitoring Program and the Aboveground Steel Tanks Program to conduct periodic inspections of insulated components exposed to condensation or outdoor air.

Staff Evaluation. The applicant stated that none of the indoor in-scope insulated tanks operate below the dew point. In addition, all of the in-scope outdoor tanks have tightly adhering insulation. The applicant revised the External Surfaces Monitoring Program to:

- Perform periodic inspections during each 10-year period of the period of extended operation.
- Conduct initial and subsequent inspections of insulated components in accordance with the recommendations in LR-ISG-2012-02, AMP XI.M36, and AMP XI.M29, "Aboveground Metallic Tanks," (e.g., extent of inspections, method of inspection, and determination of the need to remove insulation in subsequent inspection).
- Select component inspection locations based on the likelihood of CUI.

Based on its review of the applicant's response to RAI 3.0.3-1, the staff finds that the program is consistent with GALL Report AMP XI.M36, as revised by LR-ISG-2012-02, and adequate to manage the aging effects for which it is credited.

The staff noted that the applicant revised LRA Sections A.2.1.1, A.2.1.10, A.3.1.1, A.3.1.10, B.1.1, and B.1.11. The staff's evaluation of these changes is documented in Sections 3.0.3.2.1, "Aboveground Steel Tanks Program" and 3.0.3.2.5, "External Surfaces Monitoring Program."

3.0.3.4.6 External Volumetric Examination of Internal Piping Surfaces of Underground Piping Removed from GALL Report AMP XI.M41, 'Buried and Underground Piping and Tanks'

Summary of Technical Information in the Application. In its response to External Volumetric Examination of Internal Piping Surfaces of Underground Piping Removed from GALL Report AMP XI.M41, "Buried and Underground Piping and Tanks," dated December 16, 2014 (ADAMS Accession No. ML14365A069), the applicant stated that there are no changes to the LRA to account for the guidance from LR-ISG-2012-02 for this section because it credits other programs.

Staff Evaluation. Based on its review of the applicant's response to RAI 3.0.3-1, the staff finds the proposal to not account for the guidance from this section of LR-ISG-2012-02 acceptable because other programs are being credited and provide reasonable assurance that the intended function will be maintained throughout the period of extended operation.

3.0.3.4.7 Specific Guidance for Use of the Pressurization Option for Inspecting Elastomers in GALL Report AMP XI.M38

Summary of Technical Information in the Application. In its response to Specific Guidance for Use of the Pressurization Option for Inspecting Elastomers in GALL Report AMP XI.M38, dated December 16, 2014 (ADAMS Accession No. ML14365A069), the applicant stated that it does not use hydrotesting in the programs for which this method is credited. As a result, there are no changes to the LRA to account for guidance from LR-ISG-2012-02 for this section.

Staff Evaluation. Based on its review of the applicant's response to RAI 3.0.3-1, the staff finds the applicant's proposal to not credit the guidance for this section from LR-ISG-2012-02 acceptable because it is not applicable, as demonstrated in the LRA and UFSAR.

3.0.3.4.8 Key Miscellaneous Changes to the GALL Report and SRP-LR in LR-ISG-2012-02

Summary of Technical Information in the Application. In its response to Key Miscellaneous Changes to the GALL Report and SRP-LR in LR-ISG-2012-02, dated December 16, 2014, the applicant stated that the only potential item with impact at IPEC was for reducing thermal insulation resistance to jacketed insulation. Since piping insulation is not credited for thermal insulation at IPEC, no changes to the LRA were made to account for the guidance in LR-ISG-2012-02, Section H.

Staff Evaluation. Based on its review of the applicant's response to RAI 3.0.3-1, the staff finds the proposal to not account for the guidance from this section of LR-ISG-2012-02 acceptable because the items from this section are not applicable, as demonstrated in the LRA, UFSAR, and operating experience. In addition, the applicant does not credit jacketed insulation as thermal resistance, which makes the Key Miscellaneous Changes section to LR-ISG-2012-02 have no impact on the LRA.

3.0.3.5 Changes to the LRA To Address LR-ISG-2016-01

The staff issued LR-ISG-2016-01, "Changes to Aging Management Guidance for Various Steam Generator Components," on December 7, 2016 (81 FR 88276), to address changes to GALL Report AMP XI.M19, "Steam Generators," and AMR items for steam generator components. The staff's evaluations related to LR-ISG-2016-01 are documented in Sections 3.0.3.2.14, 3.1.2.1, and 3.1.2.2.16.

3.1 Aging Management of Reactor Vessel, Internals, and Reactor Coolant System

3.1.2 Staff Evaluation

3.1.2.1 AMR Results Consistent with the GALL Report

The staff's evaluation of the applicant's aging management for steam generator nickel alloy divider plate assemblies is documented in Section 3.1.2.1 of NUREG-1930, Supplement 1, August 2011 (ADAMS Accession No. ML11242A215). These divider plate assemblies exposed to reactor coolant are fabricated with Alloy 600 type materials, which are susceptible to PWSCC. The following safety evaluation supplements Section 3.1.2.1 of NUREG-1930, Supplement 1.

As addressed in Section 3.1.2.1 of NUREG-1930, Supplement 1, the applicant committed to perform inspections of steam generator divider plate assemblies for assessing the condition of the components (Commitment No. 41). These inspections are intended to confirm the effectiveness of the Water Chemistry – Primary and Secondary Program to manage cracking due to PWSCC for the divider plate assemblies. These inspections are also intended to confirm that potential PWSCC in these components does not affect the integrity of adjacent RCPB components such as steam generator tubesheets and channel heads.

By letter dated January 17, 2017 (ADAMS Accession No. ML17023A209), the applicant submitted the information regarding its action on Commitment No. 41. In the letter, the applicant indicated that Commitment No. 41 was eliminated because it was no longer necessary based on the new guidance in LR-ISG-2016-01.

In its letter, the applicant also referred to the following guidance in LR-ISG-2016-01: For units with divider plate assemblies fabricated with Alloy 600 or Alloy 600 weld materials, if the analyses performed by the industry (EPRI Report 3002002850) are applicable and bounding for the unit, the primary Water Chemistry Program is supplemented with a general visual inspection of the steam generator channel head (as part of the Steam Generator Program). The purpose of the visual inspection is to identify rust stains or other abnormal conditions that could indicate the presence of cracking (e.g., distortion of divider plates). The general visual inspection is performed on each steam generator at least every 72 effective full-power months or every third refueling outage, whichever results in more frequent inspections.

As discussed in LR-ISG-2016-01, the staff noted that the industry analyses in EPRI Report 3002002850 assess the potential initiation and propagation of PWSCC and its impact on the structural integrity of steam generator channel heads. These analyses take into account material's resistance to PWSCC (e.g., resistance of Alloy 690) and steam generator loading conditions. The analyses conclude that PWSCC in the divider plate assemblies is highly unlikely to affect the integrity of other pressure boundary components (e.g., the channel head and tube-to-tubesheet welds).

The applicant's letter further indicates that, in parallel with the staff's finalization of LR-ISG-2016-01, EPRI issued Information Letter SGMP-IL-16-02, "Changes to Aging Management Guidance for Steam Generator Channel Head Components," on October 10, 2016. The applicant indicated that SGMP-IL-16-02 informed licensees that EPRI Report 3002002850 and LR-ISG-2016-01 may be used as a basis to update AMPs and activities for steam generator head components made with materials susceptible to PWSCC. The applicant also indicated that SGMP-IL-16-02 provides a checklist that reflects the bounding conditions considered in EPRI Report 3002002850 and other related EPRI technical reports in relation to divider plate assemblies. The applicant indicated that the checklist can be used to demonstrate that the industry analyses bound the conditions of the applicant's steam generators.

In addition, the January 17, 2017, letter provides proprietary information related to divider plate assemblies in accordance with the EPRI checklist to confirm that the industry analyses are applicable and bounding for the conditions of the steam generators and their divider plate assemblies at IP2 and IP3. In the submitted information related to divider plate assemblies, the applicant included component dimensions, design features, materials of fabrication, and design and transient loads as well as the comparisons of these conditions with the bounding conditions analyzed in the industry analyses.

In its review, the staff noted that Tables 4-2 and 4-3 of EPRI Report 3002002850 identify the turbine roll test as one of the bounding thermal transients for the industry analyses. In comparison, LRA Tables 4.3-1 and 4.3-2 describe design transients for ASME Code Class 1 fatigue analysis for IP2 and IP3, respectively. LRA Table 4.3-1 indicates that the number of turbine-roll-test cycles analyzed for IP2 is 20 cycles. LRA Table 4.3-2 indicates that the turbine-roll-test transient is not a design transient for IP3. The staff found the following concerns related to the applicant's determination that the loading conditions at IP2 and IP3 are bounded by the industry analyses (EPRI Report 3002002850).

- The number of turbine-roll-test cycles analyzed in EPRI Report 3002002850 is less than that analyzed for IP2 in LRA Table 4.3-1 (i.e., 20 cycles). This indicates that the loading conditions analyzed in the EPRI report for this transient may not bound the IP2 loading conditions.

- Given that LRA Table 4.3-2 does not identify the turbine roll test as an IP3 design transient for ASME Code Class 1 fatigue analysis, it is not clear how the applicant ensures the loading conditions at IP3 are bounded by those analyzed in EPRI Report 3002002850 in terms of the turbine-roll-test transient.

By letter dated April 19, 2017 (ADAMS Accession No. ML17088A327), the staff issued RAI B.1.35-1 requesting that the applicant justify why the IP2 steam generator loading conditions are bounded by those analyzed in EPRI Report 3002002850 even though the number of turbine-roll-test cycles analyzed in the EPRI report is less than that analyzed for IP2 in LRA Table 4.3-1. The staff also requested that the applicant discuss how it ensures that the loading conditions at IP3 are bounded by those analyzed in EPRI Report 3002002850 in terms of the turbine-roll-test transient.

In its letter dated May 19, 2017 (ADAMS Accession No. ML17145A288), the applicant clarified that a turbine roll test is a test performed during initial hot functional testing prior to commercial plant operation. With respect to the IP2 turbine-roll-test cycles, the applicant indicated that its cycle counting (as part of the Fatigue Monitoring Program) conservatively assumes that one turbine roll test was performed. The applicant also clarified that, because the steam generators at IP2 were replaced in 2000, and the turbine-roll-test transient only occurs during plant hot functional testing, the IP2 replacement steam generators have not experienced the transient and there is no plan to perform any additional turbine roll tests at IP2 during the remaining operating life.

In addition, the applicant indicated that it has revised IP2 cycle counting to reduce the number of allowable turbine roll tests to be consistent with the EPRI analysis. Based on the discussion above, the applicant concluded that the loading conditions at IP2 are bounded by those analyzed in EPRI Report 3002002850.

In its review, the staff finds the applicant's response regarding IP2 turbine-roll-test cycles acceptable because the applicant confirmed that (1) these transients occur only during plant hot functional test prior to commercial operation, (2) the IP2 replacement steam generators have not experienced a turbine-roll-test transient, (3) there is no plan for an additional turbine roll test at IP2, and (4) the number of allowable turbine roll tests at IP2 was reduced to be consistent with the EPRI analysis.

In its letter dated May 19, 2017, the applicant also addressed the turbine-roll-test transient of IP3. The applicant indicated that, because the turbine-roll-test transient at IP3 was not tracked before submittal of the LRA, the transient was not included in LRA Table 4.3-2. The applicant also stated that turbine-roll-test cycles have been added to the IP3 cycle counting. The applicant further indicated that its cycle counting conservatively assumes that five turbine roll tests were performed at IP3.

In addition, the applicant indicated that IP3 has no plans to perform any additional turbine roll tests during its remaining operating life. The applicant also indicated that the cycle counting procedure has a limit of five turbine-roll-test transient cycles for IP3 and, therefore, IP3 is bounded by the EPRI analysis. The applicant further indicated that, because the steam generators at IP3 were replaced in 1989, and the turbine-roll-test transient only occurs during plant hot functional testing, the IP3 replacement steam generators have not experienced and will not experience a turbine-roll-test transient.

