IPRenewal NPEmails

From: Green, Kimberly
Sent: Friday, November 07, 2014 2:34 PM
To: Waters, Roger M. (rwater1@entergy.com)
Cc: IPRenewal NPEmails
Subject: Supplement 2 to the SER
Attachments: ML14288A608.pdf; ML14310A803.pdf

Roger,

Attached are electronic copies of the transmittal letter and Supplement 2 to the SER. These documents have been placed in the mail and will be publicly available in ADAMS in next day or so.

For your information, the accession numbers in ADAMS are:

ML14288A608 – transmittal letter
ML14310A803 – SSER 2

If you have any questions, please let me know.

Kim

Hearing Identifier: IndianPointUnits2and3NonPublic_EX
Email Number: 4706

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From: Green, Kimberly

Created By: Kimberly.Green@nrc.gov

Recipients:
"IPRenewal NPEmails" <IPRenewal.NPEmails@nrc.gov>
Tracking Status: None
"Waters, Roger M. (rwater1@entergy.com)" <rwater1@entergy.com>
Tracking Status: None

Post Office: HQCLSTR01.nrc.gov

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November 6, 2014

Vice President, Operations
Entergy Nuclear Operations, Inc.
Indian Point Energy Center
450 Broadway, GSB
P.O. Box 249
Buchanan, NY 10511-0249

SUBJECT: SUPPLEMENT 2 TO THE SAFETY EVALUATION REPORT RELATED TO THE LICENSE RENEWAL OF INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3

Dear Sir or Madam:

By letter dated April 23, 2007, as supplemented by letters dated May 3, and June 21, 2007, Entergy Nuclear Operations, Inc., (Entergy) submitted to the U.S. Nuclear Regulatory Commission (NRC) an application to renew the Indian Point Nuclear Generating Unit Nos. 2 and 3, (IP2 and IP3) operating licenses for an additional 20 years beyond the expirations of the initial operating licenses on September 28, 2013, for IP2, and on December 12, 2015, for IP3. The license renewal application (LRA) was submitted pursuant to Title 10 of the *Code of Federal Regulations* Part 54 (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants." The NRC staff determined that the LRA was complete and acceptable for docketing on July 25, 2007.

The NRC staff reviewed the LRA for compliance with the requirements of 10 CFR Part 54, and issued its findings in NUREG-1930, "Safety Evaluation Report [SER] Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3," on August 11, 2009. The SER was published in November 2009, following the staff's receipt of comments from the Advisory Committee on Reactor Safeguards (ACRS). In August 2011, the staff issued Supplement 1 to NUREG-1930, which documented the staff's review of supplemental information provided by Entergy since the issuance of the SER as documented in NUREG-1930.

The enclosed Supplement 2 to the SER documents the staff's review of additional information provided by Entergy in annual updates, LRA amendments, and responses to staff requests for additional information since the issuance of Supplement 1 to the SER.

If you have any questions regarding this matter, please contact Kimberly Green at 301-415-1627, or by e-mail at kimberly.green@nrc.gov.

Sincerely,

/RA/

Christopher G. Miller, Director
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-247 and 50-286

Enclosure:
As stated

cc w/encl: Listserv

If you have any questions regarding this matter, please contact Kimberly Green at 301-415-1627, or by e-mail at kimberly.green@nrc.gov.

Sincerely,

/RA/

Christopher G. Miller, Director
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-247 and 50-286

Enclosure:
As stated

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Letter to Entergy Nuclear Operations, Inc. from Chris Miller dated November 6, 2014

SUBJECT: SUPPLEMENT 2 TO THE SAFETY EVALUATION REPORT RELATED TO THE LICENSE RENEWAL OF INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3

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Safety Evaluation Report

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

Supplement 2

Docket Numbers 50-247 and 50-286

Entergy Nuclear Operations, Inc.

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

November 2014

ABSTRACT

This document is the second supplement to NUREG-1930, "Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3," for the license renewal application (LRA) for Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3). By letter dated April 23, 2007, as supplemented by letters dated May 3 and June 21, 2007, 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 Numbers DPR-26 and DPR-64, respectively) for a period of 20 years beyond the expirations of the initial operating licenses at midnight on September 28, 2013, for IP2, and at midnight on December 12, 2015, for IP3. The Commission's regulation in 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 *United States Code* (U.S.C.) Section 558(c). Under this regulation, if a licensee 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 U.S. Nuclear Regulatory Commission (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.

The staff published its safety evaluation report (SER) in the two volumes of NUREG-1930 in November 2009, which summarized the results of its safety review of the LRA 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), which documented the staff's review of supplemental information provided by the applicant since the issuance of the SER as documented in NUREG-1930. This supplement to NUREG-1930 (SSER 2) documents the staff's review of supplemental information provided by the applicant since the issuance of the SSER 1. This information includes information committed to by Entergy as documented in Commitment No. 30 (pertaining to reactor vessel internals), information required by 10 CFR 54.21(b), updated information and commitments, as well as information provided in response to staff requests for additional information. This document discusses only the changes to the SER and SSER 1.

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ABBREVIATIONS AND ACRONYMS

A/LAI	Applicant/Licensee Action Item
AC	alternating current
ACI	American Concrete Institute
ADAMS	Agencywide Documents Access and Management System
AERM	aging effect requiring management
AMP	aging management program
AMR	aging management review
APEC	area potential—earth current
ASA	American Standards Association [now the American National Standards Institute (ANSI)]
ASME	[formerly an abbreviation for the American Society of Mechanical Engineers, now part of the organization's formal name]
B&W	Babcock & Wilcox
BSD	black start diesel
BWR	boiling water reactor
CASS	cast austenitic stainless steel
CE	Combustion Engineering
CEA	control element assembly
CFR	*Code of Federal Regulations*
CII	containment inservice inspection
CLB	current licensing basis
CO_2	carbon dioxide
CP	cathodic protection
CRGT	control rod guide tube
CUF	cumulative usage factor
CUF_{en}	environmentally-adjusted cumulative usage factor
DFP	diesel fire pump

dpa	displacement(s) per atom
EDG	emergency diesel generator
EFPH	effective full-power hour(s)
EFPY	effective full-power year(s)
EPRI	Electric Power Research Institute
EQ	environmental qualification
EVT	enhanced visual testing
F_{en}	environmental fatigue correction factor
FMECA	failure modes, effects, and criticality analysis/analyses
FSAR	final safety analysis report
GALL	Generic Aging Lessons Learned [Report]
GL	generic letter
GT	gas turbine
HAZ	heat-affected zone
HTH	high-temperature annealed and aged condition heat treatment
HVAC	heating, ventilation, and air conditioning
IASCC	irradiation-assisted stress corrosion cracking
IE	[neutron] irradiation embrittlement
I&E	inspection and evaluation
IGSCC	intergranular stress corrosion cracking
IPEC	Indian Point Energy Center
IP1	Indian Point Nuclear Generating Unit 1
IP2	Indian Point Nuclear Generating Unit 2
IP3	Indian Point Nuclear Generating Unit 3
ISG	interim staff guidance
ISI	inservice inspection

ksi	kilopound(s) per square inch
kV	kilovolt(s)
L^3P	low-low-leakage loading pattern
L^4P	low-low-low-leakage loading pattern
LOCA	loss-of-coolant accident
LR-ISG	license renewal interim staff guidance
LRA	license renewal application
LRSS	lower radial support system
LWR	light-water reactor
MEB	metal-enclosed bus
MIC	microbiologically influenced corrosion
MoS_2	molybdenum disulfide
MRP	Materials Reliability Program
mV	millivolt(s)
NDE	nondestructive examination
NEI	Nuclear Energy Institute
NFPA	National Fire Protection Association
NRC	U.S. Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NSSS	nuclear steam supply system
OE	operating experience
P-T	pressure/temperature [curve]
PEO	period of extended operation
PT	[liquid] penetrant testing
PTS	pressurized thermal shock
PVC	polyvinyl chloride

PWR	pressurized water reactor
PWROG	Pressurized Water Reactor Owners Group
PWSCC	primary water stress corrosion cracking
RAI	request for additional information
RCCA	rod cluster control assembly
RCP	reactor coolant pump
RHR	residual heat removal
RIS	Regulatory Issue Summary
RPV	reactor pressure vessel
RT_{PTS}	reference temperature for pressurized thermal shock
RVI	reactor vessel internal(s)
RWST	refueling water storage tank
SBO	station blackout
SC	structure and component
SCC	stress corrosion cracking
SE	safety evaluation
SER	safety evaluation report
SPU	stretch power uprate
SRP-LR	standard review plan for review of license renewal applications for nuclear power plants
SS	stainless steel
SSER	supplemental safety evaluation report
SSC	system, structure, or component
SSCs	systems, structures, and components
TE	thermal embrittlement
TJ	technical justification
TLAA	time-limited aging analysis
TS	technical specification

UCP	upper core plate
UFSAR	updated final safety analysis report
USP	upper support plate
UT	ultrasonic testing
V	volt(s)
VAC	volt(s) of alternating current
VT	visual testing
W	Westinghouse

SECTION 1

INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

This document is the second supplement to NUREG-1930, “Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3,” for the license renewal application (LRA) for Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3). By letter dated April 23, 2007, as supplemented by letters dated May 3 and June 21, 2007, 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 Numbers DPR-26 and DPR-64, respectively) for a period of 20 years beyond the expirations of the initial operating licenses at midnight on September 28, 2013, for IP2, and at midnight on December 12, 2015, for IP3. The Commission’s regulation in 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 *United States Code* (U.S.C.) Section 558(c). Under this regulation, if a licensee 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 U.S. Nuclear Regulatory Commission (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.

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SECTION 2

STRUCTURES AND COMPONENTS SUBJECT TO AGING MANAGEMENT REVIEW

2.3 Scoping and Screening Results: Mechanical Systems

2.3.1.2 Reactor Vessel Internals

2.3.1.2.1 Summary of Technical Information in Application

In Sections 2.3A.1.2 and 2.3B.1.2 of the SER, with regard to the scoping and screening of the reactor vessel intervals (RVI), the staff concluded that that the applicant had adequately identified the RVI components within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an aging management review (AMR) as required by 10 CFR 54.21(a)(1). In the SER, Section 2.3A.1.2 addressed IP2 and Section 2.3B.1.2 addressed IP3; however, the section below addresses both IP2 and IP3 because the scoping and screening information is identical.

In LRA Amendment 9 (Ref. 1), changes to some of the component names were made in Section 2.3.1.2, which describes and lists the major assemblies and their subcomponents that form the RVI. A revised Table 2.3.1-2-IP2, [1] "Reactor Vessel Internals Components Subject to Aging Management," contains similar changes. The previous components were in some cases subdivided into more subcomponents. The intended functions from the previous components were maintained for the new components' names, although in some cases an intended function specific to only a particular subcomponent was maintained only for that subcomponent. For example, five core barrel assembly subcomponents (ring, shell, thermal shield, flange, and axial flexure plates) were previously combined in one table entry in Table 2.3.1-2-IP2. In LRA Amendment 9, three core barrel assembly subcomponents (ring, shell, and thermal shield) have been placed in one table entry while the core barrel assembly, axial flexure plate (thermal shield flexures), and core barrel assembly flange each have a separate table entry. Previously, all these subcomponents had intended functions of structural support, flow distribution, and shielding. In LRA Amendment 9, the core barrel assembly, axial flexure plates (thermal shield flexures) and the core barrel assembly flange only have the intended function of structural support, while the other three core barrel assembly subcomponents (ring, shell, and thermal shield) continue to have the intended functions of structural support, flow distribution, and shielding.

2.3.1.2.2 Staff Evaluation

The staff notes that the previous RVI components and subcomponents have in some cases been subdivided into additional subcomponents, although no components were removed from

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[1] This table was incorrectly numbered as Table 2.3.1-4-IP2 in LRA Amendment 9, which was corrected in the RAI 1 response.

scope. The changes appear to have been made to facilitate alignment of the components with the component designations for RVI components from Revision 2 of NUREG-1801, “Generic Aging Lessons Learned Report” (the GALL Report), and Electric Power Research Institute (EPRI) Materials Reliability Program (MRP) Technical Report 1016596, “Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-Rev. 0)” (Ref. 2). However, the component designations are not identical to those in Revision 2 of the GALL Report or in EPRI MRP Technical Report 1022863, “Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A)” (Ref. 3). The staff’s evaluation of the equivalency of the Indian Point Energy Center (IPEC) RVI component designations to those in MRP-227-A is provided in Section 3.0.3.3.10 of this SER supplement. The staff compared the revised intended functions to the information in Appendix C, “Component Functional Descriptions for Westinghouse Reactor Internals,” to MRP-191, “Materials Reliability Program: Screening, Categorization, and Ranking of Reactor Internals Components for Westinghouse and Combustion Engineering PWR Design” (Ref. 16), and finds that the revised intended functions are consistent with the intended functions used to develop the aging management recommendations of MRP-227-A. Therefore, the staff finds the revised intended functions acceptable.

LRA Amendment 9 states that LRA Tables 2.3.1-2-IP2 and 2.3.1-2-IP3 list the mechanical components subject to AMR and component intended functions for the RVI. However, Table 2.3.1-2-IP3 is missing, and the table for IP2 listing the components subject to AMR is numbered Table 2.3.1-4-IP2. Therefore, in Request for Additional Information (RAI) 1, the staff requested that the applicant provide Table 2.3.1-2-IP3 and correct the numbering of the table for IP2. In its response to RAI 1 by letter dated June 14, 2012 (Ref. 4), the applicant provided a correctly numbered Table 2.3.1-2-IP2 and provided Table 2.3.1-2-IP3, which the applicant stated is identical to Table 2.3.1-2-IP2. The staff reviewed the revised tables and finds that they are acceptable. The staff’s concern in RAI 1 is, therefore, resolved.

2.3.1.2.3 Conclusion

The staff reviewed LRA Amendment 9 to determine whether the changes the applicant made to the component descriptions change the staff’s previous conclusions that the applicant had identified all of the systems, structures, and components (SSCs) within the scope of license renewal and that the applicant had correctly identified all components subject to an AMR. On the basis of its review, the staff concludes that the changes to the RVI components and subcomponents within the scope of license renewal are acceptable and sustain the previous conclusion that the applicant has appropriately identified those components within scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

SECTION 3

AGING MANAGEMENT REVIEW RESULTS

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

3.0.3 Aging Management Programs

3.0.3.1 Aging Management Programs Consistent with the GALL Report

3.0.3.1.2 Buried Piping and Tanks Inspection Program

Summary of Technical Information in the Application. By letters dated January 30, 2012, September 26, 2012, October 18, 2012, November 29, 2012, March 5, 2013, and July 15, 2013, the applicant provided additional information related to the Buried Piping and Tanks Inspection Program after the issuance of Supplement 1 to the SER. The changes were identified as omissions or corrections related to systems and components credited in the auxiliary feedwater pump room fire event, identification of underground piping components based on a change in understanding of the definition of "underground piping," and a change in the criteria for selecting buried pipe inspection locations based on changes in License Renewal Interim Staff Guidance (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.'" The additional information is discussed below.

By letters dated June 12, 2013 and September 3, 2013, the staff issued RAIs 3.0.3.1.2-4 and 3.0.3.1.2-4a respectively, requesting that the applicant address questions related to cathodic protection (CP) effectiveness and acceptance criteria and the extent-of-condition criteria when backfill is found to have damaged in-scope buried piping coatings. The applicant responded to these RAIs by letters dated July 24, 2013, and October 3, 2013, respectively.

Staff Evaluation. The staff's previous evaluation of the applicant's proposed Buried Piping and Tanks Inspection Program is documented in Section 3.0.3.1.2 of SSER 1.

Changes Related to the Scope of Program. By letters dated January 30, and September 26, 2012, the applicant added the Indian Point Nuclear Generating Unit No. 1 (IP1) river water service and the IP2 circulating water systems to the scope of the Buried Piping and Tanks Inspection Program. The applicant added portions of these systems to the scope of license renewal as a result of a further evaluation of the auxiliary feedwater pump room fire event (see Section 2.3A.4.5 of the SER). Additionally, as amended by letter dated July 15, 2013, the applicant added the IP2 instrument air system to the scope of this program because it identified buried in-scope copper-alloy piping exposed to soil with an intended function that supports the auxiliary feedwater pump room fire event. The staff finds these changes acceptable because the applicant, on identifying buried components with an intended function that supports the auxiliary feedwater pump room fire event, properly added them to the scope of the Buried Piping and Tanks Inspection Program.

Changes Related to Selecting Inspection Locations. As amended by letter dated March 5, 2013, the applicant revised its program to not exclusively differentiate inspection locations based on the code or safety-related classification of the piping systems or on whether the piping contained hazardous materials. The applicant stated that inspection locations will be based on plant-specific risk ranking. The applicant also stated that the total number of inspections would not change. The number of excavated direct visual inspections is summarized as follows:

- at IP2, at least 20 locations of steel piping will be inspected in the 10-year period before the period of extended operation, and

- at IP3, at least 11 locations of steel piping and 3 locations of stainless steel piping will be inspected in the 10-year period before the period of extended operation, so

- in summary, prior to the period of extended operation, there will be 31 inspections of steel piping and 3 inspections of stainless steel piping;

- at IP2, at least 14 locations of steel piping will be inspected in each 10-year period during the period of extended operation, and

- at IP3, at least 14 locations of steel piping and 2 locations of stainless steel piping will be inspected in each 10-year period during the period of extended operation, so

- in summary, during each 10-year period during the period of extended operation, there will be 28 inspections of steel piping and 2 inspections of stainless steel piping.

The staff finds the applicant’s change acceptable because the change is consistent with the guidance in LR-ISG-2011-03, which eliminated the code or safety-related and hazardous materials categorization in lieu of the applicant selecting inspection locations based on the risk ranking of the buried piping systems.

Changes Related to Underground Piping. In its response to RAI 3.0.3.1.2-1 dated March 28, 2011, the applicant stated that it did not have any underground piping. The staff conducted a conference call with the applicant on October 11, 2012, in which the applicant sought guidance on the use of the term “restricted” as it related to its use in the description of underground piping contained in the “Program Description” in LR-ISG-2011-03. During this call, the staff stated that piping located in vaults, for which access requires more than simply opening a locked access cover, should be classified as underground piping.

Based on this guidance, the applicant amended its LRA by letter dated October 18, 2012. The applicant stated that portions of the IP3 service water, IP3 city water, and IP2 and IP3 fuel-oil systems are located in vaults and are therefore considered underground piping. The applicant also stated that the underground components would be inspected under the Buried Piping and Tanks Inspection Program at a frequency that meets or exceeds the recommendations of GALL Report AMP XI.M41, “Buried and Underground Piping and Tanks.” The October 18, 2012, letter did not address whether the piping was coated. By letter dated November 29, 2012, the applicant stated that the underground piping was not coated. The applicant added Commitment No. 48, which states that underground piping will be visually inspected prior to the period of extended operation and then on a frequency of at least once every 2 years during the period of extended operation. The commitment further states that the inspection frequency will be maintained unless the piping is subsequently coated in accordance with LR-ISG-2011-03. Visual inspections will be augmented with surface or volumetric inspections if indications of significant loss of material are observed, and adverse indications will be entered into the corrective action program. The applicant revised LRA Sections A.2.1.5, A.3.1.5, and B.1.6 to reflect the inclusion of underground piping in the program, and the inspection details were included in Commitment No. 48.