In its review, the staff finds the applicant's response regarding IP3 turbine-roll-test cycles acceptable because the applicant confirmed that (1) these transients occur only during plant hot functional test prior to the commercial operation, (2) IP3 replacement steam generators have not experienced a turbine-roll-test transient, (3) there is no plan for an additional turbine roll test at IP3, (4) turbine-roll-test cycles have been added to the IP3 cycle counting, and (5) the cycle counting procedure has a limit of five turbine-roll-test transient cycles for IP3.

Based on the discussion above, the staff finds that the conditions of IP2 and IP3 steam generators, including loading conditions, are bounded by those analyzed in EPRI Report 3002002850, and, therefore, there is reasonable assurance that potential PWSCC in divider plate assemblies does not affect the integrity of the steam generator RCPB. The concern described in RAI B.1.35-1 is resolved.

The staff's evaluation of the Steam Generator Integrity Program is documented in SER Section 3.0.3.2.14. As previously discussed, the applicant identified an enhancement to the Steam Generator Integrity Program that applicable procedures are revised to specify general visual inspections of the steam generator channel heads, consistent with the guidance in LR-ISG-2016-01. In addition, the staff's evaluation of the Water Chemistry Control – Primary and Secondary Program is documented in Section 3.0.3.2.16 of NUREG-1930, Volume 2, November 2009 (ADAMS Accession No. ML093170671).

In its review, the staff finds that the Steam Generator Integrity Program (with the program enhancement) and Water Chemistry Control – Primary and Secondary Program are sufficient to provide adequate aging management for the divider plate assemblies susceptible to PWSCC because (1) the applicant confirmed that, consistent with LR-ISG-2016-01, the conditions of the steam generators are bounded by those analyzed in EPRI Report 3002002850 such that a plant-specific program is not necessary for the aging management; (2) the Steam Generator Integrity Program includes periodic visual inspections of channel head interior areas that can identify signs of cracking due to PWSCC in divider plate assemblies (e.g., rust stains, gross cracking, distortion of divider plates, and cracking breach); (3) these inspections can confirm the integrity of RCPB components such as channel heads and tubesheets adjacent to the divider plate assemblies; and (4) the Water Chemistry Control – Primary and Secondary Program controls the levels of chemical species and contaminants within acceptable ranges to minimize environmental effects promoting PWSCC.

Based on its review, the staff finds that the applicant has demonstrated that the effects of aging for the divider plate assemblies will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation is Recommended

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

The staff's evaluation of the applicant's aging management for steam generator nickel alloy tube-to-tubesheet welds is documented in Section 3.1.2.2.16(1) of NUREG-1930, Supplement 1, August 2011 (ADAMS Accession No. ML11242A215). These tube-to-tubesheet welds are exposed to reactor coolant and are fabricated with Alloy 600 type materials, which are susceptible to PWSCC. The following safety evaluation supplements Section 3.1.2.2.16(1) of NUREG-1930, Supplement 1.

As addressed in Section 3.1.2.2.16(1) of NUREG-1930, Supplement 1, the applicant committed to perform an analysis or a one-time inspection of the tube-to-tubesheet welds in each steam generator to address the potential for PWSCC (Commitment No. 42). In Option 1 (analysis option) of the commitment, the applicant will establish a technical basis to determine the resistance of these welds to PWSCC or to redefine the RCPB in which these welds are no longer part of RCPB. In Option 2 (inspection option) of the commitment, if the one-time inspection reveals PWSCC, the applicant will perform adequate repair or engineering evaluation to resolve the condition and will implement an ongoing monitoring program.

As previously addressed, the applicant submitted the information regarding its action on Commitment No. 42 by letter dated January 17, 2017 (ADAMS Accession No. ML17023A209). In the letter, the applicant indicated that Commitment No. 42 was closed by virtue of having satisfied Option 1 (analysis option) of that commitment in accordance with the new guidance in LR-ISG-2016-01. In its letter, the applicant also referred to the following guidance in LR-ISG-2016-01 that addresses aging management for tube-to-tubesheet welds:

- For units with Alloy 600 steam generator tubes and for which an alternate repair criterion such as C*, F*, W*, or H* has been permanently approved for both the hot- and cold-leg side of the steam generator, the weld is no longer part of the RCPB and a plant-specific AMP is not necessary.
- For units with thermally treated Alloy 690 steam generator tubes and with tubesheet cladding using Alloy 600 weld material, a plant-specific AMP is necessary unless the applicant confirms that the industry's analyses for tube-to-tubesheet weld cracking (e.g., chromium content for the tube-to-tubesheet welds is approximately 22 percent and the tubesheet cladding is in compression) are applicable and bounding for its unit, and the applicant will perform general visual inspections of the tubesheet region looking for evidence of cracking (e.g., rust stains on the tubesheet cladding) as part of the Steam Generator Program. In lieu of a plant-specific AMP, the applicant may provide a rationale for why a plant-specific AMP is not necessary.

The staff noted that the new guidance, which the applicant addressed, is also reflected in the updated acceptance criteria and review procedures of SRP-LR Sections 3.1.2.2.11.2 and 3.1.3.2.11.2, as revised in LR-ISG-2016-01. These updated SRP-LR sections provide guidance for further evaluation of PWSCC in steam generator tube-to-tubesheet welds.

The applicant's January 17, 2017, letter also clarifies that IP2 is a unit with Alloy 600 steam generator tubes for which alternate repair criterion H* has been permanently approved for both the hot- and cold-leg side of the steam generator, and is documented in TS Amendment 277 (September 5, 2014). Therefore, the tube-to-tubesheet welds are no longer part of the RCPB and a plant-specific AMP is not necessary for IP2 to manage cracking due to PWSCC in these components.

In its review, the staff finds that the applicant's determination (i.e., no need for a plant-specific AMP for IP2 tube-to-tubesheet welds) is acceptable because it is consistent with the guidance in LR-ISG-2016-01. In addition, the staff finds that potential PWSCC at the tube-to-tubesheet welds of IP2 steam generators would not affect the integrity of RCPB components, consistent with the staff-approved alternate repair criterion for the steam generators.

As previously discussed in SER Section 3.1.2.1, the applicant indicated that, in parallel with the staff's finalization of LR-ISG-2016-01, EPRI issued Information Letter SGMP-IL-16-02 on October 10, 2016, to inform licensees that EPRI Report 3002002850 and LR-ISG-2016-01 may be used as a basis to update AMPs and activities for steam generator head components made with materials susceptible to PWSCC. SGMP-IL-16-02 provides a checklist that reflects the bounding conditions considered in EPRI Report 3002002850 and other related EPRI technical reports in relation to tube-to-tubesheet welds. The checklist can be used to demonstrate that the industry analyses bound the conditions of the applicant's steam generators and tube-to-tubesheet welds.

In addition, the January 17, 2017, letter provides information related to tube-to-tubesheet welds in accordance with the EPRI checklist to confirm that the industry analyses are applicable and bounding for the conditions of the IP3 steam generators and their tube-to-tubesheet welds. In the submitted information related to tube-to-tubesheet welds, the applicant included materials of fabrication, material compositions, and tubesheet stress states as well as comparisons of these conditions with the bounding conditions analyzed in the industry analyses.

As discussed in Section 3.1.2.1, the staff found a concern about the loading condition evaluation of turbine-roll-test cycles. The staff issued RAI B.1.35-1 to determine, in part, whether the steam generator loading conditions of IP3 are bounded by those analyzed in EPRI Report 3002002850. In its review of the applicant's response dated May 19, 2017 (ADAMS Accession No. ML17145A288), the staff finds that the loading conditions of the IP3 steam generators are bounded by those analyzed in EPRI Report 3002002850, as previously discussed.

The staff also finds that the fabrication materials, material compositions, and other conditions such as fabrication processes for IP3 steam generator tubesheets are bounded by the conditions analyzed in EPRI Report 3002002850. Specifically, the applicant demonstrated that the conditions of IP3 steam generator tube-to-tubesheet welds are bounded by the material composition and stress state analyzed in the EPRI report (e.g., chromium content for the tube-to-tubesheet welds is approximately 22 percent and the tubesheet primary side is in compression). Therefore, the staff finds that the tube-to-tubesheet welds have resistance to potential initiation and propagation of PWSCC. Based on this review, the staff finds that a plant-specific program is not necessary to manage cracking due to PWSCC for the tube-to-tubesheet welds, consistent with the guidance in LR-ISG-2016-01.

As documented in SER Section 3.0.3.2.14, the applicant identified an enhancement to the Steam Generator Integrity Program. In the program enhancement, applicable procedures will be revised to specify general visual inspections of the steam generator channel heads, consistent with LR-ISG-2016-01. In addition, the staff's evaluation of the Water Chemistry Control – Primary and Secondary Program is documented in Section 3.0.3.2.16 of NUREG-1930, Volume 2 (November 2009).

In its review of the tube-to-tubesheet welds associated with LRA item 3.1.1-35, the staff finds that the applicant has met the further evaluation criteria (as revised in LR-ISG-2016-01), and the applicant's proposal to manage the effects of aging using the Steam Generator Integrity Program (with the enhancement) and Water Chemistry Control – Primary and Secondary Program acceptable because of the following: (1) the applicant confirmed that a plant-specific program is not necessary on the basis that an alternate repair criterion was approved for the IP2 steam generators and the conditions of the IP3 steam generators are bounded by those analyzed in EPRI Report 3002002850, consistent with LR-ISG-2016-01; (2) the Steam

Generator Integrity Program includes periodic visual inspections of channel head interior areas that can identify signs indicating cracking or loss of material in the channel heads and tubesheets; (3) these inspections can also confirm the integrity of RCPB components such as channel heads and tubesheets; and (4) the Water Chemistry Control – Primary and Secondary Program controls the levels of chemical species and contaminants within acceptable ranges to minimize environmental effects that can promote PWSCC.

As discussed above, the staff also finds that the applicant's determination regarding the completion of Commitment No. 42 (analysis option) is acceptable in accordance with the guidance in LR-ISG-2016-01. Based on the programs identified, the staff determines that the applicant's programs meet SRP-LR Section 3.1.2.2.11.2 criteria (as revised in LR-ISG-2016-01). For the steam generator tube-to-tubesheet welds associated with LRA Section 3.1.2.2.16(1), the staff concludes that the LRA (as amended in the letters dated January 17, 2017, and May 19, 2017) is consistent with the GALL Report (as revised in LR-ISG-2016-01) and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2 <u>Aging Management of Engineered Safety Features Systems</u>

3.2.2 Staff Evaluation

3.2.2.1 AMR Results Consistent with the GALL Report

By letter dated September 26, 2013 (ADAMS Accession No. ML13274A238), the applicant submitted an annual update to the LRA, identifying changes made to the CLB that materially affect the contents of the LRA. The applicant amended LRA tables associated with LRA Section 3.2 to add components associated with the black start diesel (GT3-BSD) at IP2 made of aluminum and copper alloy with greater than 15 percent zinc exposed to indoor air. However, by letter dated December 12, 2013 (ADAMS Accession No, ML13354B873), the applicant removed all of these items from the scope of license renewal because it re-evaluated the CLB and determined that it no longer relied on the black start diesel, and thus, all previously included components were removed from the scope of license renewal.

By letter dated December 12, 2013, the applicant amended LRA tables associated with LRA Section 3.2 to add components made of copper alloy with greater than 15 percent zinc exposed to indoor air. The AMR item cites generic note C.

By letter dated December 15, 2014 (ADAMS Accession No. ML14364A156), Entergy amended the LRA. The staff reviewed the information in this amendment and confirmed that the material presented in the amendment is applicable, and that the applicant identified the appropriate GALL Report AMRs.

The applicant amended LRA Table 3.3.2-19-8-IP2 by adding copper valve bodies exposed to indoor air with no AERM and no recommended AMP. The item cites SRP-LR Table 3.2-1, item 3.2.1-23, and generic note C. The staff reviewed the amendment to confirm that the applicant: (a) provided a brief description of the system, components, materials, and environments; (b) stated that the applicable aging effect was reviewed and evaluated in the GALL Report; and (c) identified the aging effect for the auxiliary system component that is subject to an AMR.

The staff reviewed the applicant’s revision noted above and found that the additional AMR result is consistent with the GALL Report for this combination of material and environment. On the basis of its review, the staff finds that the applicable aging effect was identified, and that the aging effect listed is appropriate for the combination of material and environment identified.

3.2.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation is Recommended

3.2.2.2.3 Loss of Material Due to Pitting and Crevice Corrosion

Item 5. LRA Section 3.2.2.2.3, associated with LRA Table 3.2.1 item 3.2.1-7, addresses partially encased stainless steel tanks with breached moisture barrier exposed to raw water that will be managed for loss of material due to pitting and crevice corrosion by the Aboveground Steel Tanks Program. The criteria in SRP-LR Revision 2, Section 3.2.2.2.3, item 1, state that loss of material due to pitting and crevice corrosion could occur for partially encased stainless steel tanks exposed to raw water due to cracking of the perimeter seal from weathering and recommends a plant-specific AMP to manage the effects of aging. The SRP-LR also states that the AMP acceptance criteria should ensure that the structure and component intended function(s) are maintained under all CLB design conditions during the period of extended operation, and that the AMP should include a methodology for analyzing the results against applicable acceptance criteria. The applicant addressed the further evaluation criteria of the SRP-LR by stating that “[i]nspections will be conducted in accordance with the Aboveground Steel Tanks Program to identify degradation of external surfaces of tank bottoms exposed to soil or concrete.”

The staff’s evaluation of the applicant’s Aboveground Steel Tanks Program is documented in Section 3.0.3.2.1. The staff noted that the applicant’s Aboveground Steel Tanks Program, as amended by letter dated December 16, 2014 (ADAMS Accession No. ML14365A069), states that the intended functions of storage tanks supported on soil or concrete foundations will be maintained during the period of extended operation by performing verification (e.g., thickness measurements) to ensure that significant degradation is not occurring in inaccessible locations, like the tank bottom. The staff also noted that the applicant’s Aboveground Steel Tanks Program includes provisions for performing volumetric inspections from the inside surface of stainless steel tanks mounted on concrete or soil during each 10-year period during the period of extended operation. In its review of components associated with item 3.2.1-7, the staff finds that the applicant has met the further evaluation criteria, and the applicant’s proposal to manage the effects of aging using the Aboveground Steel Tanks Program is acceptable because the program uses periodic volumetric inspections from tank internal surfaces that are capable of detecting degraded conditions of normally inaccessible exterior surfaces to ensure intended functions are maintained throughout the period of extended operation.

Based on the program identified, the staff finds that the applicant’s program meets SRP-LR Revision 2, Section 3.2.2.2.3, item 1 criteria. For those items associated with LRA Section 3.2.2.2.3 item 5, the staff concludes that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed such 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).

3.2A.2.3 IP2 AMR Results Not Consistent with or Not Addressed in the GALL Report

3.2A.2.3.2 Containment Spray System – Summary of Aging Management Review – LRA Table 3.2.2-2-IP2

Steel, Stainless Steel, and Copper Alloy Insulated Piping Components Exposed to Air-Outdoor and Condensation. As amended by letter dated December 16, 2014 (ADAMS Accession No. ML14365A069), LRA Tables 3.2.2-2-IP2, 3.2.2-4-IP2, 3.3.2-2-IP2, 3.3.2-7-IP2, 3.3.2-8-IP2, 3.3.2-10-IP2, 3.3.2-11-IP2, 3.3.2-14-IP2, 3.3.2-17-IP2, 3.3.2-19-1-IP2, 3.3.2-19-2-IP2, 3.3.2-19-7-IP2, 3.3.2-19-11-IP2, 3.3.2-19-13-IP2, 3.3.2-19-16-IP2, 3.3.2-19-17-IP2, 3.3.2-19-39-IP2, 3.3.2-19-43-IP2, 3.4.2-3-IP2, 3.4.2-5-4-IP2, 3.4.2-5-5-IP2, and 3.4.2-5-9-IP2 state that steel stainless steel, and copper-alloy insulated piping components exposed to air-outdoor (external) and condensation (external) will be managed for loss of material and cracking by the External Surfaces Monitoring Program. The AMR items cite generic note H; however, LR-ISG-2012-02 addresses CUI in SRP-LR items 3.2.1-69, 3.2.1-71, 3.3.1-132, and 3.4.1-63 using the External Surfaces Monitoring Program.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in Section 3.0.3.2.5. The staff finds the applicant's proposal to manage the effects of aging using the External Surfaces Monitoring Program acceptable because it is consistent with SRP-LR Table 3.2-1, AMR items 3.2.1-69, 3.2.1-71, 3.3.1-132, and 3.4.1-63, as amended by LR-ISG-2012-02.

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, as amended by letter dated December 16, 2014 (ADAMS Accession No. ML14365A069).

Stainless Steel Tanks Exposed to Outdoor Air. In LRA Table 3.2.2-4-IP2, the applicant stated that stainless steel tanks exposed to an external environment of outdoor air will be managed for loss of material by the Aboveground Steel Tanks Program instead of the External Surfaces Monitoring Program. The applicant cited note G to indicate that the environment for this component and material is not in the GALL Report, Revision 1.

The staff's evaluation of the applicant's Aboveground Steel Tanks Program is documented in Section 3.0.3.2.1. The staff finds the applicant's proposal to manage the effects of aging using the Aboveground Steel Tanks Program acceptable because it is consistent with SRP-LR AMR item 3.2.1-68, as amended by LR-ISG-2012-02.

Stainless Steel Tanks Exposed to Concrete. In LRA Table 3.2.2-4-IP2, the applicant stated that stainless steel tanks exposed to an external environment of concrete will be managed for loss of material by the Aboveground Steel Tanks Program. The applicant cited note H to indicate that the aging effect for this component, material, and environment is not in the GALL Report, Revision 1.

The staff's evaluation of the applicant's Aboveground Steel Tanks Program is documented in Section 3.0.3.2.1. The staff finds the applicant's proposal to manage the effects of aging using the Aboveground Steel Tanks Program acceptable because it is consistent with SRP-LR AMR item 3.2.1-68, as amended by LR-ISG-2012-02.

Stainless Steel Tanks Exposed to Treated Borated Water. In LRA Table 3.2.2-4-IP2, the applicant stated that stainless steel tanks exposed to an internal environment of treated borated water will be managed for loss of material by the Aboveground Steel Tanks Program. The applicant cited note E to indicate that for this component, material, and environment a different AMP than the one recommended in the GALL Report, Revision 1, is credited.

The staff's evaluation of the applicant's Aboveground Steel Tanks Program is documented in Section 3.0.3.2.1. The staff finds the applicant's proposal to manage the effects of aging using the Aboveground Steel Tanks program acceptable because it is consistent with SRP-LR AMR item 3.2.1-70, as amended by LR-ISG-2012-02.

3.2A.2.3.5 Containment Penetrations – Summary of Aging Management Review – LRA Table 3.2.2-5-IP2

Stainless Steel Exposed to Plant Indoor Air. By letter dated December 15, 2014 (ADAMS Accession No. ML14364A156), the applicant amended LRA Table 3.2.2-5-IP3 by adding stainless steel tubing and valves that are exposed internally to treated air. The AMR items cite generic note G. The applicant stated that there are no AERMs and no proposed AMP. The staff's evaluation of this material, environment, aging effect, and program combination is documented in SER Section 3.2A.2.3.5.

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

3.2B.2.3.2 Containment Spray System – Summary of Aging Management Review – LRA Table 3.2.2-2-IP3

Steel, Stainless Steel, and Copper-Alloy Insulated Piping Components Exposed to Air-Outdoor and Condensation. As amended by letter dated December 16, 2014 (ADAMS Accession No. ML14365A069), LRA Tables 3.2.2-2-IP3, 3.2.2-4-IP3, 3.3.2-2-IP3, 3.3.2-7-IP3, 3.3.2-8-IP3, 3.3.2-9-IP3, 3.3.2-10-IP3, 3.3.2-11-IP3, 3.3.2-14-IP3, 3.3.2-17-IP3, 3.3.2-19-13-IP3, 3.3.2-19-20-IP3, 3.3.2-19-56-IP3, 3.3.2-19-58-IP3, and 3.4.2-3-IP3 state that steel, stainless steel, and copper-alloy insulated piping components exposed to air-outdoor (external) and condensation (external) will be managed for loss of material and cracking by the External Surfaces Monitoring Program. The AMR items cite generic note H; however, LR-ISG-2012-02 addresses CUI in GALL Report items E-403, E-406, A-405, and S-402 using the External Surfaces Monitoring Program.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in Section 3.0.3.2.5. The staff finds the applicant's proposal to manage the effects of aging using the External Surfaces Monitoring Program acceptable because it is consistent with SRP-LR Table 3.2-1, AMR items 3.2.1-69, 3.2.1-71, and 3.3.1-132, as amended by LR-ISG-2012-02.

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, as amended by letter dated December 16, 2014 (ADAMS Accession No. ML14365A069).

Stainless Steel Tanks Exposed to Outdoor Air. In LRA Table 3.2.2-4-IP3, the applicant stated that stainless steel tanks exposed to an external environment of outdoor air will be managed for loss of material by the Aboveground Steel Tanks Program instead of the External Surfaces Monitoring Program. The applicant cited note G to indicate that the environment for this component and material is not in the GALL Report, Revision 1.

The staff's evaluation of the applicant's Aboveground Steel Tanks Program is documented in Section 3.0.3.2.1. The staff finds the applicant's proposal to manage the effects of aging using the Aboveground Steel Tanks Program acceptable because it is consistent with SRP-LR AMR item 3.2.1-68, as amended by LR-ISG-2012-02.

Stainless Steel Tanks Exposed to Concrete. In LRA Table 3.2.2-4-IP3, the applicant stated that stainless steel tanks exposed to an external environment of concrete will be managed for loss of material by the Aboveground Steel Tanks Program. The applicant cited note H to indicate that the aging effect for this component, material, and environment is not in the GALL Report, Revision 1.

The staff's evaluation of the applicant's Aboveground Steel Tanks Program is documented in Section 3.0.3.2.1 above. The staff finds the applicant's proposal to manage the effects of aging using the Aboveground Steel Tanks Program acceptable because it is consistent with SRP-LR AMR item 3.2.1-68, as amended by LR-ISG-2012-02.

Stainless Steel Tanks Exposed to Treated Borated Water. In LRA Table 3.2.2-4-IP3, the applicant stated that stainless steel tanks exposed to an internal environment of treated borated water will be managed for loss of material by the Aboveground Steel Tanks Program. The applicant cited note E to indicate that for this component, material, and environment a different AMP than the one recommended in the GALL Report, Revision 1, is credited.

The staff's evaluation of the applicant's Aboveground Steel Tanks Program is documented in Section 3.0.3.2.1. The staff finds the applicant's proposal to manage the effects of aging using the Aboveground Steel Tanks Program acceptable because it is consistent with SRP-LR AMR item 3.2.1-70, as amended by LR-ISG-2012-02.

3.2.2.4 Conclusion

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 consistent with, or 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).

3.3 <u>Aging Management of Auxiliary Systems</u>

3.3.2 Staff Evaluation

3.3.2.1 AMR Results Consistent with the GALL Report

By letter dated September 26, 2013 (ADAMS Accession No. ML13274A238), the applicant submitted an annual update to the LRA, identifying changes made to the CLB that materially affect the contents of the LRA. The applicant amended LRA tables associated with LRA Section 3.3 to add components associated with the black start diesel (GT3-BSD) at IP2 made of carbon steel, stainless steel, copper alloy with greater than 15 percent zinc, and gray cast iron exposed to indoor air, fuel oil, and treated water. However, by letter dated December 12, 2013, the applicant removed these items from the scope of license renewal because it re-evaluated the CLB and determined that it no longer relied on the black start diesel, and thus, all previously included components were removed from the scope of license renewal.