The staff finds the changes acceptable because: (a) although the piping is not coated, the applicant has significantly increased the frequency of inspections, every 2 years versus every 10 years, as recommended in LR-ISG-2011-03; (b) the applicant is inspecting all of the underground piping instead of two percent of the pipe, as recommended in LR-ISG-2011-03; (c) the visual inspections are capable of detecting loss of material before the point at which the intended function of the piping would not be met; (d) the inspection frequencies will remain at every 2 years unless the piping is coated; and (e) the commitment has been incorporated in the updated final safety analysis report (UFSAR) supplement.

Changes Related to Cathodic Protection. The applicant's response to RAI 3.0.3.1.2-1 stated that the only cathodically protected in-scope buried piping was the city water line in the vicinity of the Algonquin gas pipelines. However, the staff understood that CP had recently been installed on portions of the auxiliary feedwater system and was being considered for installation on the service water system. The inclusion of safety-related systems, such as auxiliary feedwater and service water, in the scope of systems protected by CP resulted in the staff's need to evaluate the parameters monitored and the acceptance criteria for the CP system in order for CP to be credited as an input for selection of risk-ranked piping inspection locations. By letter dated June 12, 2013, the staff issued RAI 3.0.3.1.2-4, with Item (1) requesting that the applicant:

a) State how often CP surveys will be conducted.

b) State what parameters will be monitored during CP surveys.

c) State how the availability of the CP system will be monitored and state the associated availability acceptance criterion that will be used in order to credit the CP system during the risk ranking process.

d) State how the effectiveness of the CP system will be monitored and state the associated effectiveness acceptance criterion that will be used in order to credit the CP system during the risk ranking process.

e) State the following:

    - Whether an instant on negative 850 [millivolt] mV relative to a copper/copper sulfate reference electrode, instant off negative 850 mV relative to a copper/copper sulfate reference electrode, 100 mV minimum polarization, or alternative acceptance criteria will be used to demonstrate the effectiveness of the CP system.

    - If the instant on negative 850 mV relative to a copper/copper sulfate reference electrode criterion is used, state how voltage drops other than those across the structure to electrolyte boundary will be determined.

    - If the 100 mV minimum polarization criterion is used, state how it is known that the effects of mixed potentials (e.g., presence of a copper grounding grid) are minimal and why the most anodic metal in the system is adequately protected.

- If an alternative means of demonstrating the effectiveness of the CP system is used, state the alternative acceptance criteria.

f) State the upper level voltage acceptance criterion (i.e., no more negative than) for CP and the basis for the value.

g) State what CP system parameters will be trended.

h) Appropriately revise License Renewal Application (LRA) Sections A.2.1.5 and A.3.1.5 to reflect crediting the CP system as a preventive measure for portions of the buried in scope piping.

In its response dated July 24, 2013, the applicant stated that, based on plant-specific operating experience, CP was installed on portions of the IP2 auxiliary feedwater/condensate buried piping in early 2012 and CP is currently being installed on portions of the IP3 condensate storage lines. The applicant also stated that, based on inspection results demonstrating limited coating degradation and acceptable wall thickness indicated by ultrasonic testing (UT) measurements, the applicant is evaluating whether installation of CP on IP2 service water piping is necessary. The responses to specific RAI questions are as follows:

a) CP surveys will be conducted at least once every 12 months.

b) The CP surveys will monitor the instant-off pipe-to-soil potentials.

c) CP availability will be determined by calculating the percent of time that the rectifiers are in service (i.e., current output greater than zero volts or zero amps). Out-of-service time for testing is not counted against the availability. The CP availability criterion is 85 percent or more.

d) CP effectiveness will be determined by measuring soil-to-pipe potential. The test points are evaluated against an instant-off negative 850 mV relative to a copper/copper sulfate reference electrode criterion. If a test point does not meet this criterion, it is evaluated against a 100 mV polarization criterion, provided that the test location is evaluated for the potential (adverse) influence of mixed metals. The CP effectiveness criterion is 80 percent or more of the test points meeting the above criteria.

e) Acceptance criteria are as follows:

- A soil-to-pipe instant-off negative 850 mV relative to a copper/copper sulfate reference electrode criterion is the preferred acceptance criterion.

- The instant-on negative 850 mV relative to a copper/copper sulfate reference electrode criterion will not be used.

- The 100 mV polarization criterion will be used when the instant-off negative 850 mV is not met, subject to: (a) the effect of mixed metals is evaluated; (b) for new CP system installations, the absence of exposed copper grounding is confirmed, and

(c) for existing CP systems, corrosion monitoring probes may be installed near the pipe to confirm adequate protection for the in-scope buried components.

- The use of alternative means for demonstrating CP effectiveness is not anticipated.

f) An upper voltage acceptance criterion of negative 1200 mV will be used for instant-off measurements.

g) Rectifier current output, test station potential measurements, and rectifier voltage output will be trended.

h) In regard to revising the LRA to reflect crediting the CP system as a preventive measure for portions of the buried in-scope piping, the applicant stated:

> The IPEC CP systems will not be credited as preventive measures for the in-scope buried piping. CP systems installed to protect license renewal in-scope buried piping will be used to minimize corrosion in areas that have been found susceptible to corrosion based on indirect inspections (i.e., guided wave inspections) or testing (e.g., APEC [area potential—earth current] surveys). To the extent they are proven effective, the CP systems at IPEC will be considered in risk ranking to ensure that the in-scope buried piping systems that are more susceptible to external corrosion continue to receive a higher risk ranking when determining inspection priority. Therefore, no revision to License Renewal Application Sections A.2.1.5 and A.3.1.5 is necessary because Entergy is not crediting the CP system as a preventive measure for in-scope buried piping.

The staff finds the applicant’s response to RAI 3.0.3.1.2-4, Item (1), sections (a), (b), (c), (f), and (g) acceptable, and portions of (d) and (e) acceptable, because the periodicity of CP surveys, monitoring for instant-off pipe-to-soil potentials, an 85-percent availability criterion, an 80-percent effectiveness criterion, an upper voltage limit of negative 1200 mV, and the parameters that will be trended are consistent with the guidance in LR-ISG-2011-03, and therefore are sufficient to determine whether a CP system has performed adequately enough to credit it for determining appropriate pipe inspection locations.

The staff did not find the applicant’s response to other portions of (d) and (e) acceptable because, although LR-ISG-2011-03 allows the use of the 100 mV polarization criterion when the effects of mixed potentials are minimal and the most anodic metal in the system is adequately protected, the applicant did not provide a sufficient basis for how this will be determined. The staff did not find the applicant’s response to section (h) acceptable because the program and UFSAR supplement should reflect the purpose of the CP system (e.g., input for risk ranking of inspection locations) and its acceptance criteria. By letter dated September 3, 2013, the staff issued RAI 3.0.3.1.2-4a requesting that the applicant: (a) provide additional information related to the use of corrosion rate monitoring devices and coupons if the 100 mV polarization criterion will be used; (b) revise its Buried Piping and Tanks Inspection Program to reflect the purpose of the CP system and its acceptance criteria; and (c) revise the UFSAR Supplement to reflect the purpose of the CP system.

In its response dated October 3, 2013, the applicant stated that for the purposes of crediting the cathodic protection system, it will use the polarization potential of at least (i.e., more negative than) -850 mV instant-off as the CP acceptance criterion as well as an upper voltage acceptance criterion of -1200 mV. The applicant revised its Buried Piping and Tanks Inspection Program to reflect the purpose of the CP system and include the acceptance criteria as described above. The applicant also revised its UFSAR supplements to reflect the purpose of the CP system.

The staff finds the applicant's response to RAI 3.0.3.1.2-4a acceptable because: (a) the applicant will only use the -850 mV instant-off criterion with an upper voltage acceptance criterion of -1200 mV, (b) the program reflects the purpose of CP system and its acceptance criteria, (c) the UFSAR Supplements reflect the purpose of the CP system, and (d) the acceptance criteria and UFSAR Supplement program descriptions are consistent with the guidance in LR-ISG-2011-03. The staff's concerns described in RAIs 3.0.3.1.2 4, Item (1), and 3.0.3.1.2-4a are resolved.

Operating Experience. The staff noted that exhibits filed in the evidentiary record during hearings conducted in association with the Indian Point LRA described direct visual inspections of recently excavated buried in-scope piping that detected rocks in the backfill in the vicinity of piping. By letter dated June 12, 2013, the staff issued RAI 3.0.3.1.2 4, Item (2), requesting that the applicant state what criteria will be used to conduct an extent-of-condition evaluation when non-conforming backfill causes damage to coatings with base metal exposure, as discovered during excavated direct visual inspections.

By letter dated July 24, 2013, the applicant stated that it had excavated and directly visually examined more than two dozen buried pipe segments and that: (a) these inspections did not indicate that "poor backfill quality or metal loss caused by external corrosion is a systemic issue at IPEC"; (b) the direct visual inspections "have not revealed evidence of damage to pipe coatings caused by rocks or debris in the backfill"; (c) during the inspection of three pipe segments in October 2012, some small rocks (less than two inches in diameter) were found to be in contact with the outer wrap of the buried pipe, but there was no associated damage; and (d) December 2012 inspections also revealed some rocks in the backfill, but they were not in contact with the pipe. The applicant also stated that if future inspections reveal significant coating damage caused by nonconforming backfill, it will double the inspection sample size. If adverse indications are found in the expanded inspection sample, the size of followup inspections will be based on an extent-of-condition and extent-of-cause analysis (subject to the extent of piping or tanks susceptible to the observed degradation mechanism). In addition, the timing of the inspections will be based on the severity of the degradation and will be commensurate with the consequences of a leak or loss of function from the affected pipe. The applicant further stated that expanded sample inspections will be completed within the 10-year interval in which the original adverse indication was identified.

The staff finds the applicant's response to RAI 3.0.3.1.2 4, Item (2), acceptable because it is consistent with the guidance in the "detection of aging effects" program element of LR-ISG-2011-03, which ensures that an appropriate expansion of inspection is conducted when adverse conditions are detected. The staff's concern described in RAI 3.0.3.1.2.4, Item (2), is resolved.

UFSAR Supplement. As described above, the applicant revised LRA Sections A.2.1.5 and A.3.1.5 to describe the purpose of the CP system. The staff confirmed that these sections are consistent with the guidance in LR-ISG-2011-03.

Conclusion. On the basis of its review of the applicant's response to RAIs 3.0.3.1.2-4 and 3.0.3.1.2-4a, and of the additional information provided by the applicant related to the Buried Piping and Tanks Inspection Program, the staff finds that those program elements for which the applicant claimed consistency with LR-ISG-2011-03 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).

3.0.3.1.9 One-Time Inspection Program

Summary of Technical Information in the Application. The applicant provided additional information related to the One-Time Inspection Program after the issuance of Supplement 1 to the SER. The additional information is discussed below in the “Staff Evaluation” section.

Staff Evaluation. The staff’s evaluation of the applicant’s proposed One-Time Inspection Program is documented in SER Section 3.0.3.1.9. By letter dated March 18, 2013, the applicant revised LRA Section B.1.27, “One-Time Inspection,” to state that the inspection sample size will be at least 20 percent of each material-environment population or a maximum of 25 components, which is consistent with the guidance in AMP XI.M32, “One-Time Inspection,” in Revision 2 of the GALL Report. Previously, the sample size in the One-Time Inspection Program was based on a method that demonstrates a 90-percent confidence that 90 percent of the population does not experience degradation.

The staff finds the applicant’s revised sampling methodology acceptable because it is consistent with the guidance in the GALL Report, Revision 2, for one-time inspections.

The staff noted that the applicant completed the one-time inspections for the One-Time Inspection Program, and an NRC License Renewal Team Inspection included a review of the One-Time Inspection Summary report, the completed inspection tracking matrix, and multiple one-time inspection reports. In an NRC inspection report dated September 19, 2013, the inspectors concluded that the applicant had completed all actions necessary for Commitment No. 19 associated with this program.

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

UFSAR Supplement. There are no changes or updates to this section of the SER.

Conclusion. There are no changes or updates to this section of the SER.

3.0.3.1.13 Selective Leaching Program

Summary of Technical Information in the Application. The applicant provided additional information related to the Selective Leaching Program after the issuance of Supplement 1 to the SER. The additional information is discussed below in the “Staff Evaluation” section.

Staff Evaluation. The staff’s evaluation of the applicant’s proposed Selective Leaching Program is documented in SER Section 3.0.3.1.13. By letter dated March 18, 2013, the applicant revised LRA Section B.1.33, “Selective Leaching,” to state that the inspection sample size will be at least 20 percent of each material-environment population or a maximum of 25 components, which is consistent with the guidance in AMP XI.M33, "Selective Leaching of Materials," in Revision 2 of the GALL Report. Previously, the sample size in the Selective Leaching Program was based on a method that demonstrates a 90-percent confidence that 90 percent of the population does not experience degradation.

The staff noted that the guidance in the GALL Report, Revision 2, includes the revised sampling criteria described by the applicant as well as a recommendation to focus inspections on bounding or lead components most susceptible to aging because of time in service, severity of operating conditions, and lowest design margin. The applicant's revision to the Selective Leaching Program did not include the additional recommendation to inspect components most susceptible to aging. By letter dated June 12, 2013, the staff issued RAI 3.0.3.1.13-1 requesting that the applicant state and justify the criteria that will be used to select the inspection locations in the Selective Leaching Program.

In its response dated July 24, 2013, the applicant stated that inspections focus on the bounding or leading components most susceptible to aging because of time in service, severity of operating conditions, and lowest design margin. The applicant also stated that, where possible, low-flow/stagnant areas, drains, and low points are inspected because these locations are considered the most susceptible to aging effects.

The staff finds the applicant's response acceptable because the applicant's criteria for selecting inspection locations are consistent with those in the updated staff guidance in the GALL Report, Revision 2.

The staff noted that the applicant completed these one-time inspections for the Selective Leaching Program, and an NRC License Renewal Team Inspection included a review of the inspection sampling plan, results, and associated corrective actions. In an inspection report dated September 19, 2013, the inspectors concluded that the applicant had completed all actions necessary for Commitment No. 23 associated with this program.

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

<u>UFSAR Supplement</u>. There are no changes or updates to this section of the SER.

<u>Conclusion</u>. There are no changes or updates to this section of the SER.

3.0.3.2 Programs Consistent with the GALL Report with Exceptions or Enhancements

3.0.3.2.11 Metal-Enclosed Bus Inspection Program

<u>Summary of Technical Information in the Application</u>. LRA Section B.1.20, as modified by letters dated May 6, 2013 and August 16, 2013, describes the Metal-Enclosed Bus (MEB) Inspection Program as an existing program consistent with GALL Report aging management program (AMP) XI.E4, "Metal Enclosed Bus," with enhancements and exceptions.

The applicant stated that the following MEBs are included in the program:

- IP2 and IP3: 6.9 kilovolt (kV) bus between station auxiliary transformers and switchgear buses 1 through 6

- IP3: 6.9 kV bus associated with the gas turbine substation

- IP2: 480 volt (V) bus associated with Substation A
- IP2 and IP3: 480 V bus between emergency diesel generators and switchgear buses 2A, 3A, 5A, and 6A

The applicant stated that the MEB Inspection Program includes the bus and bus connections, the bus enclosure assemblies, and the bus insulation and insulators. In addition, the applicant stated that a sample of the accessible bolted connections will be inspected for loose connections. The applicant also stated that MEB enclosure assemblies will be inspected for loss of material and elastomer degradation under the MEB Inspection Program instead of the Structures Monitoring Program for external surfaces. The applicant further stated that the internal parts of the MEB will be inspected for foreign debris, excessive dust buildup, evidence of moisture intrusion, degradation of bus insulators and insulation. The applicant indicated that the MEB inspection includes visual inspections as well as quantitative measurements such as thermography and connection resistance measurements.

By letter dated May 6, 2013, the applicant made changes to the LRA Sections B.1.20 and A.2.1.19 and to Commitment No. 13 regarding the MEB Inspection Program. Specifically, after further evaluation, the applicant concluded that the IP2 480 V bus associated with Substation A is not required to start the diesel fire pump (DFP). The IP2 480 V bus was originally included within the scope of license renewal as an enhancement to the MEB Inspection Program element "scope of program" because it provides AC power used to charge the DFP batteries. The applicant subsequently determined that the 480 V MEB is not used for starting the DFP but only provides AC power to maintain the charge of the DFP batteries, and it is the DFP batteries that deliver DC power for starting the DFP and provide power to the DFP control system. In addition, the applicant stated that a loss of the 480 V bus initiates an automatic start of the DFP using the DFP batteries. Based on its review, the applicant concluded that the 480 V bus associated with Substation A does not perform a license renewal intended function based on 10 CFR 54.4, "Scope," and can be removed from the scope of the MEB Inspection Program.

Staff Evaluation. The staff's evaluation of the applicant's MEB Inspection Program is documented in SER Section 3.0.3.1.6. After the issuance of the SER, the applicant, by letter dated May 6, 2013, proposed changes to Enhancement 1 of the MEB Inspection Program, as described above.

The staff believed that the MEB associated with 480 V Substation A should remain within the scope of license renewal because it provides AC power to the DFP battery chargers. The DFP batteries start the DFP during fire events. Further, the staff was concerned that a failure of the MEB to supply the DFP battery chargers could result in depletion of the batteries, which would prevent the DFP from performing its license-renewal intended function.

The staff was also concerned that removal of the MEB associated with IP2 480 V Substation A from the MEB Inspection Program might not be in accordance with the requirements of 10 CFR 54.4(a)(3), which requires, in part, that all SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulation for fire protection (10 CFR 50.48, "Fire Protection") be within the scope of license renewal. This is reiterated in Section 2.1.3.1.3 of Revision 1 of NUREG-1800, "Standard

Review Plan for Review of License Renewal Applications for Nuclear Power Plants," which includes the following example:

> ...if an NSR [nonsafety-related] diesel generator is required for safe shutdown under the fire protection plan, the diesel generator and all SSCs specifically relied upon for that generator to comply with NRC regulations shall be included within the scope of license renewal under 10 CFR 54.4(a)(3). Such SSCs may include, but should not be limited to, the cooling water system or systems relied upon for operability, the diesel support pedestal, and any applicable power supply cable specifically relied upon for safe shutdown in the event of a fire.

By letter dated July 17, 2013, the staff issued RAI 3.0.3.2.11-1 requesting that the applicant provide further technical justification as to why the 480 V MEB associated with Substation A is not relied on to demonstrate compliance with NRC regulations.

By letter dated August 16, 2013, the applicant stated the following to justify why 480 V MEB associated with Substation A is not relied on for compliance with 10 CFR 50.48:

> The IP2 diesel fire pump (DFP) serves as backup for the electric fire pumps in the event the electric fire pumps can't provide the pressure required for the water-based fire protection systems. The DFP is designed with a number of features, including auto start capability, to ensure its reliability. The DFP starts automatically upon the following conditions.
>
> 1. Water pressure drop in the IPEC fire main water system
> 2. Loss of electrical supply to the DFP room or to the DFP auxiliaries
>
> Alternating current (AC) power to the DFP room is provided by a 480 VAC feed that utilizes cables and metal-enclosed bus (MEB) from Substation A, which is owned and operated by Consolidated Edison Company. The 480 VAC feed connects to a step-down transformer, which, in turn, is connected to a 120 VAC lighting panel. The lighting panel provides 120 VAC power to the dual battery charger located in the DFP controller panel.
>
> Either of two batteries can start the DFP. The batteries are charged from the engine alternator during DFP operation and by the battery charger during standby conditions. The battery charger automatically maintains the charge on the two batteries. A panel located in the central control room alerts the operators if AC power is lost and if the DFP is running. The diesel fire pump will automatically start as sensed by loss of Feeder 13W84, Substation A, or loss of AC power to the charger.
>
> Thus, by design, in its normal alignment, a failure of the power source to the battery charger will not prevent the diesel fire pump (DFP) from performing its intended function. Loss of AC power to the battery charger actuates an automatic start of the DFP using the energy stored in the batteries. Prior to a loss of the power source to the battery charger, the batteries will be in a charged state capable of starting the DFP. They will not be "depleted and unable to perform their intended function."