By letter dated December 15, 2014 (ADAMS Accession No. ML14364A156), the applicant amended LRA Tables 3.3.2-2-IP3 and 3.4.2-5-9-IP2 by adding stainless steel and gray cast iron flexible hoses and valve bodies exposed to raw water and condensation that are being managed for loss of material by the Service Water Integrity, External Surfaces Monitoring, and Selective Leaching Programs. The items cite SRP-LR Table 3.3-1, items 3.3.1-58, 3.3.3.1-76, 3.3.1-79, 3.3.1-85, and generic note A. The staff reviewed the amendment 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.

The staff reviewed the applicant's revision noted above and found that the additional AMR result is consistent with the GALL Report for this combination of material and environment. On the basis of its review, the staff finds that all applicable aging effects were identified and that the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.2.1.2 Loss of Material Due to General Corrosion

By letter dated December 16, 2014 (ADAMS Accession No. ML14365A069), LRA Table 3.3.1, item 58 addresses loss of material due to general corrosion on steel external surfaces exposed to air-indoor uncontrolled (external), air-outdoor (external), and condensation (external). The GALL Report recommends the External Surfaces Monitoring Program to manage this aging effect. As amended by letter dated December 16, 2014, the applicant revised LRA Tables 3.3.2-11-IP2 and 3.3.2-11-IP3 to state that the fire water storage tanks exposed to air-indoor (external), air-outdoor (external), and condensation (external) will be managed by the Fire Water System Program. The applicant cited generic note E. However, the staff noted that LR-ISG-2012-02 recommends that aging effects associated with the fire water storage tanks be managed by the Fire Water System Program. The staff finds the applicant's use of the Fire Water System Program to manage loss of material for the fire water storage tanks acceptable because it is consistent with LR-ISG-2012-02 item VII.G.A-412.

3.3.2.1.14 Loss of Material Due to Pitting and Crevice Corrosion

By letter dated December 15, 2014 (ADAMS Accession No. ML14364A156), the applicant amended LRA Table 3.4.2-5-9-IP2 by adding stainless steel flex hoses which are exposed to condensation (external) and will be managed for loss of material. The AMR item, which cites SRP-LR Table 3.3-1, item 3.3.1-27 and generic note E, credits the External Surfaces Monitoring Program to manage loss of material. The staff's evaluation of loss of material for stainless steel piping and piping components exposed to condensation being managed by the External Surfaces Monitoring Program is documented in SER Section 3.3.2.2.10(5).

3.3.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation is Recommended

3.3.2.2.9 Loss of Material Due to General, Pitting, Crevice, MIC, and Fouling

As amended by letter dated December 27, 2012 (ADAMS Accession No. ML13003A178), LRA Tables 3.3.2-19-13-IP3 and 3.4.2-5-4-IP2 state that copper-alloy flow elements and tubing, and gray cast iron valve bodies exposed internally to treated water, will be managed for loss of material by the Periodic Surveillance and Preventive Maintenance Program. The AMR item cites generic note G. The AMR item cites plant-specific note 305, which states that this treated water environment includes water that has been treated but is not maintained by a Chemistry Control Program.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noted that the applicant addressed selective leaching for the gray cast iron valve bodies exposed to treated water in another AMR item in LRA Table 3.3.2-5-4-IP2. Given that the water is treated, but not maintained by a Chemistry Control Program, the staff evaluated these items as if they were exposed to raw water. GALL Report items AP-45 and SP-31 (GALL Report, Revision 2) state that loss of material due to pitting and crevice corrosion, MIC, and fouling are the only applicable aging effects. Given that the water is treated before being added to the system, fouling is not expected to occur (reference GALL Report item AP-64 of the GALL Report, Revision 2) for copper alloy exposed to treated water. The staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.3.7. The staff finds the applicant's proposal to manage aging using the Periodic Surveillance and Preventive Maintenance Program acceptable because the program uses periodic visual inspection of a representative sample to confirm the effectiveness of managing aging effects. These visual inspections are capable of detecting pitting and crevice corrosion, and MIC.

3.3A.2.3 IP2 AMR Results Not Consistent with or Not Addressed in the GALL Report

3.3A.2.3.1 Service Water System Summary of Aging Management Review – LRA Table 3.3.2-2-IP2

Carbon Steel and Stainless Steel Piping, Piping Components, Heat Exchanger Components, and Tanks Exposed to Treated Water, Raw Water, Lubricating Oil, and Fuel Oil. As amended by letters dated March 10, 2015 (ADAMS Accession No. ML15075A022), and September 1, 2015 (ADAMS Accession No. ML15251A237), LRA Tables 3.3.2-2[-IP2, -IP3], 3.3.2-3[-IP2, -IP3], 3.3.2-10-IP3, 3.3.2-11[-IP2, -IP3], 3.3.2-13[-IP2, -IP3], 3.3.2-14-IP2, 3.3.2-17[-IP2, -IP3], 3.3.2-19-2-IP2, 3.3.2-19-7-IP2, 3.3.2-19-11-IP2, 3.3.2-19-13-IP2, 3.3.2-19-30-IP2, 3.3.2-19-39-IP2, 3.3.2-19-12-IP3, 3.3.2-19-13-IP3, 3.3.2-19-20-IP3, 3.3.2-19-31-IP3, 3.3.2-19-43-IP3, 3.3.2-19-54-IP3, 3.3.2-19-56-IP3, and 3.3.2-19-58-IP3 state that internally coated metal piping, heat exchanger components, and tanks exposed to treated water, raw water, lubricating oil, and fuel oil will be managed for loss of coating integrity by the Coating Integrity Program. The AMR items cite generic note H.

The staff noted that although the applicant cited generic note H; LR-ISG-2013-01, "Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," provides AMR items to address this material, environment, aging effect, and AMP combination. SRP-LR Table 3.3-1, item 3.3.1 138, states that metallic piping, piping components, heat exchangers, and tanks with internal coatings/linings exposed to raw water, treated water, lubricating oil, or fuel oil are managed for loss of coating integrity by AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks."

The staff's evaluation of the applicant's Coating Integrity Program is documented in SER Section 3.0.3.3.11. The staff finds the applicant's proposal to manage the effects of aging using the Coating Integrity Program acceptable because periodic visual inspections of internal coatings by qualified personnel are capable of detecting loss of coating integrity.

<u>Nickel Alloy Rupture Disc Exposed Externally to Condensation</u>. By letter dated December 14, 2017 (ADAMS Accession No. ML17360A157), the applicant amended LRA Table 3.3.2-2-IP2 by stating that nickel alloy rupture discs exposed externally to condensation will be managed for loss of material with the External Surface Monitoring Program. The AMR item cites generic note G. The staff's evaluation of the External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.5. The staff noted that for nickel alloy components exposed to condensation: (a) NUREG-2191, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report," item AP-221b recommends that AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," be used to manage loss of material due to general, pitting, and crevice corrosion; and (b) no other aging effects were identified in NUREG-2191 for this material and environment combination. The staff finds the applicant's proposal to manage loss of material for nickel alloy piping components exposed to condensation with the External Surfaces Monitoring Program is consistent with the GALL Report and the visual examinations conducted for the applicant's program are capable of detecting loss of material.

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, as amended by letter dated December 16, 2014 (ADAMS Accession No. ML14365A069).

<u>Insulated Stainless Steel Tanks Exposed to Outdoor Air</u>. In LRA Table 3.3.2-7-IP2, the applicant stated that insulated stainless steel tanks exposed to an external environment of outdoor air will be managed for loss of material and cracking by the Aboveground Steel Tanks Program. The applicant cited note H to indicate that the aging effect for this component, material, and environment is not in the GALL Report, Revision 1. The applicant also cited plant-specific note 320 that states "[p]rogram provisions apply for indoor insulated components that operate below the dew point and outdoor insulated components."

The staff's evaluation of the applicant's Aboveground Steel Tanks Program is documented in Section 3.0.3.2.1. The staff finds the applicant's proposal to manage the effects of aging using the Aboveground Steel Tanks Program acceptable because the items are consistent with SRP-LR AMR item 3.3.1-132 (loss of material and cracking), as amended by LR-ISG-2012-02.

Stainless Steel Tanks Exposed to Outdoor Air. In LRA Table 3.3.2-7-IP2, the applicant stated that stainless steel tanks exposed to an external environment of outdoor air will be managed for loss of material by the External Surfaces Monitoring Program. The applicant cited note G to indicate that the environment for this component and material is not in the GALL Report, Revision 1. By letter dated December 16, 2014, this AMR item was deleted from the table.

Stainless Steel Tanks Exposed to Concrete. In LRA Table 3.3.2-7-IP2, the applicant stated that stainless steel tanks exposed to an external environment of concrete will be managed for loss of material by the Aboveground Steel Tanks Program. The applicant cited note H to indicate that the aging effect for this component, material, and environment is not in the GALL Report, Revision 1.

The staff's evaluation of the applicant's Aboveground Steel Tanks Program is documented in Section 3.0.3.2.1. The staff finds the applicant's proposal to manage the effects of aging using the Aboveground Steel Tanks Program acceptable because it is consistent with SRP-LR AMR item 3.3.1-128, as amended by LR-ISG-2012-02.

Stainless Steel Tanks Exposed to Treated Water. In LRA Table 3.3.2-7-IP2, the applicant stated that stainless steel tanks exposed to an internal environment of treated water will be managed for loss of material by the Aboveground Steel Tanks Program. The applicant cited note E to indicate that for this component, material, and environment a different AMP than the one recommended in GALL Report, Revision 1, is credited.

The staff's evaluation of the applicant's Aboveground Steel Tanks Program is documented in Section 3.0.3.2.1. The staff finds the applicant's proposal to manage the effects of aging using the Aboveground Steel Tanks program acceptable because it is consistent with SRP-LR AMR item 3.3.1-137, as amended by LR-ISG-2012-02.

3.3A.2.3.8 Fire Protection – Water System – Summary of Aging Management Review – LRA Table 3.3.2-11-IP2

Metal Tanks with Internal Coating Exposed to Treated Water. As amended by letter dated March 10, 2015 (ADAMS Accession No. ML15075A022), LRA Tables 3.3.2-11-IP2 and 3.3.2-11-IP3 state that metal tanks (in the fire protection – water system) with internal coatings exposed to treated water will be managed for loss of coating integrity by the Fire Water System Program. The AMR items cite generic note H.

The staff noted that although the applicant cited generic note H, LR-ISG-2013-01, "Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," GALL Report item VII.G.A-416 cites AMP XI.M42 for internal coatings on fire water system components. AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," states that "[t]he aging effects associated with fire water tank internal coatings/linings are managed by GALL Report AMP XI.M27, 'Fire Water System,' instead of this AMP."

The staff's evaluation of the applicant's Fire Water System Program, as modified to address LR-ISG-2013-01, is documented in SER Section 3.0.3.4.3. The staff finds the applicant's proposal to manage the effects of aging using the Fire Water System Program acceptable because periodic visual inspections of internal coatings by qualified personnel are capable of detecting loss of coating integrity.

3.3A.2.3.14 City Water System -Summary of Aging Management Review – LRA Table 3.3.2-17-IP2

Steel Tanks Exposed to Treated Water. As amended by letter dated December 16, 2014 (ADAMS Accession No. ML14365A069), LRA Table 3.3.2-17-IP2 states that steel tanks exposed to an internal environment of treated water will be managed for loss of material by the Aboveground Steel Tanks Program. The applicant cited note G and plant-specific note 305. Plant-specific 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 staff noted that under the Aboveground Steel Tanks Program, components exposed to treated water, as defined in the GALL Report, are subject to a one-time inspection, whereas components exposed to raw water are subject to periodic inspections. By letter dated August 18, 2015, the applicant revised the inspection details tables of the Aboveground Steel Tanks Program in LRA Sections A.2.1.1 and B.1.1 to require periodic inspections for steel tanks exposed to raw water, specifically for the city water tank.

The staff's evaluation of the applicant's Aboveground Steel Tanks Program is documented in Section 3.0.3.2.1. The staff finds the applicant's proposal to manage the effects of aging using the Aboveground Steel Tanks Program acceptable because the periodic inspection requirement for the city water tank will be consistent with SRP-LR AMR item 3.3.1-129, as amended by LR-ISG-2012-02.