> The components that provide power to the battery charger, including the 480 VAC metal-enclosed bus, are not relied on to demonstrate compliance with the Commission's regulation for fire protection (10 CFR 50.48). Therefore, those components do not perform a license renewal intended function as defined in 10 CFR 54.4. As stated above, the batteries, and not the incoming AC power supply, are relied upon to provide power to start the diesel fire pump (DFP) engine upon a valid demand for DFP operation in the event of a fire. After the DFP engine starts, its electrical power needs are met by an engine-driven alternator, which also provides power to maintain the charge on the batteries. In short, because the nonsafety-related AC power source (including feeder, substation, electrical breakers and metal-enclosed bus) is not relied upon to start or run the DFP, its failure will not prevent the DFP from performing its license renewal intended function.
>
> Entergy performs routine testing and monitoring associated with the DFP. On a weekly basis, Entergy checks the battery bank voltage and measures the electrolyte levels to ensure that the individual cells are charged. On a monthly basis, Entergy starts the DFP using the batteries and runs it for at least 30 minutes. As part of the monthly test, Entergy confirms that the operators receive an alarm indicating the engine is running. An alternate battery bank is selected for starting the DFP for each monthly test. In addition, Entergy initiates a loss of power to the battery charger once a year to test the auto-start feature of the DFP. This test also confirms that the operators receive the charger failure alarm. IPEC administrative controls regarding fire system impairments specify the required actions, time frames, and compensatory measures to restore non-functional (impaired) fire protection equipment. Any condition that would challenge the ability of the DFP to automatically start from its normal standby condition (i.e., from the fully charged battery bank(s)) would render the DFP non-functional (impaired) and require corrective actions to restore the DFP in seven days. This provides additional assurance that the batteries are always fully charged and available to perform their intended function in supporting the auto start capability of the DFP.

The staff finds that the DFP serves as backup for the electric fire pumps and is relied on to demonstrate compliance with NRC fire-protection regulations. However, the DFP does not specifically rely on the 480 V bus or battery charger to demonstrate compliance with 10 CFR 50.48 regulations. Further, the applicant's stated weekly DFP and battery-bank operability testing provides an additional means to ensure that the batteries are fully charged. The monthly testing includes starting and running the DFP and verification of battery voltage and electrolyte level. The DFP monthly test uses the batteries and confirms the DFP control room alarms (i.e., the DFP is running). The DFP testing also includes starting the DFP using alternate battery banks for each monthly test. DFP functional tests are performed every 18 months and include verification that the DFP starts on the autostart signal with confirmation of charger failure alarms. Control room alarms indicate when AC power is lost and when the DFP is running. The DFP will automatically start on the loss of 480 V MEB and loss of power to the charger. DFP battery inspections are also performed every 18 months. Therefore, the staff concludes, in accordance with the guidance of SRP-LR Section 2.1.3.1.3, that the IP2 480 V MEB associated with Substation A does not perform a license-renewal intended function and does not require aging management in accordance with 10 CFR 54.4(a)(3). The staff's concern described in RAI 3.0.3.2.11-1 is resolved.

Based on its audit, and review of the applicant's response to RAI 3.0.3.2.11-1, the staff finds that program elements one through six for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.E4, "Metal Enclosed Bus." In addition, the staff reviewed the revised enhancement associated with the "scope of program" program element and finds that the removal of the MEB associated with Substation A from the "scope of program," is appropriate.

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

UFSAR Supplement. By letter dated May 6, 2013, the applicant revised LRA Section A.2.1.19 to remove the IP2 480 V bus associated with Substation A. The change is consistent with the removal of the MEB from the "scope of program" program element in LRA Section B.1.20, "Metal-Enclosed Bus Inspection Program." The applicant also revised Commitment No. 13 to reflect the change in the MEB Inspection Program's license renewal scope.

The staff reviewed the revisions and finds them acceptable because, as described previously, the DFP does not specifically rely on the IP2 480 V bus associated with Substation A to perform a license-renewal intended function; therefore, the 480 V bus associated with Substation A is not required to be within the scope of license renewal under 10 CFR 54.4(a)(3). Therefore, the UFSAR supplement for the MEB Inspection Program is consistent with the corresponding program description in SRP-LR Table 3.0 1.

The staff finds that the information in the UFSAR supplement, as amended by letter dated May 6, 2013, is an adequate summary description of the program.

Conclusion. There are no changes or updates to this section of the SER.

3.0.3.2.15 Structures Monitoring Program

Summary of Technical Information in the Application. The applicant provided additional information related to the Structures Monitoring Program after the issuance of SSER 1 in two separate letters.

In a letter dated May 6, 2013, the applicant stated that in Amendment 5 to the LRA, which included an annual update to the LRA, aging management review results for sump screens, strainers, and flow barriers in the Structures Monitoring Program were revised as a result of a material change from carbon steel to stainless steel. According to the GALL Report, aging management is not required for material made from stainless steel in an air-indoor uncontrolled environment. Therefore, the annual update showed for "sump screens, strainers and flow barriers" that there were no aging effects requiring management (AERM) and no AMP was necessary. Amendment 5 updated tables in Sections 2 and 3 of the LRA, but did not update Appendix A, Appendix B, or the NRC commitment list. Accordingly, in the May 6, 2013, letter, the applicant updated Appendix A, Appendix B, and Commitment No. 25 to eliminate sump screens, strainers, and flow barriers from the scope of the Structures Monitoring Program.

In a letter dated May 14, 2013, the applicant provided an update to additional information that was previously provided in a letter dated November 6, 2008. The applicant stated that as a result of additional research with respect to methods available for detection of leaks in water-filled structures, the action plan, as identified and documented previously in the SER for Unit 2 refueling cavity repair, was changed and a new course of action formulated based on new acoustic monitoring capabilities that have been successful at other facilities. As a result of a change in plans, the Instacote material was not applied to seal the refueling cavity liner walls and floors, nor was any repair work performed in 2010 or 2012. The applicant further stated that this change in plans does not affect the associated Commitment No. 36, which is to perform a one-time inspection and evaluation of the Unit 2 reactor cavity before the period of extended operation. Also, additional core bores will be taken and a sample of the leakage water will be analyzed if the leakage has not stopped before the end of the first 10 years of the period of extended operation.

The applicant performed acoustic monitoring during the spring 2012 outage and identified five areas of leakage. According to the new action plan, the applicant will prepare a modification package to repair the Unit 2 reactor cavity liner and will initiate weld repairs to the Unit 2 cavity liner starting during the 2014 outage. The repairs may occur during multiple refueling outages.

Staff Evaluation. The staff's evaluation of the applicant's proposed Structures Monitoring Program is documented in Section 3.0.3.2.15 of the SER. The staff noted that GALL Report Item III.B1-3.TP-8 indicates that an AMP is not necessary for stainless steel material in an air-indoor environment. Therefore, the staff determined that deletion of the stainless steel sump screens, strainers, and flow barriers located in the indoor air environment from the Structures Monitoring Program, as identified in the May 6, 2013, letter, is acceptable.

Operating Experience. The staff reviewed the proposed changes to the action plan regarding the reactor cavity leakage as described in the May 14, 2013, letter. The staff found the change in action plan for detecting and repairs of reactor cavity liner plate welds acceptable because the applicant has used a new technology (acoustic monitoring) to locate the defective weld locations during the 2012 refueling outage and plans to repair the welds starting during the 2014 refueling outage. Coating the liner plate with Instacote is not a permanent solution to prevent leakage through the defective welds. In addition, this change in plans does not affect Commitment No. 36, which states that the applicant will perform a one-time inspection and evaluation of a sample of potentially affected IP2 refueling cavity before September 28, 2013, to assess the condition of concrete and reinforcing steel in the cavity wall in an area that is susceptible to exposure to borated water leakage. Commitment No. 36 also states that the applicant will take additional core bore samples if the leakage is not stopped and the leakage fluid will be sampled before the end of the first 10 years of the period of extended operation.

UFSAR Supplement. In LRA Sections A.2.1.35 and A.3.1.35, the applicant provided the UFSAR supplement for the Structures Monitoring Program. In a letter dated May 6, 2013, the applicant deleted sump screens, strainers, and flow barriers from the list of structures and components that require aging management in LRA Sections A.2.1.35 and A.3.1.35, and Commitment No. 25. The staff finds this change acceptable because stainless steel sump screens, strainers, and flow barriers do not require aging management.

Conclusion. There are no changes or updates to this section of the SER.

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

3.0.3.3.9 Reactor Vessels Internals

Summary of Technical Information in the Application. LRA Section B.1.42, submitted in Reference 5, describes the RVI Program as a new plant-specific program. The RVI Program manages aging of all RVI components within the scope of license renewal for IP2 and IP3.

According to Tables 3.1.2-2-IP2 and 3.1.2-2-IP3, all RVI components are made from either stainless steels or nickel-based alloys and are exposed to environments consisting of treated borated water, treated borated water > 140 °F, or treated borated water > 482 °F, and the components may also be exposed to neutron fluence. The AERMs are change in dimensions, cracking, loss of material, loss of preload, and reduction of fracture toughness.

The RVI Program is based on MRP-227-A (Ref. 3). The RVI Program relies mainly on inspections conducted using visual, volumetric, and surface examination techniques. The inspection schedules and techniques are consistent with the guidance of MRP-227-A for RVI designed by Westinghouse. However, the RVI Program also credits preventive actions under the "Water Chemistry Control—Primary and Secondary Program." By letter dated September 28, 2011 (Ref. 6), the applicant submitted a detailed RVI Inspection Plan intended to fulfill LRA Commitment No. 30, which required submittal of the detailed RVI program implementing the industry program no later than 2 years before the start of the period of extended operation (which began on September 28, 2013, for IP2). The applicant stated that the September 28, 2011, RVI Inspection Plan is consistent with the staff's safety evaluation (SE) of MRP-227 dated June 22, 2011. The applicant submitted a revised RVI AMP and a revised RVI Inspection Plan as Attachments 1 and 2 to its letter dated February 17, 2012, (Ref. 5); the applicant stated that these reflect the issuance of MRP-227-A. The February 17, 2012, RVI AMP revised the RVI AMP contained in LRA Amendment 9 dated July 14, 2010, and the RVI Inspection Plan replaced the September 28, 2011, RVI Inspection Plan; therefore, the staff based its review on the February 17, 2012, submittal. The staff's evaluation of the RVI Inspection Plan is contained in Section 3.0.3.3.10 of this SER supplement.

<u>Staff Evaluation</u>. Typically, for plant–specific AMPs, the staff reviews program elements one through six of the applicant's program against the acceptance criteria for the corresponding elements as stated in Section A.1.2.3 of Revision 1 of the SRP-LR. The staff's review generally focuses on how the applicant's program manages aging effects through the effective incorporation of these program elements.

After the submittal of MRP-227 and before the issuance of the safety evaluation (SE) on MRP-227, Revision 2 of the GALL Report was issued, providing new AMR line items and aging management guidance in AMP XI.M16A, "PWR Vessel Internals." This AMP was based on staff expectations for the guidance to be provided in MRP-227-A. Because Revision 2 of the GALL Report was published before the issuance of the final SE for MRP-227-A, the staff published LR-ISG-2011-04, "Updated Aging Management Criteria for Reactor Vessel Internal Components for Pressurized Water Reactors" (Ref. 7), which modifies the guidance of AMP XI.M16A to be consistent with MRP-227-A.

Therefore, because LR-ISG-2011-04 represents the most recent staff guidance for RVI programs, the staff used LR-ISG-2011-04 as guidance in performing its review of the elements of the RVI AMP rather than relying on the generic guidance of SRP-LR, Revision 1, Section A.1.2.3. The staff's review of the "corrective actions," "confirmation process," and "administrative controls" programs elements are documented in Section 3.0.4 of Vol. 2 of the SER (Ref. 8). However, the applicant included some information for these elements specific to the RVI AMP, so the staff evaluation of the information specific to the RVI AMP is included in the appropriate subsection of this SER supplement.

<u>*Scope of Program*</u>. LRA Section B.1.42 states that the program scope is based on the MRP-227-A guidelines and that the categorization of components for Westinghouse pressurized water reactors (PWRs) as presented in MRP-227-A applies to the IP2 and IP3 vessel internals.

The applicant also indicated that the component inspections identified in Tables 4-3 and 4-6 of MRP-227-A for Primary and Expansion group components define the scope of the IP2 and IP3 RVI Program inspections. Components in Table 4-9 of MRP-227-A subject to aging management by existing programs are also included in the program scope. RVI components that are not included in Table 4-3, 4-6, or 4-9 are considered to be within the program scope but require no specific inspections.

The staff reviewed the applicant's description of the "scope of program" program element against the criteria of Section XI.M16A of LR-ISG-2011-04, which recommend that the components to be inspected, inspection methods, and inspection schedules be based on MRP-227-A. LR-ISG-2011-04 also notes that Section XI, "Inservice Inspection of Nuclear Power Plant Components," of the ASME *Boiler and Pressure Vessel Code* ("ASME Code") includes inspection requirements for PWR removable core support structures in Table IWB-2500-1, Examination Category B-N-3, which are in addition to any inspections that are implemented in accordance with MRP-227-A.

The staff reviewed Tables 3.1.2-2-IP2 and 3.1.2-2-IP3 in LRA Amendment 9 (Ref. (1) to confirm that the components within the scope of the program are consistent with MRP-227-A. The staff notes that the component descriptions in the AMR table are different in some cases from the terminology used in MRP-227-A. However, Table 5-1 of the RVI Inspection Plan (Ref. 5) provides cross-references of the component names from LRA Amendment 9 to the component names from MRP-227-A's Primary, Expansion, and Existing Programs components for RVI designed by Westinghouse. The staff's review of Table 5-1 of the RVI Inspection Plan confirms that all of the components in these categories from MRP-227-A have an equivalent in the AMR tables of LRA Amendment 9. In addition, Tables 5-2, 5-3, and 5-4 of the RVI Inspection Plan are essentially identical to Tables 4-3, 4-6, and 4-9 of MRP-227-A with respect to the components to be inspected, inspection methods, and inspection schedules for RVI components in the Primary, Expansion, and Existing Programs inspection categories. Because the AMR line items in Table IV.B2, "Reactor Vessel, Internals, and Reactor Coolant System—Reactor Vessel Internals (PWR)—Westinghouse," in LR-ISG-2011-04 are consistent with MRP 227-A, conformance of the AMR tables to MRP-227-A means that the components within the scope of the program are also consistent with LR-ISG-2011-04.

LRA Section B.1.42 also confirms that the components to be inspected and the nondestructive examination (NDE) methods are consistent with MRP-227-A.

Based on its review of the LRA and Reference 5, the staff finds that the scope of the IP2 and IP3 RVI Program meets the criteria of Section X1.M16A of LR-ISG-2011-04 and is therefore acceptable.

<u>*Preventive Actions*</u>. LRA Section B.1.42 states that the RVI Program is a condition monitoring program that does not include preventive actions. However, the applicant credits the Water Chemistry Control—Primary and Secondary Program with minimizing the potential for loss of material, stress corrosion cracking (SCC), primary water stress corrosion cracking (PWSCC), and irradiation-assisted stress corrosion cracking (IASCC). The applicant also noted that both IP units implemented a low leakage core loading pattern within the first 30 years of operation and that there have been no design changes to the RVI beyond those identified in industry guidance or recommended by Westinghouse.

The staff reviewed the applicant's description of the "preventive actions" program element against the criteria of Section XI.M16A of LR-ISG-2011-04, which states that the MRP-227-A relies on PWR water chemistry control to prevent or mitigate aging effects that can be induced by corrosive aging mechanisms (e.g., loss of material induced by general corrosion, pitting corrosion, crevice corrosion, or stress corrosion cracking or any of its forms (SCC, PWSCC, or IASCC)). Section XI.M16A of LR-ISG-2011-04 further states that reactor coolant water chemistry is monitored and maintained in accordance with the Water Chemistry Program, as described in GALL AMP XI.M2, “Water Chemistry.”

LRA Section B.1.41 described the existing Water Chemistry Control—Primary and Secondary Program as consistent with Chapter XI.M2, “Water Chemistry,” of Revision 1 of the GALL Report, with enhancement. The staff’s evaluation of the Water Chemistry Control Program is documented in Section 3.0.3.2.17 of the SER (Ref. 8), in which the staff agreed with the applicant’s assertion that the program was consistent with the GALL Report, Revision 1.

The staff finds the applicant’s “preventive actions” program element to be adequate because it meets the criteria of Section XI.M16A of LR-ISG-2011-04 for this program element that reactor coolant water chemistry be monitored and maintained in accordance with the Water Chemistry Program, which (as noted above) is consistent (with enhancement) with the corresponding GALL program.

Based on its review of the LRA, the staff finds that the criteria for the preventive actions of Section XI.M16A of LR-ISG-2011-04 are met; therefore, this program element is acceptable.

Parameters Monitored/Inspected. LRA Section B.1.4.2 states that the RVI Program will monitor the effects of aging on the intended functions of the internals through periodic and conditional examinations and other aging management methods, as required. LRA Section B.1.4.2 states that the component inspections identified in MRP-227-A Tables 4-3 and 4-6 (for Primary and Expansion group components respectively) set forth the parameters monitored by the Indian Point Energy Center (IPEC) RVI Program inspections; it further states that the program will use NDE techniques to detect loss of material through wear; identify changes in dimension due to void swelling and irradiation growth, distortion, or deflection distortion of components; and locate cracks induced by SCC, PWSCC, IASCC, or fatigue/cyclical loading. LRA Section B.1.42 also indicated the following with regard to specific NDE techniques used to detect specific aging effects:

- Loss of preload, due to thermal and irradiation-enhanced stress relaxation or creep, is indirectly monitored by inspecting for gross surface conditions that may indicate loosening in applicable bolted, fastened, keyed, or pinned connections.

- The reduction of fracture toughness, induced by either thermal aging (thermal embrittlement (TE)) or neutron irradiation embrittlement (IE), is indirectly monitored by using visual or volumetric examination techniques to monitor for cracking in the components and by applying applicable reduced fracture-toughness properties in flaw evaluations where this is warranted.

- Visual examinations (VT-3) will be used to detect wear and detect distortion or cracking through indications such as gaps or displacement along component joints and broken or damaged bolt locking systems.

- Direct measurements of spring height will be used to detect distortion of the internals hold down spring.

- Enhanced visual examinations (EVT-1) will be used to detect broken components and crack-like surface flaws of components and welds.

- Volumetric (ultrasonic) examinations will be used to locate cracking of bolting.

The staff reviewed the applicant's "parameters monitored/inspected" program element against the criteria of LR-ISG-2011-04 Section XI.M16A, which recommends that for plants with RVI of Westinghouse design, the RVI Program should meet the parameters monitored/inspected criteria consistent with the applicable tables in Section 4, "Aging Management Requirements," of MRP-227-A. The staff verified that the parameters monitored and inspected and the methods identified by the applicant are consistent with the parameters monitored and the inspection methods from MRP-227-A Tables 4-3 and 4-6. In addition, Tables 5-2, 5-3, and 5-4 of the applicant's RVI Inspection Plan provide information for the components in the three inspection categories (Primary, Expansion, and Existing Programs), which include the applicability (e.g., to IP2 and/or IP3), aging effects to be looked for, linked components for Primary and Expansion components, and the associated examination techniques, examination frequencies, and required examination coverage. The staff notes that these tables are essentially identical to Tables 4-3, 4-6, and 4-9 of MRP-227-A.