3.3A.2.3.15 Plant Drains-Summary of Aging Management Review –LRA Table 3.3-2-18-IP2

PVC piping exposed to soil. As amended by letter dated June 30, 2009 (ADAMS Accession No. ML091880426), LRA Table 3.3.2-18-IP2 stated that for PVC piping exposed to soil there is no aging effect and no AMP is proposed. The AMR item cites generic note F.

The staff's evaluation of the adequacy of no aging effect for PVC piping exposed to soil is documented in NUREG-1930, Section 3.3A.2.3.15; however, with the issuance of LR-ISG-2015-01, the staff revised the "detection of aging effects" program element of GALL Report AMP XI.M41 to recommend visual inspections of the external surface condition of polymeric materials to detect loss of material due to wear. By letter dated June 27, 2017 (ADAMS Accession No. ML17170A286), the staff issued RAI 3.0.2.1.2-2 requesting that the applicant state the basis for why loss of material due to wear is not an AERM for PVC piping exposed to soil. The staff's evaluation of the applicant's response to RAI 3.0.2.1.2-2 is documented in SER Section 3.0.3.1.2.

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

Metal with Internal Coating Internally Exposed to Steam. By letter dated February 26, 2018 (ADAMS Accession No. ML18064A136), the applicant amended LRA Table 3.3.2-19-4-IP2 by stating that metal piping with internal aluminide coating exposed to steam will be managed for loss of material by the Flow-Accelerated Corrosion Program. The AMR item cites generic note F. In its letter, the applicant stated: (a) new elbows were installed in the steam jet air ejector exhausts to the condenser, (b) the elbows would normally be at a vacuum, (c) the internal coating consists of a vapor-phase aluminide coating applied to the inside surface, and

(d) the coating is 0.003-0.005 inches thick and is diffused into the parent alloy through a gas vapor application method.

The staff noted that AMP XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks,” recommends that loss of coating integrity be managed for internally coated piping components to provide reasonable assurance that: (a) loss of material, and (b) downstream flow blockage will not affect the intended function of the component. The staff also noted that AMP XI.M42 allows the use of wall thickness measurements in lieu of internal visual inspections of the coating where loss of coating integrity will not result in downstream flow blockage. The staff’s evaluation of the Flow-Accelerated Corrosion Program is documented in SER Section 3.0.3.1.5. The staff finds the applicant’s proposal acceptable because (a) given that the elbows exhaust to the condenser downstream of the air ejector nozzles, the method of applying the coating (diffusion into the parent alloy), and thickness of the coating, there is reasonable assurance that downstream flow blockage will not occur; (b) the periodic volumetric inspections conducted by the Flow-Accelerated Corrosion Program are capable of detecting loss of material; and (c) managing loss of material in lieu of loss of coating integrity can be adequate to ensure that unanticipated through-wall corrosion will not occur.

3.3A.2.3.35 Primary Makeup Water System – Summary of Aging Management Review – LRA Table 3.3.2-19-43-IP2

Carbon Steel Tanks Exposed to Outdoor Air. As amended by letter dated December 16, 2014 (ADAMS Accession No. ML14365A069), LRA Table 3.3.2-19-43-IP2 states that insulated carbon steel tanks exposed to an external environment of outdoor air will be managed for loss of material by the Aboveground Steel Tanks Program. The applicant cited note H to indicate that the aging effect for this component, material, and environment is not in the GALL Report, Revision 1. The applicant also cited plant-specific note 320, which states “[p]rogram provisions apply for indoor insulated components that operate below the dew point and outdoor insulated components.”

The staff’s evaluation of the applicant’s Aboveground Steel Tanks Program is documented in Section 3.0.3.2.1. The staff finds the applicant’s proposal to manage the effects of aging using the Aboveground Steel Tanks Program acceptable because the item is consistent with SRP-LR AMR item 3.3.1-132, as amended by LR-ISG-2012-02.

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

Plastic Piping and Valve Body Exposed Externally to Outdoor Air. By letter dated December 15, 2016 (ADAMS Accession No. ML16358A526), the applicant amended LRA Table 3.3.2-19-44-IP2 by adding plastic piping that is exposed externally to indoor air. This AMR item states that there is no AERM for this material and environment combination. The staff noted that the applicant did not provide sufficient information on the specific type of plastic and on the indoor air and treated water environments to evaluate whether the appropriate aging effects have been identified. By letter dated April 28, 2017 (ADAMS Accession No. ML17142A271), the staff issued RAI 3.3.2-19-44-IP2-1 to request that the applicant state: (1) the specific type of plastic material, (2) the degree to which the external surface of the piping and valve body might be exposed to environmental factors, (3) the type of chlorine the piping and valve will be exposed to, and (4) the basis for not managing any effects if the above environmental factors are applicable.

By letter dated June 8, 2017 (ADAMS Accession No. ML17166A380), the applicant responded to RAI 3.3.2-19-44-IP2-1, stating that the specific type of plastic is chlorinated polyvinyl chloride (CPVC). The applicant revised the indoor air environment to outdoor air. The staff reviewed the following websites on June 20, 2017, to identify the impact of potential environmental factors that could result in age-related degradation for CPVC:

- *Chemical Resistance and Chemical Applications for CPVC Pipe and Fittings:* http://www.chemicalprocessing.com/assets/wp_ downloads/pdf/ChemicalResistanceWhitePaperFINAL.pdf (ADAMS Accession No. ML18207A604)
- *The Effects of Sunlight Exposure on PVC Pipe and Conduit:* http://www.jmeagle.com/sites/default/files/TB10SunlightEffectsonPVC 0.pdf (ADAMS Accession No. ML18207A448)
- *Ozone Compatible Materials:* http://www.ozonesolutions.com/info/ozone-compatible-materials (ADAMS Accession No. ML18207A768)

These websites state that the environmental factors affect CPVC similarly to PVC, except that CPVC has higher temperature resistance.

The applicant stated that most of the CPVC piping is installed below floor grating or along walls of the intake structure, which shields it from significant sources of ultraviolet light. The applicant further stated that some sections of the piping are exposed to sunlight at times during the day. As a result, the applicant amended its LRA to include change in material properties that will be managed by the External Surfaces Monitoring Program. The staff noted that the websites state that CPVC piping exposed to sunlight can result in discoloration and decreased impact strength. The staff finds the applicant proposal to manage change in material properties using the External Surfaces Monitoring Program acceptable because the applicant's program uses periodic inspections that are capable of detecting discoloration in polymers. The staff's evaluation of the External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.5.

In its response, the applicant also stated that the CPVC piping is exposed to a solution of 15 percent commercial grade sodium hypochlorite (i.e., treated water) and that there are no AERMs due to chemicals. The staff noted that the websites state that sodium hypochlorite will not degrade CPVC piping, even in high-temperature environments and that the recommended maximum temperature of CPVC piping exposed to sodium hypochlorite is 200 °F. Therefore, the staff finds the applicant's basis acceptable.

In its response, the applicant also stated that the CPVC piping is designed for 100 °F and that the outside design temperature is 93 °F dry bulb. Based on website information pertaining to maximum recommended temperature for CPVC piping, the staff finds the applicant's basis that there are no AERMs due to elevated temperatures acceptable.

In its response, the applicant also stated that CPVC piping is not affected by ozone. The staff noted that the websites confirmed that ozone has no effect on CPVC, therefore, the staff finds the applicant's basis acceptable.

In its response, the applicant states that the CPVC is not exposed to a radiation source that could contribute to AERMs. The staff finds it reasonable that the piping's location within the Chlorination System Intake Building is not a significant source of radiation, and therefore finds the applicant's basis acceptable.

Based on the reasons above, the staff finds the applicant's response to RAI 3.3.2-19-44-IP2-1 acceptable. On the basis of its review, the staff concludes that (for this item in LRA Table 3.3.2-19-44-IP2) the applicant has demonstrated that the effects of aging will be adequately managed so that its intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Plastic Piping and Valve Body Exposed Internally to Treated Water</u>. By letter dated December 15, 2016 (ADAMS Accession No. ML16358A526), the applicant amended LRA Table 3.3.2-19-44-IP2 by adding plastic piping that is exposed internally to treated water. This AMR item states that there is no AERM for this material and environment combination. The staff reviewed *Chemical Resistance and Chemical Applications for CPVC Pipe and Fittings,* <u>http://www.chemicalprocessing.com/assets/wp_downloads/pdf/ChemicalResistanceWhitePaperFINAL.pdf</u> on June 20, 2017, which states that environmental factors affect CPVC similarly to PVC, except that CPVC has higher temperature resistance. The staff's evaluation for PVC piping exposed internally to treated water, which has no AERM, is documented in SER Section 3.3B.2.3.19.

3.3B.2.3 IP3 AMR Results Not Consistent with or Not Addressed in the GALL Report

3.3B.2.3.1 Service Water System – Summary of Aging Management Review – LRA Table 3.3.2-2-IP3

<u>Carbon Fiber Reinforced Epoxy Piping Externally Exposed to Air-Indoor</u>. By letter dated December 14, 2017 (ADAMS Accession No. ML17360A158), the applicant amended LRA Table 3.3.2-2-IP3 by stating that carbon fiber reinforced epoxy piping externally exposed to indoor air will be managed for cracking, blistering, and loss of material by the Periodic Surveillance and Preventive Maintenance Program. The AMR item cites generic note F.

The staff reviewed the associated item in the LRA and considered whether the aging effects that the applicant proposed constitute all of the credible aging effects for this component, material, and environment combination. The staff notes that the applicant will visually inspect the surface of the epoxy overlay material each operating cycle. The staff also notes that the aging effects associated with epoxy matrix material would be consistent with the aging effects for other polymeric materials such as those used for coatings in buried or underground piping. Based on its review of the staff's latest guidance for buried piping in LR-ISG-2015-01, "Changes to Buried and Underground Piping and Tank Recommendations," the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.3.7. The staff finds the applicant's proposal to manage the effects of aging using this program acceptable because visual inspections are capable of detecting any age-related degradation of the carbon fiber reinforced epoxy piping.

<u>Nickel Alloy Rupture Disc Exposed Externally to Condensation</u>. By letter dated December 14, 2017 (ADAMS Accession No. ML17360A157), the applicant amended LRA

Table 3.3.2-2-IP3 by stating that nickel alloy rupture disc exposed externally to condensation will be managed for loss of material with the External Surfaces Monitoring Program. The AMR item cites generic note G. The staff's evaluation of the External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.5. The staff noted that for nickel alloy components exposed to condensation: (a) NUREG-2191, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report," item AP-221b recommends that AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," be used to manage loss of material due to general, pitting, and crevice corrosion; and (b) no other aging effects were identified in NUREG-2191 for this material and environment combination. The staff finds the applicant's proposal to manage loss of material for nickel alloy piping components exposed to condensation with the External Surfaces Monitoring Program is consistent with the GALL-SLR Report and the visual examinations conducted for the applicant's program are capable of detecting loss of material.

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, as amended by letter dated December 16, 2014 (ADAMS Accession No. ML14365A069).

Insulated Stainless Steel Tanks Exposed to Outdoor Air. In LRA Table 3.3.2-7-IP3, the applicant stated that insulated stainless steel tanks exposed to an external environment of outdoor air will be managed for loss of material and cracking by the Aboveground Steel Tanks Program. The applicant cited note H to indicate that the aging effect for this component, material, and environment is not in the GALL Report, Revision 1. The applicant also cited plant-specific note 320 that states "[p]rogram provisions apply for indoor insulated components that operate below the dew point and outdoor insulated components."

The staff's evaluation of the applicant's Aboveground Steel Tanks Program is documented in Section 3.0.3.2.1. The staff finds the applicant's proposal to manage the effects of aging using the Aboveground Steel Tanks Program acceptable because the items are consistent with SRP-LR AMR item 3.3.1-132 (loss of material and cracking), as amended by LR-ISG-2012-02.

Stainless Steel Tanks Exposed to Outdoor Air. In LRA Table 3.3.2-7-IP3, the applicant stated that stainless steel tanks exposed to an external environment of outdoor air will be managed for loss of material by the External Surfaces Monitoring Program. The applicant cited note G to indicate that the environment for this component and material is not in the GALL Report, Revision 1. By letter dated December 16, 2014, this AMR item was deleted from the table.