Based on its review of the LRA and Reference 5, the staff finds the applicant's description of the "parameters monitored/inspected" program element to be acceptable because it is consistent with the criteria of LR-ISG-2011-04 Section XI.M16A, which cites the guidance of MRP-227-A.

Detection of Aging Effects. LRA Section B.1.42 states that the RVI Program will detect cracking, loss of material, reduction of fracture toughness, loss of preload, and dimensional changes (distortion) of vessel internals components in accordance with the specific provisions of MRP-227-A. LRA Section B.1.42 further states that the NDE systems (i.e., the combinations of equipment, procedure, and personnel) used to detect these aging effects will be qualified in accordance with MRP-228, "Materials Reliability Program: Inspection Standard for PWR Internals," and that the RVI Program will conduct inspections of Primary group components as delineated in MRP-227-A Table 4-3. Additionally, LRA Section B.1.42 states that indications from EVT-1 or UT inspections may result in additional inspections of Expansion group components, as determined by Expansion criteria delineated in MRP-227-A Table 5-3. LRA Section B.1.42 further states that the relationships between Primary group component inspection findings and additional inspections of Expansion group components are as described in MRP-227-A Table 4-6.

Based on its review of the RVI Inspection Plan (Ref. 5), the staff found that the information in Table 5-2 for each Primary inspection category item and Table 5-3 for each Expansion inspection category item, including the effect/mechanism inspected for, the examination method/frequency, and the required examination coverage, is consistent with MRP-227-A Table 4-3 (for Primary inspection category items) and Table 4-6 (for Expansion inspection category items).

With respect to detection of aging effects, LR-ISG-2011-04, Chapter X1.M16A states, in part, that the inspection methods are defined and established in Section 4 of MRP-227-A and that standards for implementing the inspection methods are defined and established in MRP-228. LR-ISG-2011-04 also describes the inspection methods to be used for detection of various aging mechanisms, all of which are consistent with MRP-227-A. LR-ISG-2011-04 states that inspection coverages for Primary and Expansion RVI components are implemented consistent with Sections 3.3.1 and 3.3.2 of Revision 1 of the NRC's SE for MRP-227. However, the staff notes that these minimum inspection coverage requirements were incorporated in MRP-227-A as required by Condition 4 of Revision 1 of the staff's final SE for MRP-227. Therefore, consistency with MRP-227-A Section 4 will ensure that this recommendation is met.

For the Primary and Expansion group components, the staff finds that the applicant's program will meet the criteria of LR-ISG-2011-04 Section X1.M16A because the applicant's program will conduct inspections of these components in accordance with MRP-227-A Tables 4-3 and 4-6. In addition, based on the staff's review of Tables 5-2 and 5-3 from the RVI Inspection Plan (Ref. 5), the item, aging effect/mechanism, examination methods, examination coverage, and schedules (including reexamination frequency) described are consistent with the corresponding information for Primary and Expansion inspection category components in Tables 4-3 and 4-6 of MRP-227-A, with no additional plant-specific components. The staff found, based on its review of the applicant's response to Applicant/Licensee Action Item (A/LAI) 2 from the final SE for MRP-227, Revision 0, detailed in Section 3.0.3.3.9.3, that no components required inspection in the Primary or Expansion categories other than those recommended in MRP-227-A. Further, because the applicant's RVI Program states that the NDE systems (i.e., the combinations of equipment, procedure, and personnel) used to detect these aging effects will be qualified in accordance with MRP-228, this criterion of LR-ISG-2011-04 Section XI.M16A is met.

Based on its review of the LRA and Reference 5, the staff finds the applicant's description of the "detection of aging effects" program element to be acceptable because the components to be inspected as Primary and Expansion components, the NDE methods, the schedule, and the qualification of NDE systems are consistent with MRP-227-A and MRP-228, as recommended in LR-ISG-2011-04 Section X1.M16A.

Monitoring and Trending. LR-ISG-2011-04 Section XI.M16A recommends using the methods of MRP-227 Section 6 for monitoring, recording, evaluating, and trending the data from the program inspection results. MRP-227 Section 6 includes recommendations for flaw depth sizing and for crack growth determinations as well as for performing applicable limit load, linear elastic, and elastic-plastic fracture analyses of relevant flaw indications. LR-ISG-2011-04 Section XI.M16A also states that "examination and re-examinations that are implemented in accordance with MRP-227-A, together with the criteria of MRP-228 for inspection methodologies, inspection procedures, and qualification of inspection personnel, provide timely detection, reporting, and implementation of corrective actions for the aging effects and mechanisms managed by the program."

Section 7 of the AMP, "Corrective Actions," states that any detected condition that fails to meet the examination acceptance criteria must be processed through the corrective action program. Section 7 further states that (1) example methods for analytical disposition of unacceptable conditions are discussed or cited in Section 6 of MRP-227-A and (2) the evaluation methods include recommendations for flaw depth sizing and for crack growth determinations as well for performing applicable limit load, linear elastic, and elastic-plastic fracture analyses of relevant flaw indications. Section 7 further states that these methods or other NRC-approved evaluation methods may be used. However, in the staff's final SE for MRP-227, Revision 0 (Ref. 9), the staff noted that in an RAI response, EPRI stated that topical report WCAP-17096-NP, "Reactor Internals Acceptance Criteria Methodology and Data Requirements" (Ref. 10), is the document that will be used as the framework to develop those generic and plant-specific evaluations triggered by findings in the RVI examinations, and also that the staff is currently reviewing WCAP-17096-NP, Revision 2. In RAI 4, the staff therefore requested that the applicant clarify whether the IPEC RVI Program will use the guidance of WCAP-17096-NP, Revision 2, for evaluating the acceptability of relevant conditions found by the inspection conducted under the

RVI Inspection Plan. In its response to RAI 4 by letter dated June 14, 2012 (Ref. 4), the applicant indicated that it plans to use the guidance of WCAP-17096-NP, Revision 2, for evaluating the acceptability of relevant conditions found by the inspections conducted under the RVI Inspection Plan. RAI 4 is, therefore, resolved.

The applicant stated in the "Detection of Aging Effects" section of the RVI Program that "[t]he NDE system (i.e., the combinations of equipment, procedure, and personnel) used to detect [the relevant] aging effects will be qualified in accordance with MRP-228." Therefore, the staff finds that this criterion of LR-ISG-2011-04 Section XI.M16A is met.

LR-ISG-2011-04 also states that the program applies applicable fracture toughness properties, including reductions for thermal aging or neutron embrittlement, to the flaw evaluations of the components in cases in which cracking is detected in a RVI component and is extensive enough to warrant a supplemental flaw-growth or flaw-tolerance evaluation. The staff notes that MRP-227-A Section 6 provides guidance on the fracture toughness properties to be used. Therefore, the staff finds that the applicant's AMP meets this criterion because it will follow the recommendations of MRP-227-A Section 6.

LR-ISG-2011-04 also states that (1) "[f]or singly represented components, the program includes criteria to evaluate the aging effects in the inaccessible portions of the components and the resulting impact(s) on the intended function(s) of the components," and (2) "[f]or redundant components (such as redundant bolts, screws, pins, keys, or fasteners, some of which are accessible to inspection and some of which are not accessible to inspection), the program includes criteria to evaluate the aging effects in the population of components that are inaccessible to the applicable inspection technique and the resulting impact on the intended function(s) of the assembly containing the components." In the SE for MRP-227, the staff found that MRP-227 adequately addresses inaccessible locations provided that Condition 4 of the SE is met, which required that the percentage of the total (inaccessible plus accessible) area or population that must be inspected is 75 percent. This recommendation is implemented in Primary and Expansion category component inspections specified in Tables 5-2 and 5-3 of the RVI Inspection Plan (Ref. 5). Because the applicant's AMP will implement the inspection coverage and sampling recommendation, which are incorporated in the tables in Section 4.0 of MRP-227-A, the staff finds that this recommendation of LR-ISG-2011-04 is met.

Based on its review of the LRA, the staff finds the applicant's description of the "monitoring and trending" program element acceptable because the AMP is consistent with the criteria of LR-ISG-2011-04 Section XI.M16A for this element.

Acceptance Criteria. LRA Section B.1.42, in the "Acceptance Criteria," section, states that the RVI Program acceptance criteria are from Section 5 of MRP-227-A. LRA Section B.1.42 further states that Table 5-3 and Sections 5-1 through 5-3 of MRP-227-A provide the acceptance criteria for inspections of the Primary and Expansion group components and that the criteria for expanding the examinations from the Primary group components to include the Expansion group components are also delineated in MRP-227-A, Table 5-3. Finally, LRA Section B.1.42 states that the examination acceptance criteria include (i) specific, descriptive, relevant conditions for the visual (VT-3) examinations; (ii) requirements for recording and dispositioning surface breaking indications that are detected and sized for length by the enhanced visual (EVT-1) examinations; (iii) requirements for system-level assessment of bolted assemblies with unacceptable volumetric UT examination indications that exceed specified limits, and (iv) requirements for fit up limits on physical measurements of the hold-down springs.

The staff compared the applicant's proposed acceptance criteria to the guidance of LR-ISG-2011-04 Section XI.M16A, which recommends that Section 5 of MRP-227-A (specifically Table 5-3 for Westinghouse-designed RVI) provides the specific examination and flaw evaluation acceptance criteria for the Primary and Expansion Component examinations. The staff finds the applicant's reference to Section 5 and Table 5-3 of MRP-227-A to be acceptable because it meets the criteria of LR-ISG-2011-04.

For baffle-former bolts, MRP-227-A Table 5-3 states that the examination acceptance criteria for the UT shall be established as part of the examination's technical justification (TJ). MRP-228 provides additional guidance on preparation of TJs. However, the IP2 and IP3 RVI Program does not indicate whether a TJ has been or will be developed for the baffle-former bolts. Therefore, in RAI 5, the staff requested that the applicant submit a TJ for the IP2 and IP3 baffle-former bolts or discuss the plans and schedule for development of the TJ and submission to the NRC.

In its response to RAI 5 by letter dated June 14, 2012 (Ref. 4), the applicant indicated that it had not developed the TJ yet because the MRP-227-A inspection requirements for baffle-former bolts specify that the inspections must be completed by 35 EFPY (effective full-power years), which is expected to be reached in 2019 for IP2 and in 2021 for IP3. The applicant indicated that the TJ would be completed by 6 months before the inspection. The staff found the applicant's response to RAI 5 acceptable because the inspection schedule is consistent with MRP-227-A and it clarified that the TJ will be developed before the inspection. In addition, the staff determined that it does not need to review the TJ to make a safety finding on the applicant's AMP because (1) MRP-227-A and the staff's final SE for MRP-227, Revision 0 do not specify that TJs must be submitted for staff review and approval; (2) UT examinations of baffle-former bolts have been performed since the late 1990's, thus, there is reasonable assurance that these examinations can be implemented effectively at IP2 and IP3; and (3) finalizing the TJ closer to the date of the inspection will allow for the latest UT technology and lessons learned from previous baffle-former bolt examinations to be incorporated. The staff's concern in RAI 5 is therefore resolved.

Based on its review of the LRA, the staff finds the applicant's description of the "acceptance criteria" program element acceptable because the acceptance criteria will be in accordance with the MRP-227-A recommendations, thus meeting the guidance of LR-ISG-2011-04 Section X1.M16A.

Corrective Actions. The applicant's description of the corrective actions attribute of the program includes the following elements:

- Conditions adverse to quality such as failures, malfunctions, deviations, defective material and equipment, and nonconformances are promptly identified and corrected.

- In the case of significant conditions adverse to quality, measures are implemented to ensure that the cause of the nonconformance is determined and that corrective action is taken to preclude recurrence.

- In addition, the cause of the significant condition adverse to quality and the corrective action implemented is documented and reported to appropriate levels of management.

- The Entergy Quality Assurance Program (under Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to 10 CFR Part 50, "Domestic

Licensing of Production and Utilization Facilities"), including relevant corrective action controls, applies to the RVI Program. Any detected condition that fails to meet the examination acceptance criteria must be processed through the corrective action program.

- The evaluation methods include recommendations for flaw depth sizing and for crack growth determinations as well for performing applicable limit load, linear elastic, and elastic-plastic fracture analyses of relevant flaw indications.

- Example methods for analytical disposition of unacceptable conditions in Section 6 of MRP-227 or other demonstrated and verified alternative methods may be used.

- The alternative of component repair and replacement of PWR internals is subject to the applicable requirements of Section XI of the ASME Code.

The staff reviewed the applicant's proposed corrective actions element for the RVI Program and finds that it meets the criteria of LR-ISG-2011-04 Section XI.M16A. In particular, LR-ISG 2011-04 recommends processing any unacceptable conditions through the plant's corrective action program. The applicant's description of the corrective actions attribute includes provisions to use the methodologies in Section 6 of MRP-227-A or other acceptable alternatives to analytically disposition unacceptable conditions, which is consistent with LR-ISG-2011-04. In RAI 4, the staff requested additional information on the applicant's use of the methodology of WCAP-17096-NP for analytically dispositioning unacceptable conditions (see evaluations of the "Monitoring and Trending" and "Acceptance Criteria" AMP elements for the staff's evaluation of this issue). The applicant also indicated that if component repair or replacement are performed, these activities will meet the applicable requirements of Section XI of the ASME Code, which is also consistent with the criteria of LR-ISG-2011-04. The staff therefore finds the corrective actions element of the applicant's program to be acceptable. LR-ISG-2011-04 Section XI.M16A also allows the option of using previously approved alternative corrective action bases. However, the applicant did not cite any such bases.

Additionally, the staff's review and acceptance of the IPEC generic corrective actions process is documented in Section 3.0.4 of THE SER (Ref. 8).

Based on its review of the LRA, the staff finds the applicant's "corrective actions" program element acceptable because the description is consistent with the criteria of LR-ISG-2011-04 Section XI.M16A for this program element.

Confirmation Process. The applicant referred to Section B.0.3 of the LRA for a description of this attribute. This attribute is generic for all the IPEC AMPs.

The staff's review and acceptance of the applicant's confirmation process is documented in Section 3.0.4 of NUREG-1930 (Ref. 8).

Regarding the Confirmation Process, LR-ISG-2011-04 Section XI.M16A states that site quality assurance procedures, review and approval processes, and administrative controls are implemented in accordance with the recommendations of Nuclear Energy Institute (NEI) 03-08, "Guidelines for the Management of Materials Issues" (Ref. 11), and the requirements of Appendix B to 10 CFR Part 50 or their equivalent as applicable. LR-ISG-2011-04 Section XI.M16A further states that the implementation of the guidance in MRP-227-A, in conjunction with NEI 03-08 and other guidance documents, reports, or methodologies cited in this AMP, provides an acceptable level of quality and an acceptable basis for confirming the quality of inspections, flaw evaluations, and corrective actions.

The RVI AMP states in the program description that IPEC will implement and maintain the RVI Program in accordance with the guidance in Addendum A, “RCS Materials Degradation Management Program Guidelines,” to NEI 03-08 and that any deviations from mandatory, needed, or good-practice implementation activities established in MRP-227-A or MRP-228 will be managed in accordance with the NEI 03-08 implementation protocol.

Because the attributes of the applicant’s confirmation process (including conformance to Appendix B to 10 CFR 50) were approved in the SER (Ref. 8) and the AMP also meets the guidance of NEI 03-08, the staff finds that the applicant’s confirmation process is consistent with LR-ISG-2011-04 Section XI.M16A and is therefore acceptable.

Administrative Controls. The applicant referred to Section B.0.3 of the LRA for a description of this attribute. This attribute is generic for all of the IPEC AMPs.

The staff’s review and acceptance of the applicant’s administrative controls attribute is documented in Section 3.0.4 of the SER (Ref. 8). This attribute is not changed by this amendment. Therefore, the staff considers the administrative controls as applied to the RVI Program to be acceptable.

LR-ISG-2011-04 Section XI.M16A states that the administrative controls for these types of programs, including their implementing procedures and review and approval processes, are implemented in accordance with the recommended industry guidelines and criteria in NEI 03-08, and are under existing site 10 CFR 50 Appendix B Quality Assurance Programs, or their equivalent, as applicable. LR-ISG-2011-04 Section XI.M16A further states that the evaluation in Section 3.5 of the NRC's SE, Revision 1, of MRP-227 provides the basis for endorsing NEI 03-08, and that this includes endorsement of the criteria in NEI 03-08 for notifying the NRC of any deviation from the inspection and evaluation (I&E) methodology in MRP-227-A and for justifying the deviation no later than 45 days after its approval by a licensee executive.

The RVI AMP states in the program description that IPEC will implement and maintain the RVI Program in accordance with the guidance in Addendum A to NEI 03-08 and that any deviations from mandatory, needed, or good practice implementation activities established in MRP-227-A or MRP-228 will be managed in accordance with the NEI 03-08 implementation protocol.

Conformance to the NEI 03-08 implementation protocol, as stated in the RVI AMP Program Description, will ensure that the criteria of LR-ISG-2011-04 Section XI.M16A regarding administrative controls are met, including notification of the NRC of any deviations from MRP-227-A guidance.

Because the staff concluded in the SER that the applicant’s administrative controls are in accordance with Appendix G, “Fracture Toughness Requirements,” to 10 CFR 50 and that the RVI AMP meets the NEI 03-08 implementation requirements, including notification of the NRC of deviations from MRP-227-A, the staff finds that the administrative controls element of the RVI AMP is consistent with LR-ISG-2011-04 Section XI.M16A and is therefore acceptable.

Operating Experience. LRA Section B.1.42 summarizes operating experience related to the RVI Program. Because this is a new program and IPEC has not implemented any RVI inspections using the guidance of MRP-227-A, there is no plant-specific operating experience.

The applicant discussed the applicable industry experience related to RVI, particularly the experience related to baffle-former bolt cracking. The applicant indicated that it has appropriately responded to industry operating experience for RVI and cited as an example the replacement of guide-tube support pins (split pins) in both units. The applicant also indicated that it recognizes cracking of baffle-former bolts as a potential issue for the IPEC units and has been monitoring industry developments and recommendations regarding these components. The applicant also discussed the experience at IPEC with implementing the required ASME Section XI inspections of RVI, which consist of visual VT-3 inspections, in which it has found no degradation. The applicant also stated that as implemented, this program will account for applicable future operating experience during the period of extended operation.

In the “Monitoring and Trending” section, LRA Section B.1.42 states that records of inspection results are maintained in a way that allows comparison with subsequent inspection results. LRA Section B.1.42 additionally states that IPEC will share inspection results with the industry in accordance with the good-practice recommendations of MRP-227-A and that IPEC will provide a summary report of all inspections and monitoring, items requiring evaluation, and new repairs to the MRP Program Manager. The IPEC-specific results will be incorporated in an overall industry report that will track industry progress and will aid in evaluation of potentially significant issues, identification of fleet trends, and determination of any needed revisions to the MRP-227-A guidelines.

LR-ISG-2011-04 Section XI.M16A states, with respect to operating experience, that the review and assessment of relevant operating experience for its impacts on the program, including implementing procedures, are governed by NEI 03-08 and Appendix A of MRP-227-A, and that, consistent with MRP-227-A, the reporting of inspection results and operating experience is treated as a “Needed” category item under the implementation of NEI 03-08. LR-ISG-2011-04 Section XI.M16A further states that the program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience, as discussed in Appendix B of the GALL Report, which is documented in LR-ISG-2011-05, “Ongoing Review of Operating Experience.”

The information from Section 5 of the AMP is consistent with the recommendation in Chapter XI.M16A of Revision 2 of the GALL Report for participation in the industry’s monitoring and trending effort with respect to operating experience (OE). In addition, in the staff’s evaluation of the RVI Inspection Plan in Section 3.0.3.3.10, the staff found that IPEC’s RVI Program complies with the reporting requirements of MRP-227-A Section 7, which are consistent with NEI 03-08.

MRP-227-A, Appendix A summarizes industry operating experience regarding age-related degradation of RVI components through 2010, including a failure of clevis insert bolts at one Westinghouse-design reactor in 2010. Subsequent to the issuance of MRP-227-A, new information became available. Specifically, an apparent cause analysis by the affected licensee indicated that the most likely cause of the bolt failures is PWSCC. Therefore, in RAI 17, the staff requested that the applicant address this recent operating experience, and either modify its inspection requirement for the IP2 and IP3 clevis insert bolts as necessary to manage the effects of PWSCC or provide a technical justification for the adequacy of the existing inspection requirements. In its September 27, 2013, response to RAI 17 (Ref. 12), the applicant provided a technical justification for the adequacy of the existing inspection requirements. The applicant cited Westinghouse InfoGram IG-10-1, “Reactor Internals Lower Radial Support Clevis Insert

Cap Screw Degradation," dated March 31, 2010 (Ref. 13), in support of its response. The key points of the applicant's response are summarized as follows:

- The main design function of the lower radial support system (LRSS), of which the clevis insert bolts (capscrews) are a part, is the prevention of tangential or rotational motion of the lower internals assembly while permitting axial displacement and differential radial expansion. These supports are designed to prevent excessive tangential displacement of the lower internals during seismic events and loss-of-coolant accident (LOCA) conditions and also to limit displacements and misalignments in order to avoid overstressing the core barrel and to ensure that the control rods can be freely inserted.

- The main aging effect of concern is wear due to flow-induced vibration. Failure of capscrews could result in increased wear, which would occur over several cycles (as well as during seismic events and LOCA conditions) and does not impact the function of the LRSS. This is based on the OE at the plant that had experienced clevis insert bolt failures.

- There is a high degree of redundancy in the LRSS. Both IP2 and IP3 have six radial supports spaced at 60-degree intervals around the circumference of the reactor pressure vessel (RPV). Because of the small clearances involved, it is unlikely that complete disengagement of the clevis inserts would occur. If one clevis insert became nonfunctional, the other lower radial supports are capable of resisting all of the internal and external asymmetric loads.

- Crack detection before bolt failure is not required because of inherent design redundancy.

- Westinghouse performed an evaluation of the potential for creation of loose parts (and damage from loose parts) caused by clevis insert bolt degradation and concluded that no significant degradation of mechanical components is expected as a result of potential loose parts in the primary system. This is because separated capscrew heads will remain captured in the clevis insert counterbores. Although lock bars experienced wear-related degradation at the plant with the bolt failures, the potential for damage from loose lock bars is minimal.

- The visual inspections performed using video cameras during each ten-year interval under ASME Code Section XI are capable of identifying wear or dislodged components of the clevis insert capscrews or dowel pins at any location, if they exist.

- The Alloy X-750 material used in the IP2 and IP3 clevis insert bolts is not in the most susceptible heat-treatment condition for PWSCC.

Although the applicant stated in its response to RAI 17 that the ASME Code Section XI video camera inspections are capable of identifying wear or dislodged components of the clevis insert capscrews or dowel pins, the staff requested additional clarification in RAI 17-A regarding the ASME Code Section XI inspection of the clevis inserts in order to ensure that the type of degradation documented in Westinghouse InfoGram IG-10-1 would be reliably detected at IP2 and IP3.

In its June 9, 2014, response to RAI 17-A (Ref. 14), the applicant stated that the clevis insert bolts at IP2 and IP3 are inspected as part of the Category B-N-2 Item Number B13.60

inspections. The response also states that at IPEC, the ASME Code Section XI examination of the clevis inserts directly views all the clevis insert bolt heads, dowel pins, and locking devices for each clevis insert and, therefore, Entergy's ASME Code Section XI inservice inspection (ISI) program does not require modification. Also, the applicant stated that the most recent ASME Code Section XI inspection of the clevis insert bolts was conducted at IP2 in 2006 with no recordable indications and at IP3 in 2009 with no recordable indications.

The staff evaluated the information provided by the applicant in response to RAI 17 and RAI 17-A. The staff also considered the latest information related to clevis insert bolt OE presented by the Pressurized Water Reactor Owners Group (PWROG) during the June 2014 "Industry and NRC Coordination Meeting Materials Program Technical Exchange" (Ref. 15). The PWROG presentation indicated that 29 of the 48 bolts at a U.S. nuclear power plant were either partially or completely fractured, while only 7 of these failed bolts were detected visually. The PWROG information also indicated that visual inspections may not detect every failed bolt. However, the PWROG noted that bolt failure is primarily a commercial (economic) rather than a safety issue, that there is no immediate safety issue, and that visual inspection of wear surfaces and general condition will provide the appropriate level of aging management without the need for bolt inspections. The PWROG plans to issue a technical bulletin that will recommend (a) performing VT-3 examination to look for specific conditions of the interfacing surfaces of the radial keys, clevis inserts, and bolt heads that would indicate the functional performance of the LRSS and (b) managing bolt degradation to reduce economic risk.

The OE also supports the applicant's position that crack detection before bolt failure is not needed because the problem was detected by means of complete failures of several bolts out of the population while the overall design function of the LRSS was not compromised. A higher-resolution visual examination than the VT-3 visual examination currently performed, consisting of an EVT-1 enhanced visual examination, would not be more effective than the VT-3 examination at detecting cracked bolts before they completely fail, because the cracking occurred in the bolt shank-to-head region, which is hidden. The only other inspection option is UT inspection. Requiring UT for the clevis insert bolts, which would probably involve significant tooling and procedure development, is not warranted at this time based on the limited number of failures of these bolts and the high degree of redundancy in the LRSS. Because the applicant confirmed that its ASME Code Section XI VT-3 examination of the clevis inserts directly views the bolt heads, dowel pins, and locking devices, the ASME Code Section XI examination should detect failed bolts. Although not all failed or cracked bolts were detected visually at the plant that experienced the clevis insert bolt failures, enough failed bolts were detected to alert the licensee that there was a problem before the function of the LRSS could be compromised. Therefore, the staff finds that the licensee's VT-3 visual examination of the clevis insert bolts is adequate to manage aging of these bolts.

Based on its evaluation of the applicant's responses to RAIs 17 and 17-A, the staff finds that the applicant has provided an adequate technical justification for maintaining the current MRP-227-A inspection requirements for the clevis insert bolts. The staff's concerns in RAI 17 and RAI 17-A are thus resolved.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its review of the LRA as modified by Reference 5, the staff finds the applicant's "operating experience" program element to be acceptable because it (a) meets the criteria of

LR-ISG-2011-04 Section XI.M16A by providing for a systematic and ongoing review of plant-specific and industry operating experience and (b) conforms to the guidance of NEI 03-08 with regard to reporting of operating experience. Further, the staff finds that the applicant has appropriately responded to past operating experience such as that related to SCC of split pins and the recent OE related to clevis insert bolts.

UFSAR Supplement. LRA Sections A.2.1.41 and A.3.1.41, as amended in Reference 5, provide the UFSAR supplements for the RVI Program.

The staff reviewed this UFSAR supplement description of the program against the description for AMP XI.M16A in revised SRP-LR Table 3.0-1 in LR-ISG-2011-04 and noted that the UFSAR supplement is consistent with the description of the program in Table 3.0-1 in LR-ISG-2011-04 and is therefore acceptable. 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 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

This section contains the staff's evaluation of the applicant's RVI Inspection Plan, as amended in Reference 5. The RVI Inspection Plan is not an AMP; rather, it is a more detailed document that implements the elements of the RVI AMP. As such, the RVI Inspection Plan is a supporting document for the staff's review of the RVI AMP. An important aspect of the RVI Inspection Plan is the applicant's responses to the eight A/LAIs from the staff's final SE for MRP-227 dated December 16, 2011 (Ref. 9). The staff's review of the RVI Inspection Plan focused on assuring that these action items have been adequately addressed. The staff also reviewed the applicant's RVI Inspection Plan for general consistency with MRP-227-A with respect to the categorization of components for inspection, inspection methods, acceptance criteria, criteria triggering expansion of inspections, and evaluation methods for relevant conditions found during inspections.

This subsection is divided into the following subsections: an overview of the process used to develop the MRP-227-A aging management recommendations; regulatory evaluation; a brief summary of the major sections of the applicant's RVI Inspection Plan; the staff's technical evaluation of the RVI Inspection Plan, focusing on the A/LAIs and conditions of the staff's final SE for MRP-227, Revision 0; and the staff's conclusions.

Overview of the MRP-227-A Process. As the initial step in the process for developing the inspection recommendations of MRP-227-A, components were screened for eight different aging mechanisms. Components determined to be below the screening criteria for all aging mechanisms were designated Category A while those exceeding the criteria for at least one mechanism were designated "non-A." For the "non-A" components, failure modes, effects, and criticality analyses (FMECA) were performed to categorize each component as Category A, B, or C, with A being the least affected and C being the most affected. The components determined to belong to Category A in the initial screening were also reviewed by the FMECA expert panel to confirm their Category A status. Category B and C components were determined to need further evaluation and were subject to a functionality assessment. As a result of the functionality assessment, each RVI component was assigned to one of four functional groups:

- Primary: those PWR internals that are highly susceptible to the effects of at least one of the eight aging mechanisms were placed in the Primary group. MRP-227-A generally specifies inspections of Primary components or other aging management activities, such as analyses, with most inspections required within two refueling outages of the start of the period of extended operation. The Primary group also includes components which have shown a degree of tolerance to a specific aging degradation effect, but for which no highly susceptible component exists or for which no highly susceptible component is accessible.

- Expansion: those PWR internals that are highly or moderately susceptible to the effects of at least one of the eight aging mechanisms, but for which functionality assessment has shown a degree of tolerance to those effects, were placed in the Expansion group. The schedule for implementation of aging management requirements for Expansion components will depend on the findings from the examinations of the Primary components at individual plants.

- Existing Programs: those PWR internals in the Existing Programs group are susceptible to the effects of at least one of the eight aging mechanisms, and generic and plant-specific existing AMP elements are capable of managing those effects.

- No Additional Measures: those PWR internals for which the effects of all eight aging mechanisms are below the screening criteria were placed in the No Additional Measures group. Additional components were placed in the No Additional Measures group as a result of FMECA and the functionality assessment. No further action is required by these guidelines for managing the aging of the No Additional Measures components.

Aging management strategy development combined the results of functionality assessment with component accessibility, operating experience, existing evaluations, and prior examination results to determine the appropriate aging management methodology, baseline examination timing, and the need for and timing of subsequent inspections.

Augmented inspection recommendations are identified for each Primary and Expansion category component. The recommendations for the Primary components also identify timelines for the inspection. The inspection strategy generally employs VT-3 level visual examinations to evaluate general component condition, EVT-1 level enhanced visual examinations to identify surface-breaking flaws, and VT-1 level visual examinations to identify surface discontinuities such as gaps. Cracking in baffle-former bolts and core shroud bolts is monitored with UT techniques.

<u>Regulatory Evaluation</u>. 10 CFR Part 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants,” addresses the requirements for reactor license renewal. The regulation in 10 CFR Section 54.21, “Contents of Application—Technical Information,” requires that each application for license renewal contain an integrated plant assessment (IPA) and an evaluation of time-limited aging analyses (TLAAs). The plant-specific IPA shall identify and list those

structures and components subject to an AMR and demonstrate that the effects of aging (e.g., cracking, loss of material, loss of fracture toughness, dimensional changes, and loss of preload) will be adequately managed so that the intended functions of those structures and components will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.29(a). In addition, 10 CFR 54.22, "Contents of Application—Technical Specifications," requires that an LRA include any technical specification (TS) changes or additions necessary to manage the effects of aging during the period of extended operation as part of the LRA.

Structures and components subject to an AMP shall encompass those structures and components that (1) perform an intended function, as described in 10 CFR 54.4, without moving parts or without a change in configuration or properties and (2) are not subject to replacement based on a qualified life or specified time period. These structures and components are referred to as "passive" and "long-lived" structures and components, respectively.

On January 12, 2009, EPRI submitted Revision 0 of MRP-227 for NRC staff review and approval; it was intended as guidance for applicants in developing their plant-specific AMP for RVI components.

After the submittal of MRP-227 and before the issuance of the staff's SE for MRP-227, Revision 2 of the GALL Report was issued, providing new AMR line items and aging management guidance in AMP XI.M16A, "PWR Vessel Internals." This GALL AMP was based on staff expectations for the guidance to be provided in MRP-227-A.

Revision 1 to the final SE for MRP-227, Revision 0, was issued on December 16, 2011 (Ref. 9), with seven conditions and eight A/LAIs. The topical report conditions were specified to ensure that certain information was revised generically in the final NRC-approved version of MRP-227 (MRP-227-A) and the A/LAIs were specified for applicants and licensees to address plant-specific issues which could not be resolved generically in Revision 1 of the final SE for MRP-227-A. On January 9, 2012, EPRI published the NRC-approved version of the topical report, MRP-227-A (Ref. 3). MRP-227-A contains a discussion of the technical basis for the development of plant-specific AMPs for RVI components in PWR vessels and also provides inspection and evaluation guidelines for PWR applicants to use in their plant-specific AMPs. MRP-227-A provides the basis for renewed license holders to develop plant-specific inspection plans to manage aging effects on RVI components, as described by their FSAR commitments.

The scope of components considered for inspection under MRP-227-A includes core support structures (typically denoted as Examination Category B-N-3 by ASME Code Section XI) and those RVI components that serve an intended license renewal safety function under criteria in 10 CFR 54.4(a)(1). The scope of the program does not include consumable components such as fuel assemblies, reactivity control assemblies, and nuclear instrumentation because these components are not typically within the scope of the components that are required to be subject to an AMP, as defined by the criteria in 10 CFR 54.21(a)(1).

Because Revision 2 of the GALL Report was published before the issuance of the final SE for MRP-227-A, the staff published LR-ISG-2011-04 (Ref. 7), which modifies the guidance of AMP XI.M16A to be consistent with MRP-227-A.

The IP2 and IP3 LRA contained a list of commitments. Commitment No. 30 states: "For aging management of the RVI, IPEC will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval."

By letter dated September 28, 2011, Entergy submitted the "Indian Point Energy Center Reactor Vessel Internals Inspection Plan" (RVI Inspection Plan) intended to satisfy Item #3 of Commitment No. 30 to the License Renewal Application regarding the Aging Management Programs for RVI (Ref. 6). By letter dated February 17, 2012 (Ref. 5), Entergy submitted a revised RVI Inspection Plan reflecting the issuance of MRP-227-A.

Technical Evaluation. The staff reviewed the RVI Inspection Plan to determine whether it demonstrated that the effects of aging on the subject RVI components covered by the report would be adequately managed so that the components' intended functions would be maintained consistent with the current licensing basis for the period of extended operation, in accordance with 10 CFR 54.21(a)(3). Revision 1 of the SE for MRP-227, Revision 0, concluded that the MRP-227, Revision 0, report provides an acceptable demonstration that PWR applicants for license renewal will adequately manage the aging effects of the RVI components within the scope of the report, provided that the conditions and the A/LAIs in the SE are met. MRP-227-A incorporated all the conditions from the staff's SE. Therefore, the staff's technical evaluation of the RVI Inspection Plan focused on determining whether the plan is consistent with the recommendations of MRP-227-A and whether it addresses the plant-specific A/LAIs.

Action Items from Safety Evaluation of MRP-227, Revision 0. The staff's final SE for MRP-227, Revision 0 (Ref. 9), contained eight A/LAIs. The staff determined that A/LAIs 1, 2, 3, 5, 7, and 8 are applicable to IPEC and that A/LAIs 4 and 6 are not applicable to Westinghouse-designed RVI and therefore are not applicable to IPEC.

A/LAI 1

According to Section 4.2.1 of Reference 9, each applicant or licensee is responsible for assessing its plant's design and operating history and demonstrating that the approved version of MRP-227 is applicable to the facility. The action item states that each applicant or licensee shall refer, in particular, to the assumptions regarding plant design and operating history made in the FMECA and functionality analyses for reactors of their design (i.e., by Westinghouse, Combustion Engineering (CE), or Babcock & Wilcox (B&W)) which support MRP-227 and describe the process used for determining plant-specific differences in the design of their RVI components or plant operating conditions which result in different component inspection categories. The action item also states that the applicant or licensee shall submit this evaluation for NRC review and approval as part of its application to implement the approved version of MRP-227.

Applicant Evaluation

The applicant stated that IPEC has assessed its plant design and operating history and has determined that MRP-227 is applicable to its facility. The applicant further stated that the assumptions regarding plant design and operating history made in MRP-191 (Ref. 16) are appropriate for IPEC and that there are no differences in component inspection categories at IPEC. The applicant additionally indicated that IP2 operated for the first 8 years of operation with a high-leakage core pattern and IP3 operated for the first 10 years with a high-leakage core pattern; thus, both units are bounded by the FMECA and functionality analyses which were based on the assumption of 30 years of operation with high leakage core loading patterns. The applicant concluded that IPEC is bounded by the assumptions in MRP-191. The applicant further stated that IPEC has always operated as a base-load plant which operates at fixed power levels and does not vary power on a calendar or load-demand schedule.

Staff Evaluation

According to Section 2.4 of MRP-227-A, the following general assumptions were made in the analyses used to develop the MRP-227-A inspection recommendations:

- 30 years of operation with high leakage core loading patterns (fresh fuel assemblies loaded in peripheral locations) followed by implementation of a low-leakage fuel management strategy for the remaining 30 years of operation;

- base load operation, i.e., typically operates at fixed power levels and does not usually vary power on a calendar or load demand schedule; and

- no design changes beyond those identified in general industry guidance or recommended by the original vendors.

MRP-227-A Section 2.4 also states that (1) the guidelines are based on a broad set of assumptions about plant operation which encompass the range of current plant conditions for the U.S. domestic fleet of PWRs and (2) the functionality assessments and supporting aging management strategies in MRP-231, "Materials Reliability Program: Aging Management Strategies for B&W Pressurized Water Reactor Internals," and MRP-232, "Materials Reliability Program: Aging Management Strategies for Westinghouse and Combustion Engineering PWR Internal Components," provide the basis for these guidelines. MRP-227-A Section 2.4 further states that these evaluations were based on representative configurations and operational histories, which were generally conservative but not necessarily bounding in every parameter.

In RAI 6, the staff requested that the applicant provide additional information to support its conclusion that MRP-227-A is applicable to IP2 and IP3. In its September 28, 2012, response to RAI 6, the applicant provided additional detail on its process for demonstrating that IP2 and IP3 meet the three basic assumptions listed above, as well as additional details on the results of this assessment. The staff considers the following information from the licensee's response to RAI 6 to be relevant:

1. IP2 and IP3 started to change from a high-leakage to a low-leakage loading pattern in Fuel Cycle 6 and Fuel Cycle 4 respectively. In Fuel Cycle 6 (12/29/82) at 9 years of operation, IP2 switched to use of a low-low-leakage loading pattern (L^3P), and IP3 switched to low-low in Fuel Cycle 7 (6/24/1984). Then, in Fuel Cycle 12 (4/20/93) at 19 years of operation, IP2 switched to use of a low-low-low-leakage loading pattern (L^4P); IP3 made the same change in Fuel Cycle 14 (4/7/2005). Therefore, the applicant stated that IP2 and IP3 meet the fluence and fuel-management assumptions in MRP-191 and MRP-232 and the criteria for application of the MRP-227-A aging management strategy.