Stainless Steel Tanks Exposed to Concrete. In LRA Table 3.3.2-7-IP3, the applicant stated that stainless steel tanks exposed to an external environment of concrete will be managed for loss of material by the Aboveground Steel Tanks Program. The applicant cited note H to indicate that the aging effect for this component, material, and environment is not in the GALL Report, Revision 1.

The staff's evaluation of the applicant's Aboveground Steel Tanks Program is documented in Section 3.0.3.2.1. The staff finds the applicant's proposal to manage the effects of aging using the Aboveground Steel Tanks Program acceptable because it is consistent with SRP-LR AMR item 3.3.1-128, as amended by LR-ISG-2012-02.

Stainless Steel Tanks Exposed to Treated Water. In LRA Table 3.3.2-7-IP3, the applicant stated that stainless steel tanks exposed to an internal environment of treated water will be managed for loss of material by the Aboveground Steel Tanks Program. The applicant cited note E to indicate that for this component, material, and environment a different AMP than the one recommended in GALL Report, Revision 1, is credited.

The staff's evaluation of the applicant's Aboveground Steel Tanks Program is documented in Section 3.0.3.2.1. The staff finds the applicant's proposal to manage the effects of aging using the Aboveground Steel Tanks Program acceptable because it is consistent with SRP-LR AMR item 3.3.1-137, as amended by LR-ISG-2012-02.

3.3B.2.3.13 IP3 City Water-Summary of Aging Management Review – LRA Table 3.3.2-17-IP3

Fiberglass Piping Exposed to Soil. As amended by letter dated December 15, 2016 (ADAMS Accession No. ML16358A526), LRA Table 3.3.2-17-IP3 states that for fiberglass piping exposed to soil there is no aging effect and no AMP is proposed. The AMR item cites generic note F.

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material, and environmental combination. During its review the staff noted: (a) it was unclear, based on conflicting information provided in the letter dated December 15, 2016, if the item represented in LRA Table 3.3.2-17-IP3 is fiberglass piping or carbon fiber applied on the exterior circumference of the pipe; and (b) the "parameters monitored or inspected" program element of GALL Report AMP XI.M41, "Buried and Underground Piping and Tanks," as modified by LR-ISG-2015-01, recommends visual inspections of the external surface condition of polymeric materials to detect loss of material due to wear; and cracking, blistering, and change in color due to water absorption. By letter dated April 28, 2017 (ADAMS Accession No. ML17110A133), the staff issued RAI 3.3.2-17-IP3-1 requesting that the applicant: (a) clarify if the item represented in LRA Table 3.3.2-17-IP3 is fiberglass piping or is carbon fiber applied on the exterior circumference of the pipe; and (b) state the basis for why loss of material due to wear; and cracking, blistering, and change in color due to water absorption are not AERMs for polymeric materials exposed to soil.

In its response dated June 8, 2017 (ADAMS Accession No. ML17166A380), the applicant stated that the subject material is carbon fiber reinforced epoxy; however, during its review the staff noted an inconsistency between the applicant's response and the revised LRA Table 3.3.2-17-IP3. The staff noted that the applicant's response states that the carbon fiber reinforced epoxy is applied on the exterior circumference of a pressure-retaining clamp; however, the revised LRA Table 3.3.2-17-IP3 states that the piping is made of carbon fiber reinforced epoxy. The staff requested that the applicant supplement the June 8, 2017, letter to address this inconsistency.

In its supplemental response dated July 27, 2017 (ADAMS Accession No. ML17216A031), the applicant: (a) stated that the carbon fiber reinforced epoxy is applied on the exterior circumference of a carbon steel pressure-retaining clamp; and (b) deleted the subject item from LRA Table 3.3.2-17-IP3 on the basis that the carbon steel, not the carbon fiber reinforced epoxy, acts as the pressure boundary and is already accounted for in LRA Table 3.3.2-17-IP3.

The staff finds the applicant's response acceptable because the carbon steel acts as the piping pressure boundary and the carbon fiber reinforced epoxy acts as a coating; therefore, because carbon steel piping exposed to soil is already captured in LRA Table 3.3.2-17-IP3, the AMR item associated with carbon fiber reinforced epoxy is no longer applicable. The staff's concern described in RAI 3.3.2-17-IP3-1 is resolved.

3.3B.2.3.14 Plant Drains – Summary of Aging Management Review – LRA Table 3.3.2-18-IP3

PVC Piping Exposed to Soil. As amended by letter dated June 30, 2009 (ADAMS Accession No. ML091880426), LRA Table 3.3.2-18-IP3 stated that for PVC piping exposed to soil there is no aging effect and no AMP is proposed. The AMR item cites generic note F.

The staff's evaluation of the adequacy of no aging effect for PVC piping exposed to soil is documented in NUREG-1930, Section 3.3B.2.3.14; however, with the issuance of LR-ISG-2015-01, the staff revised the "detection of aging effects" program element of GALL Report AMP XI.M41 to recommend visual inspections of the external surface condition of polymeric materials to detect loss of material due to wear. By letter dated June 27, 2017 (ADAMS Accession No. ML17170A286), the staff issued RAI 3.0.3.1.2-2 requesting that the applicant state the basis for why loss of material due to wear is not an AERM for PVC piping exposed to soil. The staff's evaluation of the applicant's response to RAI 3.0.3.1.2-2 is documented in SER Section 3.0.3.1.2.

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

As amended by letter dated December 27, 2012 (ADAMS Accession No. ML13003A178), LRA Tables 3.3.2-19-13-IP3 and 3.4.2-5-4-IP2 state that copper-alloy flow elements and tubing, and gray cast iron valve bodies exposed internally to treated water will be managed for loss of material by the Periodic Surveillance and Preventive Maintenance Program. The AMR item cites generic note G. The AMR item cites plant-specific note 305, which states that this treated water environment includes water that has been treated but is not maintained by a Chemistry Control Program.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noted that the applicant addressed selective leaching for the gray cast iron valve bodies exposed to treated water in another AMR item in LRA Table 3.3.2-5-4-IP2. Given that the water is treated, but not maintained by a Chemistry Control Program, the staff evaluated these items as if they were exposed to raw water. GALL Report items AP-45 and SP-31 (GALL Report, Revision 2) state that loss of material due to pitting and crevice corrosion, MIC, and fouling are the only applicable aging effect. Given that the water is treated before being added to the system, fouling is not expected to occur (reference GALL Report item AP-64 of the GALL Report, Revision 2, for copper alloy exposed to treated water. The staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.3.7. The staff finds the applicant's proposal to manage aging using the Periodic Surveillance and Preventive Maintenance Program acceptable because the program uses periodic visual inspection of a representative sample to confirm the effectiveness of managing aging effects. These visual inspections are capable of detecting pitting and crevice corrosion, and MIC.

By letter dated December 12, 2013 (ADAMS Accession No. ML13354B873), the applicant amended LRA Table 3.3.2-19-13-IP3 by adding copper alloy with greater than 15 percent zinc strainer housings exposed internally to treated water. The components will be managed for loss of material with the Periodic Surveillance and Preventive Maintenance Program. The AMR item cites generic note G. The staff's evaluation of this material, environment, aging effect, and program combination is documented in NUREG-1930 Section 3.3A.2.3.14.

3.3B.2.3.42 Fuel Oil Systems – Summary of Aging Management Review – LRA Table 3.3.2-13-IP2

By letter dated December 27, 2012 (ADAMS Accession No. ML13003A178), the applicant mistakenly amended LRA Table 3.3.2-13-IP3 (instead of LRA Table 3.3.2-13-IP2) by adding components citing various material, environment, aging effects, and AMPs. By letter dated September 26, 2013 (ADAMS Accession No. ML13274A238), the applicant amended LRA Table 3.3.2-13-IP2 to add the above components, but neglected to delete them from LRA Table 3.3.2-13-IP3. By letter dated December 14, 2017 (ADAMS Accession No. ML17360A157), the applicant corrected this oversight from the December 27, 2012, letter by deleting these components from LRA Table 3.3.2-13-IP3. The staff's evaluation of the scoping and screening of components in the fuel oil systems is documented in SER Section 2.3A.3.13.

3.3.2.4 Conclusion

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of combinations of material, environment, AERMs, and AMPs not consistent with, or 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).

3.4 <u>Aging Management of Steam and Power Conversion Systems</u>

3.4.2 Staff Evaluation

3.4.2.1 AMR Results Consistent with the GALL Report

3.4.2.1.8 Stainless Steel and Copper Alloy Piping, Piping Components, and Piping Elements Exposed to Raw Water

By letter dated December 15, 2014 (ADAMS Accession No. ML14364A156), the applicant amended LRA Table 3.3.2-19-8-IP2 by adding copper-alloy valve bodies that are exposed to raw water (internal) and that will be managed for loss of material. The AMR item, which cites item 3.4.1-32 and generic note E, credits the Periodic Surveillance and Preventive Maintenance Program. The staff's evaluation of loss of material for copper-alloy piping and piping components exposed to raw water being managed by the Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.4.2.1.8

3.4A.2.3 IP2 AMR Results Not Consistent with or Not Addressed in the GALL Report

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, as amended by letter dated December 16, 2014 (ADAMS Accession No. ML14365A069).

Steel Tanks Exposed to Condensation. In LRA Table 3.4.2-3-IP2, the applicant stated that steel tanks exposed to an internal environment of condensation will be managed for loss of material by the Aboveground Steel Tanks Program. The applicant cited note E to indicate that for this component, material, and environment a different AMP than the one recommended in the GALL Report, Revision 1, is credited.

The staff's evaluation of the applicant's Aboveground Steel Tanks Program is documented in Section 3.0.3.2.1. The staff finds the applicant's proposal to manage the effects of aging using the Aboveground Steel Tanks Program acceptable because it is consistent with SRP-LR AMR item 3.4.1-30, as amended by LR-ISG-2012-02.

Steel Tanks Exposed to Treated Water. In LRA Table 3.4.2-3-IP2, the applicant stated that steel tanks exposed to an internal environment of treated water will be managed for loss of material by the Aboveground Steel Tanks Program. The applicant cited note E to indicate that for this component, material, and environment a different AMP than the one recommended in the GALL Report, Revision 1, is credited.

The staff's evaluation of the applicant's Aboveground Steel Tanks Program is documented in Section 3.0.3.2.1. The staff finds the applicant's proposal to manage the effects of aging using the Aboveground Steel Tanks Program acceptable because it is consistent with SRP-LR AMR item 3.4.1-62, as amended by LR-ISG-2012-02.

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

By letter dated December 14, 2017 (ADAMS Accession No. ML17360A157), the applicant amended LRA Table 3.4.2-5-4-IP2 by deleting copper alloy greater than 15 percent zinc strainer housings exposed externally to indoor air and internally to treated water. The staff noted that the applicant deleted two of three of the strainer housing items cited in the LRA and supplements. By letter dated May 8, 2018 (ADAMS Accession No. ML18134A036), the applicant provided clarification on the changes to LRA Table 3.4.2-5-4-IP2, which states "[t]he copper-alloy strainer housing in the city water system was erroneously included in the system review of the auxiliary feedwater pump room fire event for the city water system..." The applicant also stated that the third item for copper-alloy strainer housings should have also been deleted. The staff finds this acceptable because these deletions correct a mistake made in a previous change to the LRA, by letter dated December 12, 2013 (ADAMS Accession No. ML13354B873), which amended LRA tables associated with the auxiliary feedwater pump room fire event. The staff's evaluation of the scoping and screening of components in the auxiliary feedwater pump room fire event is documented in SER Section 2.3B.4.5.

3.4B.2.3 IP3 AMR Results Not Consistent with or Not Addressed in the GALL Report

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, as amended by letter dated December 16, 2014 (ADAMS Accession No. ML14365A069).

Steel Tanks Exposed to Condensation. In LRA Table 3.4.2-3-IP3, the applicant stated that steel tanks exposed to an internal environment of condensation will be managed for loss of material by the Aboveground Steel Tanks Program. The applicant cited note E to indicate that for this component, material, and environment a different AMP than the one recommended in the GALL Report, Revision 1, is credited.