2. The IP2 RVI operate between T_{hot} and T_{cold}, which are not less than approximately 514 °F (515.5 °F before stretch power uprate (SPU)) for T_{cold} and

not higher than 605.8 °F (611.7 °F before SPU) for T_{hot}. The IP3 RVI operate between T_{hot} and T_{cold}, which are not less than approximately 517 °F (541.9 °F before SPU) for T_{cold} and not higher than 603 °F(600.8 °F before SPU) for T_{hot}. The design temperature for both vessels is 650 °F. Therefore, the applicant stated that IP2 and IP3 historical operation is within original design-basis parameters and is consistent with the assumptions used to develop the aging management strategy in MRP-227-A with regard to temperature operational parameters.

3. IP2 and IP3 have operated under base-load conditions over the life of the plant.

4. Modifications to the IP2 and IP3 RVI made over the lifetime of the plant are those identified in general industry guidance or specifically directed by Westinghouse. IP2 and IP3 performed SPUs in 2004 and 2005, at which time analyses were performed on RVI components and it was determined that the structural integrity of the reactor internals was maintained at the SPU conditions. The design has been maintained over the lifetime of the plant as specified by Westinghouse, and IP2 and IP3 have not made any modifications since May 2007, which meets the requirements of MRP-227-A. Operational parameters with regard to fluence and temperature are compliant with criteria in MRP-227-A and the components and materials are the same as those considered in MRP-191. Therefore, the applicant stated that the IP2 and IP3 stress values are reasonably represented by the assumptions in MRP-191, MRP-227-A, and MRP-232.

As described in Revision 1 of the staff's SE for MRP-227, Revision 0, the staff did not specifically state that verification of the three basic bulleted assumptions above was sufficient to verify plant-specific applicability of the guidelines. Section 3.2.5.1 of the staff's final SE for MRP-227-A provides additional background on the staff's concerns regarding plant-specific applicability verification. A series of public and non-public meetings were conducted (References 17 through 21), at which the NRC, Westinghouse, the Electric Power Research Institute (EPRI), and utility representatives discussed the staff's regulatory concerns and determined a path for a comprehensive and consistent utility response to demonstrate applicability of MRP-227-A, specifically for Westinghouse- and CE-designed PWR RVI. A summary of the proprietary meeting presentations and supporting proprietary generic design-basis information is contained in Westinghouse proprietary report WCAP-17780-P (Ref. 22). WCAP-17780-P provides background proprietary design information regarding variances in stress, fluence, and temperature in the plants designed by Westinghouse and CE to support NRC reviews of utility submittals to demonstrate plant-specific applicability of MRP-227-A.

As a result of the technical discussions with the staff, the basis for a plant to respond to the NRC's RAI to demonstrate compliance with MRP-227-A for originally licensed and uprated conditions was determined to be satisfied with plant-specific responses to the following two questions (References 19 and 21):

> Question 1: Does the plant have non-weld or bolting austenitic stainless steel (SS) components with 20 percent cold work or greater, and, if so, do the affected components have operating stresses greater than 30 ksi [kilopounds per square inch]? (If both conditions are true, additional components may need to be screened in for stress corrosion cracking, SCC.)

> Question 2: Does the plant have atypical fuel design or fuel management that could render the assumptions of MRP-227-A, regarding core loading/core design, non-representative for that plant? [Reference 19 indicated that this question covers power uprates as well as other core design and fuel management aspects.]

By letter dated October 14, 2013 (MRP 2013-025, "MRP-227-A Applicability Template Guideline" (Ref. 23)), EPRI provided to applicants a non-proprietary document containing guidance for responding to the two questions above. With respect to Question 1, Reference 23 provides guidance for applicants to assess whether RVI components at their plants, other than those identified in the generic evaluation, have the potential for cold work greater than 20 percent. With respect to Question 2, Reference 23 provides quantitative criteria to allow an applicant to assess whether a particular plant has atypical fuel design or fuel management. For Westinghouse-designed plants such as IP2 and IP3, these criteria are:

(1) The heat generation rate must be less than or equal to 68 watts/cm^3.

(2) The maximum average core power density must be less than 124 watts/cm^3.

(3) The active fuel to upper core plate (UCP) distance must be greater than 12.2 inches.

The staff's review of Reference 23, and the supporting technical information in WCAP-17780-P will be documented and issued in the near future. The staff has determined that if an applicant or licensee demonstrates that its plant(s) comply with the guidance in MRP 2013-025, there is reasonable assurance that the I&E guidance of MRP-227-A will be applicable to the specific plant(s). The guidance in MRP 2013-025 provides an acceptable basis for licensees to prepare responses to the generic RAI questions. The staff has further determined that the recommended criteria provide (1) a systematic process for an applicant or licensee to assess whether its RVI contain cold-worked materials that may be susceptible to SCC and (2) quantitative measures of whether a plant is operating with a low-leakage core design as assumed by MRP-227-A.

The staff also determined that the criteria and guidance for verification of plant-specific applicability are acceptable because (1) the information provided on evaluation of cold work in WCAP-17780-P provides an adequate technical basis for the guidance in MRP 2013-025 for responding to Question 1 and (2) the sensitivity studies of variations in neutron fluence, RVI geometry, and temperature documented in WCAP-17780-P, as well as the information on power uprate effects on fluence and temperature documented in WCAP-17780-P, provide an acceptable technical basis for the guidance in MRP 2013-025 for responding to Question 2, with the exception of one open item detailed in Section 3.3.2 that is not applicable to Westinghouse-designed RVI and thus is not applicable to IP2 or IP3.

In RAI 6-A, the staff requested that the applicant respond to the following questions, which are essentially identical to the questions given in MRP 2013-025:

1. Do the IP2 and IP3 RVI have non-weld or bolting austenitic stainless steel components with 20% cold work or greater, and if so do the affected components have operating stresses greater than 30 ksi? If so, perform a

plant-specific evaluation to determine the aging management requirements for the affected components.

2. Have IP2 and IP3 ever utilized atypical fuel design or fuel management that could make the assumptions of MRP-227-A regarding core loading/core design non-representative for that plant, including power changes/uprates? If so, describe how the differences were reconciled with the assumptions of MRP-227-A or provide a plant-specific aging management program for affected components as appropriate.

In its January 16, 2014, response to RAI 6-A, Question 1 (Ref. 24), the applicant stated it followed the guidance of Reference 23. Specifically, the applicant stated that it evaluated the IP2 and IP3 RVI according to the MRP-191 industry generic component listings and screening criteria (including consideration of cold work as defined in MRP-175, "Materials Reliability Program: PWR Internals Material Aging Degradation Mechanism Screening and Threshold Values" (Ref. 25), noting the requirements of Section 3.2.3). In addition to consideration of the material fabrication, forming, and finishing process, the applicant stated that a general screening definition of a resulting reduction in wall thickness of 20 percent was applied as an evaluation limit. The applicant stated that it had confirmed that all of the Indian Point Unit 2 and Unit 3 components, as applicable for the design, are included directly in the MRP-191 component lists, except for the components identified in Table 1 of the applicant's response. Table 1 of the applicant's response listed the IP2 and IP3 components fabricated from materials different from the generic material identified in MRP-191. (These are the same components as those with the material differences evaluated in the applicant's calculation audited by the staff as documented in the staff's audit report (Ref. 27).) The applicant further stated that this evaluation included an evaluation of all modifications performed on the RVI that confirmed that no non-bolting components were subject to cold work greater than 20 percent as a result of construction, except for those components of material types already assumed to have greater than 20 percent cold work in the generic evaluations. Finally, the applicant concluded that there was no impact to the MRP-227-A sampling inspection aging management requirements as a result of this review. The staff finds the applicant's response to RAI 6-A Question 1 to be acceptable because the applicant confirmed that all of the IP2 and IP3 RVI components with differences from the generic material identified in MRP-191, and those components affected by modifications to the RVI, do not have greater than 20 percent cold work unless they are already included in a material category that is generically assumed to have greater than 20 percent cold work (such as bolting).

In response to RAI 6-A, Question 2, the applicant confirmed that both IP2 and IP3 switched to an out-in (low-leakage) core design before 30 EFPY of operation and stated that all future operation would use low-leakage fuel management. The applicant provided the specific value of the maximum average core power density for IP2 and IP3 for the last four operating cycles, which is less than 124 watts/cm^3 as specified by Reference 23. The applicant also provided the specific range of the heat-generation rate figure of merit based on the last four cycles of operation for IP2 and IP3, which did not exceed 68 watts/cm^3. The applicant also provided the nominal distance between the top of the active fuel to the UCP for first 21 cycles for IP2 and the first 18 cycles for IP3, both of which are greater than the value of 12.2 inches required by Reference 23. For all three parameters, the applicant stated that these values were representative of anticipated future operation during the period of extended operation. Therefore, because the applicant's response indicates that IP2 and IP3 meet the numerical criteria of Reference 23, the staff finds that IP2 and IP3 do not have atypical fuel design or fuel management that could make the assumptions of MRP-227-A regarding core loading or core design non-representative for that plant.

In sum, the applicant adequately addressed the two factors for which the staff determined that additional plant-specific information was necessary to verify applicability of MRP-227-A to IP2 and IP3 – (1) cold work induced stress; and, (2) fuel management – by confirming that IP2 and IP3 comply with the criteria defined in the guidance document (Ref. 23). Furthermore, the applicant confirmed that IP2 and IP3 will continue to comply with these limits during the period of extended operation. Therefore the staff finds the applicant's response acceptable, the staff's concerns in RAI 6 and RAI 6-A are resolved, and Action Item 1 is resolved for IP2 and IP3.

A/LAI 2

According to Section 4.2.2 of Reference 9, this action item states that, to be consistent with the requirements addressed in 10 CFR 54.4, each applicant or licensee is responsible for identifying which RVI components are within the scope of LR for its facility. This action item states that "[a]pplicants/licensees shall review the information in Tables 4-1 and 4-2 in MRP-189, Revision 1, and Tables 4-4 and 4-5 in MRP-191 and identify whether these tables contain all of the RVI components that are within the scope of LR for their facilities in accordance with 10 CFR 54.4." (Note: Table 4-4 of MRP-191 is the applicable table for Westinghouse-designed RVI). The action item further states that "[i]f the tables do not identify all the RVI components that are within the scope of LR, the applicant or licensee shall identify the missing component(s) and propose any necessary modifications to the program defined in MRP-227, as modified by [the final SE for MRP-227, Revision 0], when submitting its plant-specific AMP. The AMP shall provide assurance that the effects of aging on the missing component(s) will be managed for the period of extended operation."

<u>Applicant Evaluation</u>

The applicant stated that IPEC reviewed the information in Table 4-4 of MRP-191 and determined that this table contains all the RVI components that are within the scope of license renewal. The applicant also stated that this is shown in Table 5-7 of the inspection plan.

<u>Staff Evaluation</u>

The intent of this action item is to ensure that all components that are within scope of LR for a plant have been considered in the process used to develop the aging management requirements for the RVI, so that a plant-specific AMP can be developed for any component(s) not covered by the generic evaluation. The staff finds the applicant's response to A/LAI 2 generally acceptable because the applicant verified that all of the IPEC RVI components are addressed in Table 4-4 of MRP-191. The staff notes that Table 5-1 contains a cross-index between the component designations in Entergy Letter NL-10-063 (LRA Amendment 9, Ref. 1) and the component names as designated in MRP-191, Table 4-4. All of the IPEC component designations correspond to an equivalent component designation in MRP-191, Table 4-4 with the exception of the Lower Internals Assembly—Column Cap. Therefore, in RAI 7, the staff requested that the applicant verify that the column cap would be subject to the same inspection requirements that are applied to the lower support assembly's lower support column bodies (cast) in MRP-227, Table 4-6. In its September 28, 2012, response to RAI 7 (Ref. 27), the applicant confirmed that the column cap is subject to the same inspection requirements as the lower support column bodies (cast), because the lower support column and column cap form a single welded assembly that was considered as one complete unit denoted as the lower support column assemblies—lower support column bodies in MRP-191. Therefore, the column caps would be covered by the MRP-227-A Expansion inspection of the lower support column bodies. The staff's concern in RAI 7 is therefore resolved. In addition, as clarified by the applicant's RAI 7 response, the staff's review of Table 5-1 of the RVI Inspection Plan confirms that all of the RVI components within the scope of LR have an equivalent generic component in MRP-191 and thus are covered by the MRP-227-A aging management recommendations.

In its September 28, 2012, response to RAI 6 (Ref. 27), the applicant noted that there were some differences between materials in the IP2 and IP3 components and the generic material assumed for these components in MRP-191. The applicant stated that most of the IP2 and IP3 RVI component materials are consistent with or nearly equivalent to those materials identified in MRP-191 Table 4-4 for Westinghouse-designed plants except for a few components that were fabricated from CF8 cast austenitic stainless steel (CASS) material rather than the Type 304 stainless steel (SS) identified in MRP-191. The applicant further stated that these items, along with the items that were fabricated from different but essentially equivalent materials, are summarized in a Westinghouse proprietary letter. On April 24 and 25, 2013, as documented in the staff's October 17, 2013, audit report, the staff audited the proprietary calculation in which the plant-specific material differences from MRP-191 are evaluated (Ref. 26). The staff found the applicant's evaluation of the material differences to be acceptable because in all but one case, the materials were essentially equivalent to the generic material in MRP-191, and the applicable degradation mechanisms and the severity of the mechanisms are bounded by the results for the MRP-191 generic material. In the case mentioned above in which the plant-specific component is fabricated from CF8 rather than from Type 304, the applicant performed a plant-specific FMECA for this component that resulted in no new aging management requirements for this component. The staff found the applicant's plant-specific FMECA acceptable because it followed the same process used to develop the generic aging management requirements for RVI components in MRP-227-A.

The staff finds the applicant's response to A/LAI 2 acceptable because the applicant verified that all components within the scope of LR are covered by MRP-191, which the staff confirmed, and the staff's audit determined that the applicant's evaluation of components found to be fabricated from materials different from the generic material assumed in MRP-191 was acceptable.

A/LAI 3

According to Section 4.2.3 of Reference 9, this action item requires applicants and licensees of CE and Westinghouse plants to perform a plant-specific analysis either to justify the acceptability of the applicant's or licensee's existing programs or to identify changes to the programs that should be implemented to manage the aging of certain components for the period of extended operation. The action item also requires the results of this plant-specific analyses and a description of the plant-specific programs being relied on to manage aging of these components to be submitted as part of the applicant's or licensee's AMP. The Westinghouse components identified for this type of plant-specific evaluation are the guide-tube support pins (split pins) (Section 4.4.3 of MRP-227-A).

Applicant Evaluation

The applicant described its program for aging management of the guide-tube support pins (split pins) in its response to this action item. The original split pins in both units have been replaced. At IP2, the original Alloy X-750 split pins were replaced in 1995 with an improved Alloy X-750 Revision B material[2] made from more selective material with more continuous carbide coverage on the grain boundaries and tighter quality controls to provide greater resistance to stress corrosion cracking. The applicant further stated that IP2 plans to begin preliminary split-pin replacement engineering and walkdowns in 2014 and to replace the split pins in 2016.

The applicant stated that at IP3 the original Alloy X-750 split pins were replaced in 2009 with cold-worked Type 316 stainless steel, and that the cold-worked Type 316 stainless steel is a significant improvement over Alloy X-750. The applicant further stated that, based on operating experience, the IP3 split pins are expected to last through the end of the period of extended operation.

Staff Evaluation

The applicant has replaced split pins in both units with split pins fabricated with a more SCC-resistant material. For IP3, the applicant indicated that the replacement split pins are expected to last through the end of the period of extended operation. In RAI 8, the staff requested more detail on the operating experience supporting this conclusion and whether inspections of the IP3 split pins are planned during the period of extended operation. In RAI 8, the staff also requested more detail on the criteria for the replacement split pins at IP2. In its June 14, 2012, response to RAI 8 (Ref. 4), the applicant stated that cold-worked Type 316 split pins have been in service in PWRs since 1997 with no recorded failures. The applicant indicated that future replacement of the IP2 split pins would also use cold-worked Type 316 stainless steel. The applicant indicated that no inspections of split pins are currently planned for the period of extended operation; however, the need for inspections would be reevaluated if failures of split pins of the same material occurred in other PWRs. The staff reviewed the applicant's response and a summary of information from the literature on the SCC susceptibility of cold-worked Type 316 stainless steel in PWRs in Reference 22 and concludes that the applicant's response to RAI 8 with respect to the predicted life of the IP3 replacement split pins is acceptable because (1) there has been no OE indicating occurrence of SCC of Type 316 split pins and (2) the applicant will address any future related OE under its internal OE evaluation process. The staff's concern in RAI 8 is thus resolved.

The staff understands that the ASME Code VT-3 visual examination of the split pins, if performed, would be of limited value because the pins are mostly inaccessible for inspection and the ASME Code only requires visual inspection of "accessible surfaces." However, because no basis for the proposed replacement date of the IP2 split pins was

[2] Revision B is a proprietary Westinghouse specification for Alloy X-750 material.

provided, in RAI 16, the staff asked the applicant to justify the proposed replacement date for the IP2 split pins, considering that no inspections are planned before replacement, and to propose inspections if these are necessary to justify the replacement date or if replacement is delayed. In response to RAI 16, by letter dated November 20, 2012 (Ref. 28), the applicant provided an evaluation justifying the planned replacement date for the IP2 split pins. The applicant's evaluation included a description of the design changes that were made in the currently installed split pins at IP2, compared to the original split pins. These design changes resulted in lower susceptibility to SCC by lowering the residual stresses, reducing stress concentration effects, improving surface condition, and increasing the material's resistance to SCC. The applicant also noted that the pin material was procured to a newer Westinghouse specification which incorporates all the requirements in the Revision B specification as well as addressing EPRI recommendations provided in EPRI Report N-7032. The applicant also indicated that the material was procured to the HTH condition[3], which is heat treated at a higher temperature than earlier heat treatments applied to Alloy X-750 material. The applicant confirmed that the IP2 pins meet the requirements of the Revision B specification, the HTH condition, and the recommendations of EPRI N-7032 through a review of the Certified Material Test Reports.

The applicant's response also included an evaluation of the operating experience from plants in the Westinghouse fleet having the same material as the IP2 spit pins. The evaluation normalized the operating time to split pin failure for the other plants (in terms of effective full-power hours (EFPH)) using an Arrhenius relationship to adjust for differences in the operating temperature and stress of the IP2 pins versus the pins in the other plants.

The applicant's response to RAI 16 also provided the equation for the stress caused by temperature in the shank region, which is a function of the pin geometry and the temperature range during heatup to full operating temperature.

The applicant presented data for shank failures and failures of pin leaves for other plants with the Revision B material.

For split pin shank failures, there were 12 plants and 37 individual pin failures in the data set. An average pin failure time of 296,700 EFPH and a standard deviation of 48,500 EFPH were determined from the data. The projected operating time for IP2 in 2016 of 152,000 EFPH is considerably below the lower two-standard-deviation bound (-2σ) of 199,700 EFPH.

For the failures of pin leaves, only two plants had failures. The average failure time for the pin leaves is 238,200 EFPH and the minimum time was 232,700 EFPH.

Based on the projected operating time for IP2 until pin replacement compared to the normalized operating times to pin failure from the reference plants, the applicant concluded there was a very low probability of split pin cracking due to SCC before the planned replacement date.

[3] high-temperature annealed and aged condition heat treatment

A review of operating experience related to Alloy X-750 split pins summarized in EPRI document 1002792, "Materials Handbook for Nuclear Plant Pressure Boundary Applications," reveals that the HTH condition for this alloy is more resistant to SCC than other heat treatments applied to this alloy, but is not immune from SCC if stress levels are high enough and surface damage is present. The staff agrees that the design improvements incorporated in the currently installed Alloy X-750 split pins at IP2 should minimize these deleterious effects because the design improvements will reduce the overall stress level in the split pins and result in a better surface condition.

The staff also reviewed the split pin failure data from other plants presented by the applicant. The staff estimated the failure rate of the split pins at the planned replacement time for IP2 by fitting the failure data for the pin shanks to two different statistical distributions. If a normal distribution is assumed, the probability that a pin would fail at 152,000 EFPH or less is 0.0014 or 0.14 percent. If a Weibull distribution is assumed, the failure probability at 152,000 EFPH is 0.0075 or 0.75 percent.

The applicant also stated in its response to RAI 16 that if the planned replacement of the IP2 split pins is not implemented in 2016, it would provide the staff with detailed inspection plan for the split pins by March 2015. In RAI 16-A the staff requested the applicant to add a commitment to provide the inspection plan. In its September 27, 2013, response to RAI 16-A (Ref. 12), the applicant proposed Commitment No. 50 to provide the staff a detailed inspection plan for the IP2 split pins, including inspection methods, inspection coverage, and inspection frequency, by March 31, 2015, if the planned replacement of the pins would not be accomplished in 2016. In RAI 16-B, the staff requested the applicant to submit the schedule for initial inspection, inspection methods, inspection coverage, and inspection frequency for the IP2 split pins if the IP2 split pins are not replaced by 2016 and requested that Commitment No. 50 be modified accordingly. In its June 9, 2014, response to RAI 16-B (Ref. 14), the applicant revised Commitment No. 50 to state, "Replace the IP2 split pins during the 2016 refueling outage (2R22)." The staff finds the revised Commitment No. 50 acceptable.

Based on the design changes made in the current IP2 split pins to reduce SCC susceptibility, the operating experience of other plants with material similar to the current IP2 split-pin material, and the staff's independent review confirming the conservatism of the applicant's life prediction for the split pins, the staff finds the applicant's justification of its planned replacement date to be acceptable. The staff's concern in RAIs 16, 16-A, and 16-B are thus resolved.

The staff finds that the applicant's plant-specific program for split pins is acceptable because the existing pin replacement date has been justified and the date formalized through a license commitment and because materials with enhanced SCC resistance are used or will be used for the pins.

A/LAI 5

According to Section 4.2.5 of Reference 9, and as applicable to IPEC, this action item requires applicants and licensees to identify plant-specific acceptance criteria to be applied when performing the physical measurements required by the NRC-approved version of MRP-227-A for loss of compressibility for Westinghouse hold down springs. The action item states that the applicant or licensee shall include its proposed acceptance criteria and an explanation of how the proposed acceptance criteria are consistent with the plant's licensing basis and the need to maintain the functionality of the component being inspected under all licensing basis conditions of operation as part of its submittal to apply the approved version of MRP-227.

Applicant Evaluation

In response to A/LAI 5, the applicant stated that the IPEC plant-specific acceptance criteria for hold-down springs will be developed before the first required physical measurement, as will an explanation of how the proposed acceptance criteria are consistent with the IPEC licensing basis and the need to maintain the functionality of the hold-down springs under all licensing basis conditions. The applicant further stated that (1) the acceptance criteria will ensure that the remaining compressible height of the spring shall provide hold-down forces within the IPEC design tolerance and (2) if a plant-specific acceptance criterion is not developed for the hold-down spring, IPEC will replace the spring in lieu of performing the first required physical measurement.

Staff Evaluation

In reviewing the applicant's response to A/LAI 5, the staff noted that MRP-227-A, Table 4-3, calls for direct measurement of the hold-down spring height within three cycles of the beginning of the license renewal period. If the first set of measurements is not sufficient to determine remaining life, spring height measurements must be taken during the next two outages in order to extrapolate the expected spring height to 60 years.

The staff needed clarification as to how IPEC would determine whether the first set of measurements could be extrapolated to demonstrate acceptable spring functionality through 60 years; therefore, in RAI 9, the staff requested the following information: (1) the specific acceptance criteria for spring height and/or hold-down force from the IP2/IP3 licensing basis, (2) the procedure by which the remaining hold-down forces will be projected to end-of-life based on one measurement, and (3) what results of the first spring measurements would indicate a need for successive measurements.

In its September 28, 2012, response to RAI 9 (Ref. 27), the applicant indicated that the acceptance criteria are a function of spring height as a function of time relative to the required hold-down force. The applicant further indicated that the details of the measurements are proprietary and cited a Westinghouse letter. The decrease in the hold-down spring height is assumed to occur linearly over time. The approach linearly interpolates the required minimum spring height at the time of measurement between the spring height at startup and the minimum spring height at 60 years. If the first spring height measurement is less than the required height, successive (additional) measurements of spring height will be performed or the hold-down spring will be replaced.

The staff audited the proprietary calculation of the hold-down spring acceptance criteria on April 24 and 25, 2013 as documented in its October 2013, audit report (Ref. 26). The calculation clarified the relationship of the acceptance criteria with the IP2 and IP3 design bases. Also during the audit, Westinghouse presented information explaining the conservatism of assuming that the hold-down spring force decreases linearly with time.

The staff finds the response to RAI 9 acceptable because the applicant described the criteria for determining whether the spring measurement is acceptable. The pre-startup spring height measurement and the spring height measurement to be performed later provide two data points for the decrease of spring height over time. Further, if the spring height is below what it should be according to the linear assumption, the proposed corrective actions are reasonable. The staff's concern in RAI 9 is therefore closed.

The staff finds the applicant's response to A/LAI 5 acceptable because the applicant has provided a plant-specific acceptance criterion for the remaining compressible height or hold-down force of the hold-down spring.

A/LAI 7

As applicable to IPEC, this action item requires the applicants and licensees of Westinghouse reactors to develop plant-specific analyses to be applied for their facilities to demonstrate that lower support column bodies will maintain their functionality during the period of extended operation. These analyses should also consider the possible loss of fracture toughness in these components due to TE and IE. The action item further states that the plant-specific analysis shall be consistent with the plant's licensing basis and the need to maintain the functionality of the components being evaluated under all licensing basis conditions of operation. Lastly, the action item states that applicants and licensees shall include the plant-specific analysis as part of their submittal to implement the approved version of MRP-227.

Applicant Evaluation

The applicant stated that the IPEC plant-specific analyses to demonstrate the lower support column bodies will maintain their functionality during the period of extended operation will include consideration of the possible loss of fracture toughness in these components due to TE and IE. The analyses will be consistent with the IPEC licensing basis and with the need to maintain the functionality of the lower support column bodies under all licensing basis conditions of operation. The applicant further stated that IPEC will submit this information to the NRC before the period of extended operation.

Staff Evaluation

In the aging management review tables submitted in LRA Amendment 9, the applicant credits the "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program" for managing loss of fracture toughness of the lower core support column bodies, as well as several other CASS components. The staff's SER, NUREG-1930, indicates that the staff determined that this program was consistent with AMP XI.M13, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program," in Revision 1 of the GALL Report. Section XI.M13 of Revision 1 of the GALL Report recommends supplemental visual inspections (equivalent to an EVT-1) for CASS RVI components that either (1) are susceptible to thermal aging based on chemistry and other manufacturing parameters or (2) receive a neutron fluence greater than 1×10^{17} n/cm^2, unless it can be demonstrated that the stresses on the component are either compressive or low in magnitude if tensile. The RVI Program is credited with managing cracking of the core support column bodies and other CASS components. Under the RVI Program, the core support column bodies are Expansion components that would be subject to an EVT-1 visual examination for cracking due to IASCC if cracking were found in the associated Primary component. Because the plant-specific analysis for A/LAI 7 and the GALL Section XI.M13 Program could both potentially involve screening for TE or IE, stress analyses, and flaw tolerance evaluations, and both the RVI Program and GALL XI.M13 Program could potentially require inspections, in RAI 10 the staff requested that the applicant discuss the relationship of the two programs and the plant-specific analysis.

In its September 28, 2012, response to RAI 10 (Ref. 27), the applicant stated that the RVI Program is the base program that addresses the RVI components that require aging management and specifies inspection requirements. The Thermal Aging and Neutron Irradiation Embrittlement of CASS Program at IPEC augments the RVI Program by evaluating the potential susceptibility of plant-specific CASS components based on component-specific chemistry. The staff finds the applicant’s response to RAI 10 acceptable because it clarified the relationship and the division of activities between Revision 1 of the GALL Report’s XI.M13 Program and the RVI Program with respect to RVI CASS components. The staff’s concern in RAI 10 is thus resolved.

The staff determined that, for IP2 and IP3, the only CASS components requiring a plant-specific evaluation under Action Item 7 are the lower core support column bodies (column caps), because these are the only Primary or Expansion category CASS components in Westinghouse-designed RVI. The lower core support column bodies (cast) are Expansion components in MRP-227-A. The applicant’s September 28, 2012, response to RAI 7 clarified that the lower support column bodies and column caps form a single welded assembly that is equivalent to the generic MRP-227-A component lower core support column bodies (cast). However, as clarified in the September 27, 2013, response to RAI 11-B (Ref. 12), only the column cap, which makes up the upper portion of the lower core support column body assembly, is CASS. The Primary link for the lower support column bodies (cast) is the control-rod guide tube’s (CRGT’s) lower flange welds.

Because the applicant deferred providing the analysis for review by the staff, in RAI 11 the staff requested additional information on the approach to be used and on the acceptance criteria for the plant-specific analysis, as well as a commitment to submit the plant-specific analysis. Section 3.3.7 of Revision 1 of the staff's final SE for Revision 0 of MRP-227 lists three possible options for the type of plant-specific analysis used to fulfill the requirements of this action item. The three approaches are (1) functionality analyses of the set of like components, (2) component-specific flaw tolerance evaluations, or (3) a screening approach demonstrating that the CASS Components are not susceptible to thermal embrittlement, neutron embrittlement, or the combined effects of both. In its June 14, 2012, initial response to RAI 11 (Ref. 4), the applicant deferred providing the information on the approach until September 28, 2012, but proposed Commitment No. 47 stating that it “…will perform and submit analyses that demonstrate that the lower support column bodies will maintain their functionality during the period of extended operation considering the possible loss of fracture toughness due to thermal and irradiation embrittlement. The analyses will be consistent with the IP2/IP3 licensing basis and will be submitted prior to the PEO.”

In its September 28, 2012, final response to RAI 11 (Ref. 27), the applicant indicated that the plant-specific evaluation would use a screening approach. The applicant provided screening criteria for susceptibility to TE based on the material chemistry, delta ferrite content, and casting method. The applicant cited NRC letter “License Renewal Issue No. 98-0030, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components,” dated May 19, 2000 (Ref. 29), as the source of the screening criteria. Essentially, these criteria determine the potential susceptibility to TE based on whether the CASS is high molybdenum or low molybdenum, the delta ferrite content, and whether static or centrifugal casting was used to make the component.

The staff's May 19, 2000, letter notes that, for CASS RVI components, there is a potential synergistic effect between TE and IE that could reduce the fracture toughness to a greater degree than would be predicted based on the additive effect of both mechanisms. Therefore, the staff's May 19, 2000, letter specifies a threshold neutron fluence of 1×10^{17} n/cm^2 above which the TE screening criteria may not be applied. For components subject to this potential synergistic effect, a component-specific evaluation was recommended that would evaluate the mechanical loading on the components. Supplemental inspections would be indicated for components subject to significant tensile stresses under any loading condition. According to MRP-191, the range of the maximum neutron fluence for the lower support column bodies for Westinghouse-designed RVI is 1×10^{22} n/cm^2 to 5×10^{22} n/cm^2, which is well above the threshold identified in the staff's May 19, 2000, letter. Therefore, in accordance with the guidance of the staff's May 19, 2000, letter, the TE screening criteria cannot be applied to the upper portion of the column caps.

Because the applicant did not address the potential synergistic effect of TE and IE in its response to RAI 11, the staff requested that the applicant address this effect in RAI 11-A. In its May 7, 2013, response to RAI 11-A (Ref. 30), the applicant provided its revised approach for screening for loss of fracture toughness and its position on the need to consider the synergistic effect. The applicant described screening criteria similar to the TE screening criteria in the staff's May 19, 2000, letter, with the modification that materials that screened out for TE would screen in for IE if the components receive a neutron fluence greater than or equal to 6.7×10^{20} n/cm^2 (1 displacement per atom (dpa)).

The applicant's justification for the modified screening criteria is summarized as follows: TE susceptibility of CASS depends on the distribution of the ferrite phase in the microstructure. If the ferrite is distributed in such a way that it forms a continuous phase, the material can become susceptible to brittle fracture at relatively low neutron fluences. Whether the ferrite can form a continuous phase is a function of the amount of ferrite in the material, which is the basis for the screening criteria in the staff's May 19, 2000, letter. Therefore, if a CASS material screens out for TE, IE of the ferrite constituent would be insignificant because the ferrite phase would be isolated within the austenitic matrix. However, if the material did screen in for TE, there is no need to consider the effect of IE on the ferrite phase as well because the end-of-life (saturation) fracture toughness would be unacceptable because of TE alone, thus creating the need for the functionality analysis to be performed. The onset of IE of the austenite phase of CASS occurs at fluences of around 1 dpa (6.7×10^{20} n/cm^2). The applicant cited NUREG/CR-6960, "Crack Growth Rates and Fracture Toughness of Irradiated Austenitic Stainless Steels in BWR [Boiling-Water Reactor] Environments" (Ref. 31), and NUREG/CR-7027, "Degradation of LWR [Light-Water Reactor] Core Internal Materials due to Neutron Irradiation" (Ref. 32), in support of the use of this fluence value. Therefore, the applicant concluded that the fracture toughness will either be controlled by TE of ferrite (for high ferrite CASS) or IE of austenite (for low ferrite CASS).

The applicant's response to RAI 11-A also indicated that the lower support columns screen in for IE based on the criteria of MRP-191 because the columns are expected to receive a fluence of 1×10^{22} n/cm^2 (15 dpa) to 5×10^{22} n/cm^2 (75 dpa) as reported in

Table 4-6 of MRP-191. The applicant further indicated that because "the effects of embrittlement are only significant in the presence of pre-existing flaws (such as from the casting process) and tensile stresses capable of propagating these flaws, the screening analysis will identify regions of individual columns where thermal and irradiation effects could embrittle the material and would also be subject to significant tensile stresses…" The applicant further indicated that a functionality assessment would be conducted for such regions to determine the impact of column fracture on the lower core support columns. The applicant also stated that, based on the lack of any documented history of fracture in the lower core support columns, it will be assumed that only a limited number of columns could actually contain flaws of significant size, and that the assessment will evaluate distributions of fractured columns that can be tolerated without the loss of the critical core support function.

The response to RAI 11-A indicated that a functionality assessment would be performed that would determine tolerable distributions of fractured columns, but did not provide a detailed basis for the incidence of flaws in the columns in the absence of inspection data (i.e., how many columns will be assumed to be cracked) and did not define the tensile stress level that would be considered significant in the functionality analysis. These issues were the subject of RAI 11-B. In its September 27, 2013, response to Part 1 of RAI 11-B (Ref. 12), the applicant provided more detail on the basis for assuming a very low incidence of cracking for the columns. A liquid penetrant-testing (PT) examination and radiography of the columns were required during manufacturing of the columns; no surface-breaking defects were detected on any of the columns. The applicant's response also addressed the possibility of service-induced defects. The applicant's response indicated that, although both IASCC and fatigue screened in as possible cracking mechanisms during the development of MRP-227-A, the stresses in the columns are too low to cause IASCC, which (according to MRP-175) would require stresses of 70 ksi or greater at the neutron fluence levels expected for the columns at IPEC, compared to the nominal normal operating stresses on the columns, which are on the order of 20 ksi. The response to RAI 11-B did not provide the expected neutron fluence for the column caps. Using the curve of stress versus dpa corresponding to IASCC susceptibility from MRP-191 Section 3.2, the staff determined that a stress of 70 ksi corresponds to a neutron exposure of 7 dpa. By contrast, using the same curve, if the maximum stress is 20 ksi, the staff determined a neutron exposure of approximately 60 dpa would be required for IASCC. Thus, the neutron fluence for the IP2 and IP3 column caps is considerably less than the estimated neutron exposure for the generic Westinghouse lower core support columns of 15 to 75 dpa used for screening purposes in MRP-191.

With respect to cracking due to fatigue, the applicant's response to RAI 11-B indicated that environmentally adjusted fatigue cumulative usage factors (CUF_{en}) have been calculated for the IP2 columns, and these values are less than 1.0, demonstrating that fatigue initiation is not expected during the life of the plant. In Part 2 of RAI 11-B, the staff asked if there was a specific numerical threshold representing "significant tensile stress." In response, the applicant stated that there was a value in Section XI.M13 of the GALL Report, Revision 1, but that no complete columns were screened out based on stress.

In Part 3 of RAI 11-B, the staff requested details on the materials and fabrication of the columns. The key parts of the applicant's response are that the upper portion of the columns are statically cast Type CF-8, the lower part is wrought stainless steel, and a weld between the cast and wrought portions is located approximately 18 inches below the lower core plate.

In Part 4 of RAI 11-B, the staff requested a summary of the most recent ASME Code Section XI Inservice Inspection of the lower support columns at IP2 and IP3, including the dates of the inspections, coverage obtained, and the size, location and orientation of any recordable or rejectable indications. The applicant's September 27, 2013 response indicated that the most recent inspection dates for the ASME Section XI Category B-N-3 inspection of the core support structure were May 2006 for IP2 and March 2009 for IP3, but for both units, only the wrought portion of the lower support column bodies below the dome lower support plate was inspected. The applicant further stated the inspections for both units were satisfactory with no recordable or rejectable indications noted. The staff notes that the applicant's response to Part 4 of RAI 11-B confirms that the CASS portion of the columns is not accessible for the ASME Code Section XI required VT-3 visual examination, and that no meaningful information regarding the structural integrity of the columns can be obtained from the most recent ASME Code Section XI examinations of the columns.

In its response to Part 5 of RAI 11-B, the applicant revised its commitment date for IP2 to provide its detailed functionality analysis for the lower core support columns from March 1, 2015, to August 15, 2014, in order to provide the staff the requested 18-month period to review the detailed analysis before the 2016 refueling outage for IP2, during which the MRP-227-A Primary inspections will be performed (Commitment 47).

During a phone call on December 18, 2013, the staff informed the applicant that the staff is considering the development of screening criteria for loss of fracture toughness due to the combined effects of TE and IE for CASS reactor RVI components, which would be consistent with the approach in MRP-227-A. This alternative would be based on ferrite content derived from certified material test reports for the CASS components. If applicants/licensees meet the screening criteria, a detailed analysis for CASS components would not be required to be submitted.