The staff's evaluation of the applicant's Aboveground Steel Tanks Program is documented in Section 3.0.3.2.1. The staff finds the applicant's proposal to manage the effects of aging using the Aboveground Steel Tanks Program acceptable because it is consistent with SRP-LR AMR item 3.4.1-30, as amended by LR-ISG-2012-02.

Steel Tanks Exposed to Treated Water. In LRA Table 3.4.2-3-IP3, the applicant stated that steel tanks exposed to an internal environment of treated water will be managed for loss of material by the Aboveground Steel Tanks Program. The applicant cited note E to indicate that for this component, material, and environment a different AMP than the one recommended in the GALL Report, Revision 1, is credited.

The staff's evaluation of the applicant's Aboveground Steel Tanks Program is documented in Section 3.0.3.2.1. The staff finds the applicant's proposal to manage the effects of aging using the Aboveground Steel Tanks Program acceptable because it is consistent with SRP-LR AMR item 3.4.1-62, as amended by LR-ISG-2012-02.

3.4.2.4 Conclusion

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of combinations of material, environment, AERMs, and AMPs not consistent with, or 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).

3.5 Aging Management of Structures and Component Supports

3.5.2 Staff Evaluation

3.5.2.1 AMR Results Consistent with the GALL Report

By letter dated December 15, 2014 (ADAMS Accession No. ML14364A156), the applicant submitted an annual update to the LRA, identifying changes made to the CLB that materially affect the contents of the LRA. For IP2 and IP3 structures, the applicant revised LRA Table 3.5.2-3 to delete an AMR entry for the superheater stack exposed to air outdoor with an aging effect of loss of material and generic note C. The staff's evaluation of the removal of the superheater stack from the scope of license renewal is documented in SER Section 2.4.3.1 of this SSER.

SECTION 4
TIME-LIMITED AGING ANALYSES

4.2 <u>Reactor Vessel Neutron Embrittlement</u>

4.2.3 Pressure-Temperature Limits

4.2.3.1 Summary of Technical Information in the Application

By letter dated December 15, 2014 (Agencywide Documents and Access Management System (ADAMS) Accession No. ML14364A156), Entergy Nuclear Operations, Inc. (“Entergy” or “the applicant”) revised LRA Section 4.2.3 for Indian Point Nuclear Generating Unit 2 (IP2) pressure-temperature (P-T) limits and low-temperature overpressure protection (LTOP) requirements to extend them through 48 effective full-power years (EFPYs), and removed its previous statement that “[a]ddtional P-T limit analysis is not required at this time.”

4.2.3.2 Staff Evaluation

The staff of the U.S. Nuclear Regulatory Commission (NRC) reviewed the revision to LRA Section 4.2.3, providing time-limited aging analyses (TLAAs), to verify the applicant’s statement 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 confirmed that the P-T limits for the Indian Point units are located in the limiting conditions for operation (LCO) sections of the plant technical specifications (TS). Updates of the P-T limits are required to be submitted as license amendments and approved by the NRC before the expiration date of the current P-T limit curves contained in the LCOs. The staff determined that the applicant requested approval of IP2 P-T limit curves for the period of extended operation (i.e., for 48 EFPY) in a license amendment request dated February 6, 2013 (ADAMS Accession No. ML13052A018), and that the NRC approved the updated P-T limit curves for IP2 at 48 EFPY in a license amendment dated March 5, 2014 (ADAMS Accession No. ML14045A248). The staff noted that the applicant will be required to submit updated P-T limits for IP3 before the expiration of the current curves for the unit in the TS LCOs. The staff noted that Section 4.2.3.1.3.3 of the SRP-LR, Revision 2, identifies that the 10 CFR 50.90 license amendment process is an acceptable basis for accepting P-T limit TLAAs (applicable to those located in TS LCOs) in accordance with the requirement in 10 CFR 54.21(c)(1)(iii). Because P-T limit curves will be periodically updated in accordance with 10 CFR Part 50, Appendix G, and the license amendment process, the staff finds the P-T limits in accordance with 10 CFR 54.21(c)(1)(iii) acceptable because: (a) the applicant will use its 10 CFR 50.90 license amendment process to update the P-T limits for the units, (b) the staff has confirmed that this is in conformance with the basis in SRP-LR Section 4.2.3.1.3.3 for accepting P-T limits in accordance with 10 CFR 54.21(c)(1)(iii), and (c) this demonstrates that loss of fracture toughness, as analyzed for in the P-T limit curve analyses, will be adequately managed for the period of extended operation.

4.2.3.3 UFSAR Supplement

The applicant revised the UFSAR supplement summary description of its TLAA evaluation of P-T limits in LRA Section A.2.2.1.2 to add in LTOP requirements to its TS and to update the EFPY to 48 for both P-T limits and LTOP. This revision also included the elimination of the commitment to submit additional P-T curves before the period of extended operation. The applicant added the statement that P-T limit curves will continue to be updated, as required by Appendix G of 10 CFR Part 50, or as operational needs dictate. 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).

SECTION 5
REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

The staff has provided the Advisory Committee on Reactor Safeguards with a copy of this supplemental safety evaluation report.

SECTION 6
CONCLUSION

The staff concludes that the additional information provided by Entergy Nuclear Operations, Inc., does not alter the conclusions stated in the supplemental safety evaluation report (SSER), SSER 1, and SSER 2; and that the requirements of 10 CFR 54.29(a) have been met.

APPENDIX A

COMMITMENTS FOR LICENSE RENEWAL OF INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3

A. Commitments For License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3

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" or "the staff"), Entergy Nuclear Operations, Inc. ("Entergy" or "the applicant") made commitments related to aging management programs (AMPs) to manage aging effects for certain structures and components during the period of extended operation (PEO). The following table lists these commitments along with the applicant's stated implementation schedules and sources for each commitment. This list supersedes the list published in Appendix A of NUREG-1930, Supplement 2.

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS

No.	Commitment	Implementation Schedule	Source	LRA Section/Audit Item
1	Enhance the Aboveground 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 Aboveground Steel Tanks Program for IP2 and IP3 to require trending of thickness measurements when material loss is detected.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122	A.2.1.1 A.3.1.1 B.1.1
	Implement LRA Sections, A.2.1.1, A.3.1.1, and B.1.1, as shown in NL-14-147	IP2 & IP3: December 31, 2019	NL-14-147	A.2.1.1 A.3.1.1 B.1.1
	Implement LRA Sections, A.2.1.1 and B.1.1, as shown in NL-15-092	IP2 & IP3: December 31, 2019	NL-15-092	A.2.1.1 B.1.1
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. The Bolting Integrity Program manages loss of preload and loss of material for all external bolting	IP2: Complete IP3: Complete	NL-07-039 NL-07-153 NL-13-122	A.2.1.2 A.3.1.2 B.1.2 Audit Items 201,241, 270

No.	Commitment	Implementation Schedule	Source	LRA Section/Audit Item
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 program 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.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121 NL-09-106 NL-09-111 NL-11-101	A.2.1.5 A.3.1.5 B.1.6 Audit Item 173

No.	Commitment	Implementation Schedule	Source	LRA Section/Audit Item
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 storage 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 10 mg/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 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, EDG fuel oil storage 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. 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 to the storage tanks. Enhance the Diesel Fuel Monitoring Program to direct the addition of chemicals including biocide when the presence of biological activity is confirmed.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121 NL-08-057	A.2.1.8 A.3.1.8 B.1.9 Audit Items 128, 129, 132, 491, 492, 510

No.	Commitment	Implementation Schedule	Source	LRA Section/Audit Item
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 a accordance with 10 CFR 54.4(a)(2).	IP2: Complete	NL-07-039 NL-13-122	A.2.1.10 A.3.1.10 B.1.11
	Implement LRA Sections A.2.1.10, A.3.1.10, and B.1.11, as shown in NL-14-147	IP2 & IP3: December 31, 2019	NL-14-147	A.2.1.10 A.3.1.10 B.1.11
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.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121	A.2.1.11 A.3.1.11 B.1.12 Audit Item 164
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.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-15-121	A.2.1.12 A.3.1.12 B.1.13

No.	Commitment	Implementation Schedule	Source	LRA Section/Audit Item
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 replace all or test 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 if 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 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 foam based fire suppression tanks. Acceptance criteria will be enhanced to verify no significant corrosion.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-08-014	A.2.1.13 A.3.1.13 B.1.14 Audit Items 105, 106
	Implement LRA Sections A.2.1.13, A.3.1.13, and B.1.14, as shown in NL-14-147	IP2 & IP3: December 31, 2019	NL-14-147	A.2.1.13 A.3.1.13 B.1.14
	Implement LRA Sections A.2.1.13, A.3.1.13, and B.1.14, as shown in NL-15-019	IP2 & IP3: December 31, 2019	NL-15-019	A.2.1.13 A.3.1.13 B.1.14
	Implement LRA Sections A.2.1.13, A.3.1.13, and B.1.14, as shown in NL-15-092	IP2 & IP3: December 31, 2019	NL-15-092	A.2.1.13 A.3.1.13 B.1.14

No.	Commitment	Implementation Schedule	Source	LRA Section/Audit Item
	Implement LRA Sections A.2.1.13, A.3.1.13, and B.1.14, as shown in NL-16-122	IP2 & IP3: Complete	NL-16-122	A.2.1.13 A.3.1.13 B.1.14
	Implement LRA Sections A.2.1.13, A.3.1.13, and B.1.14, as shown in NL-17-052	IP2 & IP3: Complete	NL-17-052	A.2.1.13 A.3.1.13 B.1.14
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.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-15-121	A.2.1.15 A.3.1.15 B.1.16

No.	Commitment	Implementation Schedule	Source	LRA Section/Audit Item
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 • Charging pump crankcase oil coolers • Spent fuel pit heat exchangers • Secondary system steam generator sample coolers • Waste gas compressor heat exchangers • SBO/Appendix R diesel jacket water (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. 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 indication of tube erosion, vibration wear, corrosion, pitting, fouling, or scaling.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121 NL-09-018	A.2.1.16 A.3.1.16 B.1.17 Audit Item 52
11	Deleted		NL-09-056 NL-11-101	
12	Enhance the Masonry Wall Program for IP2 and IP3 to specify that the IP1 intake structure is included in the program	IP2: Complete IP3: Complete	NL-07-039 NL-13-122	A.2.1.18 A.3.1.18 B.1.19

No.	Commitment	Implementation Schedule	Source	LRA Section/Audit Item
13	Enhance the Metal-Enclosed Bus Inspection Program for IP2 and IP3 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. 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 such as thermography or contact resistance 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	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121 NL-08-057 NL-13-077	A.2.1.19 A.3.1.19 B.1.20 Audit Items 124, 133, 519
14	Implement the Non-EQ Bolted Cable Connections Program for IP2 and IP3 as described in LRA Section B.1.22	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-15-121	A.2.1.21 A.3.1.21 B.1.22
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 program described in NUREG-1801 Section XI.E3, Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121 NL-11-032 NL-11-096 NL-11-101	A.2.1.22 A.3.1.22 B.1.23 Audit Item 173

No.	Commitment	Implementation Schedule	Source	LRA Section/Audit Item
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 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.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121	A.2.1.23 A.3.1.23 B.1.24 Audit Item 173
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 program described in NUREG-1801 Section XI.E1, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121	A.2.1.24 A.3.1.24 B.1.25 Audit Item 173
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.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-11-101 NL-15-121	A.2.1.25 A.3.1.25 B.1.26
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.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121	A.2.1.26 A.3.1.26 B.1.27 Audit Item 173

No.	Commitment	Implementation Schedule	Source	LRA Section/Audit Item
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 1 Small-Bore Piping.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121	A.2.1.27 A.3.1.27 B.1.28 Audit Item 173
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 extended operation	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-15-121	A.2.1.28 A.3.1.28 B.1.29
	Implement LRA Sections A.2.1.28, A.3.1.28, and B.1.29, as shown in NL-16-122	IP2 & IP3: Complete	NL-16-122	A.2.1.28 A.3.1.28 B.1.29
	Implement LRA Sections A.2.1.28, A.3.1.28, and B.1.29, as shown in NL-17-052	IP2 & IP3: Complete	NL-17-052	A.2.1.28 A.3.1.28 B.1.29
	Implement LRA Sections ~~A.2.1.28~~[2], A.3.1.28, and B.1.29, as shown in NL-17-155	IP2 & IP3: December 31, 2018	NL-17-155	~~A.2.1.28~~ A.3.1.28 B.1.29
	Deleted		NL-17-161	B.1.29
	Implement LRA Section B.1.29, as shown in NL-18-010	IP2 & IP3: December 31, 2018	NL-18-010	B.1.29

[2] This section was erroneously identified in NL-17-15

No.	Commitment	Implementation Schedule	Source	LRA Section/Audit Item
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.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-15-121	A.2.1.31 A.3.1.31 B.1.32
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.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121	A.2.1.32 A.3.1.32 B.1.33 Audit Item 173
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.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122	A.2.1.34 A.3.1.34 B.1.35

No.	Commitment	Implementation Schedule	Source	LRA Section/Audit Item
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) • transformer/switchyard support structures (IP2) • waste holdup tank pits (IP2/3)	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121 NL-08-057 NL-13-077 NL-14-146	A.2.1.35 A.3.1.35 B.1.36 Audit Items 86, 87, 88, 417

No.	Commitment	Implementation Schedule	Source	LRA Section/Audit Item
	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			
	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.		NL-13-077	
	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 groundwater surrounding below-grade site structures and perform an engineering evaluation of the results from those samples for sulphates, pH and chlorides. Additionally, to		NL-08-127	Audit Item 360

No.	Commitment	Implementation Schedule	Source	LRA Section/Audit Item
	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. Enhance the Structures Monitoring Program to include more detailed quantitative acceptance criteria for inspections of concrete structures in accordance with ACI 349.3R, "Evaluation on Existing Nuclear Safety-Related Concrete Structures" prior to the period of extended operation.		NL-11-032 NL-11-101	Audit Item 358
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	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121	A.2.1.36 A.3.1.36 B.1.37 Audit Item 173
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	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153	A.2.1.37 A.3.1.37 B.1.38 Audit Item 173
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.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-08-057	A.2.1.39 A.3.1.39 B.1.40 Audit Item 509

No.	Commitment	Implementation Schedule	Source	LRA Section/Audit Item
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.	IP2: Complete	NL-07-039 NL-13-122	A.2.1.40 B.1.41
30	For aging management of the reactor vessel internals, IPEC will (1) participate in the industry programs for investigating and managing aging effects of 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.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-11-107	A.2.1.41 A.3.1.41
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	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-15-121	A.2.2.1.2 A.3.2.1.2 4.2.3
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	IP3: Approximately 6 years after entering the PEO	NL-07-039 NL-07-140 NL-08-014 NL-08-127	A.3.2.1.4 4.2.5

No.	Commitment	Implementation Schedule	Source	LRA Section/Audit Item
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 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	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-08-021 NL-10-082	A.2.2.2.3 A.3.2.2.3 4.3.3 Audit Item 146
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.	Complete	NL-13-122 NL-07-078 NL-08-074 NL-11-101	2.1.1.3.5

No.	Commitment	Implementation Schedule	Source	LRA Section/Audit Item
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. Any degradation will be evaluated for updating of the containment liner analyses as needed.	IP2: Complete IP3: Complete	NL-08-127 NL-13-122 NL-11-101 NL-15-121 NL-09-018	Audit Item 27
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. Additional core bore samples will be taken, if the leakage is not stopped, prior to the end of the first ten years of the period of extended operation. A sample of leakage fluid will be analyzed to determine the composition of the fluid. If additional core samples are taken prior to the end of the first ten years of the period of extended operation, a sample of leakage fluid will be analyzed.	IP2: Complete	NL-08-127 NL-13-122 NL-11-101 NL-09-056 NL-09-079	Audit Item 359
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.	IP2: Complete IP3: Complete	NL-08-127 NL-13-122	Audit Item 361
38	For Reactor Vessel Fluence, should future core loading patterns invalidate the basis for the projected values of RT_{PTS} or C_vUSE, updated calculations will be provided to the NRC	IP2: Complete IP3: Complete	NL-08-143 NL-13-122 NL-15-121	4.2.1
39	Deleted		NL-09-079	

No.	Commitment	Implementation Schedule	Source	LRA Section/Audit Item
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.	IP2: Complete IP3: Complete	NL-09-106 NL-13-122 NL-15-121	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
41	Deleted		NL-17-005	

No.	Commitment	Implementation Schedule	Source	LRA Section/Audit Item
42	IPEC will develop a plan for each unit to address the potential for cracking of the primary-to-secondary pressure boundary due to PWSCC of tube-to-tube sheet welds using one of two options: an analysis of the SG tube-to-tubesheet welds using one of the following two options. Option 1 (Analysis) IPEC will perform an analytical evaluation of the steam generator tube-to-tubesheet welds in order to establish a technical basis for either determining that the tubesheet cladding and welds are not susceptible to PWSCC, or redefining the pressure boundary in which the tube-to-tubesheet weld is no longer included and, therefore, is not required for reactor coolant pressure boundary function. The redefinition of the reactor coolant pressure boundary must be approved by the NRC as a license amendment request. Option 2 (Inspection) IPEC will perform a one-time inspection of a representative number of tube-to-tubesheet welds in each steam generator to determine if PWSCC cracking is present. If weld cracking is identified: The condition will be resolved through repair or engineering evaluation to justify continued service, as appropriate, and An ongoing monitoring program will be established to perform routine tube-to-tubesheet weld inspections for the remaining life of the steam generators	IP2: Complete IP3: Complete IP2: Not Applicable IP3: Not Applicable	NL-11-032 NL-11-074 NL-11-090 NL-11-096 NL-17-005	
43	IPEC will review design basis ASME Code Class 1 fatigue evaluations to determine whether the NUREG/CR-6260 locations that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting locations for the IP2 and IP3 configurations. If more limiting locations are identified, the most limiting location will be evaluated for the effects of the reactor coolant environment on fatigue usage. IPEC will use the NUREG/CR-6909 methodology in the evaluation of the limiting locations consisting of nickel alloy, if any	IP2: Complete IP3: Complete	NL-11-032 NL-13-122 NL-11-101 NL-15-121	4.3.3
44	IPEC will include written explanation and justification of any user intervention in future evaluations using the WESTEMS “Design CUF” module.	IP2: Complete IP3: Complete	NL-11-032 NL-13-122 NL-11-101 NL-15-121	

No.	Commitment	Implementation Schedule	Source	LRA Section/Audit Item
45	IPEC will not use the NB-3600 option of the WESTEMS program in future design calculations until the issues identified during the NRC review of the program have been resolved.	IP2: Complete IP3: Complete	NL-11-032 NL-13-122 NL-11-101 NL-15-121	
46	Include in the IP2 ISI Program that IPEC will perform twenty-five volumetric weld metal inspections of socket welds during each 10-year ISI interval scheduled as specified by IWB-2412 of the ASME Section XI Code during the period of extended operation. In lieu of volumetric examinations, destructive examinations may be performed, where one destructive examination may be substituted for two volumetric examinations.	IP2: Complete	NL-11-032 NL-13-122 NL-11-074	
47	Deleted		NL-14-093	
48	Entergy will visually inspect IPEC underground piping within the scope of license renewal and subject to aging management review prior to the period of extended operation and then on a frequency of at least once every two years during the period of extended operation. This inspection frequency will be maintained unless the piping is subsequently coated in accordance with the preventive actions specified in NUREG-1801 Section XI.M41 as modified by LP-ISG-2011-03. Visual inspections will be supplemented with surface or volumetric non-destructive testing if indications of significant loss of material are observed. Consistent with revised NUREG-1801 Section XI.M41, such adverse indications will be entered into the plant corrective action program for evaluation of extent of condition and for determination of appropriate corrective actions (e.g., increased inspection frequency, repair, replacement).	IP2: Complete IP3: Complete	NL-12-174 NL-13-122 NL-15-121	
49	Recalculate each of the limiting CUFs provided in Section 4.3 of the LRA for the reactor vessel internals to include the reactor coolant environment effects (F_{en}) as provided in the IPEC Fatigue Monitoring Program using NUREG/CR-5704 or NUREG/CR-6909. In accordance with the corrective actions include further CUF re-analysis, and/or repair or replacement of the affected components prior to the CUF_{en} reaching 1.0	IP2: Complete IP3: Complete	NL-13-052 NL-13-122 NL-15-121	A.2.2.2 A.3.2.2

No.	Commitment	Implementation Schedule	Source	LRA Section/Audit Item
50	Replace the IP2 split pins during the 2016 refueling outage (2R22).	IP2: Complete IP3: N/A	NL-13-122 NL-14-067	A.2.1.41 B.1.42
51	Enhance the Service Water Integrity Program by implementing LRA Sections A.2.1.33, A.3.1.33, and B.1.34, as shown in NL-14-147	IP2 & IP3: Complete	NL-14-147	A.2.1.33 A.3.1.33 B.1.34
	Implement LRA Sections A.2.1.33, A.3.1.33 and B.1.34, as shown in NL-16-122	IP2 & IP3: Complete	NL-16-122	A.2.1.33 A.3.1.33 B.1.34
	Implement LRA Sections A.2.1.33, A.3.1.33 and B.1.34, as shown in NL-17-052	IP2 & IP3: Complete	NL-17-052	A.2.1.33 A.3.1.33 B.1.34
	Implement LRA Sections A.2.1.33, A.3.1.33 and B.1.34, as shown in NL-17-155	IP2 & IP3: December 31, 2018	NL-17-155	A.2.1.33 A.3.1.33 B.1.34
	Implement LRA Sections A.2.1.33, A.3.1.33 and B.1.34, as shown in NL-17-161	IP2 & IP3: December 31, 2018	NL-17-161	A.2.1.33 A.3.1.33 B.1.34
52	Implement the Coating Integrity Program for IP2 and IP3 as described in LRA Section B.1.42, as shown in NL-15-019	IP2 & IP3: December 31, 2024	NL-15-019	A.2.1.42 A.3.1.42 B.1.43

No.	Commitment	Implementation Schedule	Source	LRA Section/Audit Item
53	Revise Bolting Integrity Program to include visual inspection of a representative sample of closure bolting (bolt heads, nuts, and threads) from components with an internal environment of a clear gas, such as air or nitrogen. A representative sample will be 20% of the population (for each bolting material and environment combination) up to a maximum of 25 fasteners during each 10-year period of the period of extended operation. The inspections will be performed when the bolting is removed to the extent that the bolting threads and bolt heads are accessible for inspections that cannot be performed during visual inspection with the threaded fastener installed.	Complete	NL-17-053	A.2.1.2 A.3.1.2 B.1.2
54	Enhance the Steam Generator Integrity Program as follows: • Revise applicable procedures to specify a general visual inspection of the steam generator channel head.	Complete	NL-17-060	A.2.1.34 A.3.1.34 B.1.35
55	Revise the Buried Piping and Tanks Inspection Program for IP2 and IP3 to incorporate the changes shown in LRA Sections A.2.1.5 and A.3.1.5 in letter NL-17-084	Complete	NL-17-084	A.2.1.5 A.3.1.5

APPENDIX C

PRINCIPAL CONTRIBUTORS

C. Principal Contributors

This appendix lists the principal contributors for the development of this supplement to the safety evaluation report and their areas of responsibility.

APPENDIX C: PRINCIPAL CONTRIBUTORS

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Hovanec, Chris	Reviewer – Mechanical Systems
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Morey, Dennis	Management Oversight
Oesterle, Eric	Management Oversight
Poehler, Jeff	Reviewer – Reactor Systems
Prinaris, Andrew	Reviewer – Containment Systems
Ruffin, Steve	Management Oversight
Wise, John	Reviewer – Mechanical Systems
Wittick, Brian	Management Oversight
Wong, Albert	Project Management

APPENDIX D

REFERENCES

D. REFERENCES

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