By letter dated January 28, 2014 (Ref. 33), the applicant provided plant-specific information on the ferrite content and susceptibility to TE of the column caps. Based on its evaluation of the plant-specific material information for the column caps, the applicant concluded that the IP2 and IP3 column caps are not susceptible to TE because the column caps are low molybdenum material (Type CF8) and all have ferrite content less than or equal to 20 percent, as calculated from the material chemical composition from the certified material test report for each material heat, using Hull's Formula (Hull's Equivalent Factors).

The staff developed updated criteria that take into account fracture toughness data on CASS subject to both thermal aging and neutron irradiation, as documented in Reference 34. The updated criteria allow screening for TE and IE of irradiated CASS components. According to the staff's updated criteria, low-molybdenum statically cast CASS with a ferrite content less than 15 percent can be screened out for TE and any synergistic effects of TE and IE, and is only susceptible to IE at fluences greater than 1×10^{21} n/cm^2 (1.5 dpa). This ferrite value represents a reduction in the ferrite content from the screening values from the staff's May 19, 2000, letter to accommodate possible combined effects. The ferrite content of the IP2 and IP3 column caps meets this criterion because all heats have calculated ferrite content less than 15 percent.

Therefore, the staff finds that the IP2 and IP3 lower core support column (column caps) are not susceptible to TE. Because of the neutron fluence of the upper portion of the column caps, the column caps are susceptible to IE, but not to any potential synergistic effect of TE and IE.

The staff evaluated the information provided by the applicant in its response to A/LAI 7, RAI 11, RAI 11-A, and RAI 11-B along with the supplementary ferrite content information. Based on the information on stress provided by the applicant, and the expected upper bound on neutron fluence for the columns, the staff finds that cracking due to IASCC is unlikely. Appendix B to MRP-175, "Materials Reliability Program: PWR Internals Material Aging Degradation Mechanism Screening and Threshold Values" (Ref. 25), also reported IASCC test data for CASS demonstrating extremely high resistance to IASCC. Therefore, the staff finds the applicant's determination of the low likelihood of IASCC to be reasonable based on the low operational stresses relative to the IASCC threshold for CASS and the high inherent IASCC resistance of this material. The applicant's CUF_{en} values indicate that fatigue crack initiation is not expected, and original manufacturing flaws are not expected because of the PT examinations performed during manufacturing. The information on ferrite content and material grade provides adequate justification to rule out a concern with TE for, or any synergistic effect of TE and IE on, the column caps. Although the upper portion of the column caps (within about 5 inches of the lower core plate) will receive neutron fluence sufficient for IE, this portion of the column cap should not have significant residual stress because it is remote from the weld. Apart from any weld residual stresses, the stresses on the column caps during normal operation should be compressive. Therefore, initiation or growth of cracks is unlikely during normal operation. Even if tensile stresses occur during a design basis accident, without a preexisting crack, column caps with reduced fracture toughness will not fracture.

The staff was concerned that the linked Primary component for the column caps, the CRGT assembly lower flange welds, is not a good predictor of IE for the column caps because the CRGT lower flange welds may receive substantially lower neutron fluence than the column caps (based on the estimated neutron fluence tabulated in MRP-191 for the two components). IASCC is the only mechanism of cracking that was screened in for the column caps. The CRGT lower flange welds are also not a good predictor for IASCC of the column caps, because the CRGT lower flange welds are susceptible to SCC and fatigue cracking, but not IASCC. Therefore, in RAI 11-C, the staff requested that the applicant modify the RVI Inspection Plan to provide a link to a Primary component or components that is an appropriate predictor of IE and IASCC of the column caps. In its August 5, 2014, response to RAI 11-C (Ref. 35), the applicant indicated that it would modify the RVI Inspection Plan to link the column caps as an Expansion component to the lower core barrel cylinder girth welds ("girth welds"). The response also stated that "[c]onsistent with existing guidance in MRP-227-A, confirmation of a surface crack greater than two inches in length will be taken as an indication of active cracking in the lower core barrel cylinder girth weld, and that "[t]his confirmation will require expansion of the inspection to the Indian Point lower support column bodies (column caps). The link between the CRGT lower flange welds and the lower support column bodies (column caps) provided in MRP-227-A remains unchanged." The response further stated that "…the "Expansion" inspection will be conducted within two refueling outages of the original observation of cracking in the lower core barrel cylinder girth weld." The applicant provided an extensive justification for the selection of the lower core barrel cylinder girth welds as the linked Primary component. The applicant's justification for the selection of the lower core barrel cylinder girth welds as an appropriate lead component for IE and IASCC is summarized by the staff as follows:

- The materials are similar in that austenitic stainless steel weld materials have a similar microstructure to low ferrite CASS materials.
- The operating temperatures are expected to be similar because both components are exposed to reactor coolant at core inlet temperature and have relatively small temperature increases due to gamma heating.
- The girth welds' predicted neutron fluence at the end of life is similar to that of the column caps. The peak fluence in the girth welds is predicted to be 2.51×10^{21} n/cm^2 (4 dpa) while the peak fluence in the column caps is predicted to be 4.11×10^{21} n/cm^2 (6 dpa), attenuating to 2.07×10^{21} n/cm^2 (3 dpa) within 1.6 inches below the lower core plate.
- Because material, temperature, and neutron fluence are relatively similar, stress is expected to be the dominant factor in determining which component is more susceptible to IASCC. The girth welds are expected to have higher tensile stresses because of weld residual stress while the column caps have primarily compressive stresses; therefore, the welds would have a higher IASCC susceptibility.

The applicant justified the scheduling of the Expansion inspection of the column caps within two refueling outages based on the following:

- It is reasonable to expect a significant delay in the onset of cracking in the column caps based on the difference in stress. Existing analysis of laboratory data indicates that large stresses are required to initiate IASCC at fluences below 10 dpa. The column caps are projected to be primarily in a compressive stress state; therefore, they are expected to have a higher threshold fluence for IE and IASCC than the core barrel.
- Completion of the Expansion inspection within two refueling outages (each fuel cycle is 24 months in duration) represents only 13 percent more than the approximately 32 effective full-power years of service experienced before the inspection of the core barrel cylinder girth weld. This provides reasonable assurance that IE and IASCC degradation, if any, will be detected in a timely fashion.

The applicant concluded that the fact that the IP2 and IP3 column caps are not susceptible to TE, combined with the addition of the new Primary link to an appropriate lead component for IE and IASCC, will assure functionality of the column caps during the period of extended operation. Therefore, the applicant deleted Commitment No. 47.

The staff notes that IASCC of the welds would be more likely to occur in the girth weld's heat-affected zone (HAZ) rather that the fusion zone of the weld. IASCC in the HAZ of austenitic stainless steel welds in RVI has been observed in BWRs but not in PWRs, while no IASCC has been noted in CASS RVI components in either BWRs or PWRs. Therefore, the staff considers IASCC more likely to occur in an austenitic stainless steel HAZ in a PWR than in a CASS component in a PWR.

The staff finds the applicant's selection of the lower core barrel cylinder girth welds as a Primary link for the column caps to be acceptable based on the following:

- The applicant demonstrated that the column caps and welds have similar material, neutron fluence, and temperature, while the welds are likely to have higher tensile stresses, which makes IASCC more likely to initiate in the welds. The susceptibility to IE depends primarily on fluence, which is similar for both components. IE alone cannot lead to failure without a mechanism for cracking, thus it is most important that the Primary component is an appropriate lead component for IASCC.
- The welds are subject to an EVT-1 visual examination, a technique which is capable of detecting tight cracks such as IASCC cracks.

The staff finds the applicant's proposal to conduct the Expansion inspection of the column caps within two refueling outages of the initial discovery of cracking in the welds to be acceptable because two refueling outages represents a relatively small percentage of the total lifetime of the columns, and the applicant justified that the stresses are estimated to be significantly lower in the column caps, which would result in lower IASCC susceptibility. The lower stresses would result in a longer time to initiate IASCC in the column caps compared to the welds, if IASCC were to start at all. For the maximum fluence of the column caps provided in the RAI 11-C response, the IASCC screening criteria from MRP-191 Table 3-2 would require a minimum stress of 70 ksi. The girth welds would be more likely to have localized residual tensile stresses exceeding this screening value than the column caps, which are subject to mainly compressive stresses during operation. In addition, the weld in the lower support columns is remote from the high fluence area of the column caps, so no tensile weld residual stresses are expected in the column caps. Further, the staff notes that for the original expansion from the CRGT lower flange weld to the column caps specified in MRP-227-A, the Expansion inspection of the column caps was required within three fuel cycles, compared to the two cycles proposed for the expansion from the lower core barrel cylinder girth welds. Therefore, the proposed schedule for expansion from the girth welds is more conservative than that of the recommended MRP-227-A Expansion inspection.

The staff finds that the applicant has adequately addressed A/LAI 7 based on the following: (1) The applicant evaluated the risk-significant CASS components of the RVI (the lower support columns (column caps)); (2) the applicant has screened the column caps for TE and IE using plant-specific materials data and determined that the column caps are not susceptible to TE (and the staff confirmed the results of the screening using its own screening criteria); (3) the applicant provided information on fabrication NDE demonstrating that pre-existing flaws are unlikely to exist in the column caps; (4) the applicant provided information on the expected stresses and neutron fluence for the column caps that demonstrated that service-induced cracking due to IASCC is unlikely; and (5) the applicant modified its RVI Inspection Program to include a link to a lead component that is an appropriate predictor of IASCC and IE for the column caps, with an appropriate schedule for performing the Expansion inspection if necessary. Therefore, the staff finds that the information provided by the applicant provides reasonable assurance that the functionality of the column caps will be maintained during the period of extended operation for IP2 and IP3, and deletion of Commitment 47 is acceptable. Based on this review, the staff's concerns in RAIs 11, 11-A, 11-B, and 11-C are resolved.

A/LAI 8

This action item specifies that applicants and licensees provide a submittal for NRC review and approval to credit their implementation of MRP-227-A as an AMP for the RVI components at their facilities. This action item states that the submittal shall include the information identified in Section 3.5.1 of staff's final SE for MRP-227, Revision 0.

Section 3.5.1 of Reference 9 states that in addition to the implementation of MRP-227, Revision 0, in accordance with NEI 03-08, applicants and licensees whose licensing basis contains a commitment to submit a PWR RVI AMP and/or inspection program shall also provide a submittal for NRC review and approval to credit their implementation of MRP-227, as amended by [the staff's final SE]. Section 3.5.1 of Reference 9 further states that an applicant's or licensee's application to implement MRP-227, as amended by the SE, shall include items (1) and (2) below, and that applicants who submit applications for license renewal after the issuance of the SE shall, in accordance with the GALL Report, Revision 2 (NUREG-1801), submit the information provided in the following items (1) through (5) for staff review and approval.

1. An AMP for the facility that addresses the 10 program elements defined in NUREG-1801, Revision 2, AMP XI.M16A.
2. To ensure that the MRP-227, Revision 0 program and the plant-specific action items will be carried out, applicants and licensees are to submit an inspection plan which addresses the identified plant-specific action items for staff review and approval consistent with the licensing basis for the plant. If an applicant or licensee plans to implement an AMP which deviates from the guidance provided in MRP-227, as approved by the NRC, the applicant or licensee shall identify where its program deviates from the recommendations of MRP-227, as approved by the NRC, and shall provide a justification for any deviation which includes a consideration of how the deviation affects both Primary and Expansion inspection category components.
3. The regulation at 10 CFR 54.21(d) requires that an FSAR supplement for the facility contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation. Those applicants for LR citing MRP-227, as approved by the staff, for their RVI component AMP shall ensure that the programs and activities specified as necessary in MRP-227, as approved by the NRC, are summarily described in the FSAR supplement.
4. The regulation at 10 CFR 54.22 requires each applicant for LR to submit any TS changes (and the justification for the changes) that are necessary to manage the effects of aging during the period of extended operation as part of its LRA. For the plant CLBs that include mandated inspection or analysis requirements for RV internals either in the operating license for the facility or in the facility TS, the applicant or licensee shall compare the mandated requirements with the recommendations in the NRC-approved version of MRP-227. If the mandated requirements differ from the recommended criteria in MRP-227, as approved by the NRC, the conditions in the applicable license conditions or TS requirements take precedence over the MRP recommendations and shall be complied with.
5. Under 10 CFR 54.21(c)(1), the applicant is required to identify all analyses in the CLB for its RVI components that conform to the definition of a TLAA in 10 CFR 54.3 and shall identify these analyses as TLAAs for the application in accordance with the TLAA identification requirement in 10 CFR 54.21(c)(1). MRP-227, as approved by the NRC,

does not specifically address the resolution of TLAAs that may apply to applicant or licensee RVI components. Hence, applicants and licensees who implement MRP-227, as approved by the NRC, shall still evaluate the CLB for their facilities to determine whether they have plant-specific TLAAs that shall be addressed. If so, the applicant's or licensee's TLAA shall be submitted for NRC review along with the applicant's or licensee's application to implement the NRC-approved version of MRP-227.

For those cumulative usage factor (CUF) analyses that are TLAAs, the applicant may use the PWR Vessel Internals Program as the basis for accepting these CUF analyses in accordance with 10 CFR 54.21(c)(1)(iii) only if the RVI components in the CUF analyses are periodically inspected for fatigue-induced cracking in the components during the period of extended operation. The periodicity of the inspections of these components shall be justified to be adequate to resolve the TLAA. Otherwise, acceptance of these TLAAs shall be done in accordance with either 10 CFR 54.21(c)(1)(i) or (ii), or in accordance with 10 CFR 54.21(c)(1)(iii) using the applicant's program that corresponds to the GALL Report, Revision 2, AMP X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary Program." To satisfy the evaluation requirements of ASME Code Section III, Subsections NG-2160 and NG-3121, the existing fatigue CUF analyses should include the effects of the reactor coolant system water environment.

The staff notes that, according to the wording of A/LAI 8, because the IP2 and IP3 LRA was submitted before the issuance of the staff's final SE for MRP-227, the applicant would only be required to submit the information for Items (1) and (2). However, because the IP2 and IP3 renewed licenses have not been issued yet, the staff evaluated the applicant's compliance with Items (1) through (5).

<u>Item 1</u>

Applicant Evaluation

With respect to Item 1 of A/LAI 8, the applicant stated that a description of the IPEC RVI AMP was included in Amendment 9 to the License Renewal Application (NL-10-063, July 14, 2010) (Ref. 1). The applicant further stated that the AMP description has been revised to be consistent with MRP-227-A and that the revised AMP description has been submitted under letter NL-12-037 (Ref. 5). The applicant stated that this document comprises an inspection plan which addressed the identified plant-specific action items contained in Revision 1 to the [NRC staff's] Final Safety Evaluation for MRP-227, and that IPEC is not requesting any deviations from the guidance provided in MRP-227-A.

Staff Evaluation

The staff notes that, by letter dated July 14, 2010 (Ref. 1), as amended by letter dated February 17, 2012 (Ref. 5), the applicant provided a completely new Section B.1.42 of the LRA consisting of the RVI Program, which addresses the 10 AMP attributes. The staff's evaluation of the AMP's 10 program elements is found in Section 3.0.3.3.9 of this SER supplement. On the basis of its review, the staff finds that the applicant has provided the necessary information to satisfy Item 1.

Item 2

Applicant Evaluation

The applicant stated in Attachment 2 to its February 17, 2012, letter that [Attachment 2 to its February 17, 2012, letter] comprises an inspection plan which addresses the identified plant-specific action items contained in Revision 1 of the NRC Final Safety Evaluation for MRP-227. The applicant also stated that IPEC is not requesting any deviations from the guidance provided in MRP-227-A.

Staff Evaluation

The applicant's February 17, 2012, letter (Ref. 5) addresses Item 2 of A/LAI 8 because it includes the RVI Inspection Plan which addresses the applicable plant-specific A/LAIs. Therefore, the staff finds that the applicant has provided the necessary information to satisfy Item 2.

Item 3

Applicant Evaluation

In its February 17, 2012, letter (Ref. 5), the applicant provided revised FSAR Sections A.2.1.41 (for IP2) and A.3.1.41 (for IP3), both titled "RVI Aging Management Activities," which provide a summary of the RVI Program. The summary explains that the RVI Program is based on MRP-227-A and MRP-228. The FSAR section also indicated that the RVI Program will be implemented in accordance with Addendum A to NEI 03-08.

Staff Evaluation

Section 3.0.3.3.9.4 contains the staff's evaluation of the revised FSAR sections. The staff finds that the applicant has provided the necessary information to satisfy Item 3.

Item 4

Applicant Evaluation

The applicant did not identify any TS changes related to the RVI Program.

Staff Evaluation

The staff examined the TS for IP2 and IP3 and verified that there are no TS surveillance requirements that would conflict with the requirements of MRP-227-A. Therefore, the staff finds that the applicant has provided the necessary information to address Item 4.

Item 5

Applicant Evaluation

The applicant did not identify any new TLAAs related to RVI in Reference 5.

Staff Evaluation

Entergy's identification of TLAAs was approved by the staff in the SER (Ref. 8).

In its response to A/LAI 8, the applicant stated that the RVI AMP description has been revised to be consistent with MRP-227-A and that IPEC's response to A/LAI 8 does not request any deviations from the guidance provided in MRP-227-A.

LRA Section 4.3.1.2 provides the applicant's TLAA and associated CUF values for the IP2 and IP3 RVI. The staff noted that, in Amendment 3 to the LRA dated March 24, 2008 (Ref. 36), the applicant amended LRA Section 4.3.1.2 to state that "fatigue on the RVI will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii) for both IP2 and IP3." In Section 4.3.1.2 of the SER, the staff concluded that the applicant has demonstrated, under 10 CFR 54.21(c)(1)(iii), that, for the RVI, the effects of aging on the intended function(s) would be adequately managed for the period of extended operation.

A/LAI 8 also indicates that the Fatigue Monitoring Program may be used as the basis for accepting CUF analyses in accordance with 10 CFR 54.21(c)(1)(iii), in which case the evaluation requirements of ASME Code Section III Section NG are to be satisfied.

Neither the LRA, nor the SER, nor the applicant's response to A/LAI 8 addresses whether the CUF analyses for the RVI satisfied the requirements of Subsections NG-2160 and NG-3121 of Section XI of the ASME Code related to the effects of the reactor water environment. Therefore, in RAI 12 the staff requested clarification with respect to whether the applicant will use its RVI Program, its Fatigue Monitoring Program, or a combination of both to manage fatigue of the RVI during the period of extended operation. If the RVI Program is to be used as a basis for managing fatigue of any RVI components with CUF analyses, the staff requested information on the examination methods and frequency and a justification showing that the frequency is adequate. If the Fatigue Monitoring Program will be used, the staff requested that the applicant verify that the requirements of ASME Code Section III, Subsections NG-2160 and NG-3121, as delineated in A/LAI 8, will be satisfied.

In its response to RAI 12, by letter dated June 14, 2012, the applicant indicated that, for RVI components that are not covered by a TLAA analysis, IPEC will use the RVI Program to manage the effects of aging due to fatigue on the RVI. The applicant stated that, as provided in Section 3.5.1 of the NRC's SE for MRP-227-A for locations with a fatigue TLAA, IPEC will manage the effects of aging due to fatigue through the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii).

The applicant further stated in its RAI 12 response that the Fatigue Monitoring Program as described in LRA Section B.1.12 provides assurance that the CUF remains below the allowable limit of 1.0 and that, to be consistent with Section 3.5.1 of the SE for MRP-227-A, the existing RVI fatigue calculations will be reviewed before the units enter the period of extended operation to evaluate the effects of the reactor coolant system water environment on the CUF. The applicant further stated that, specifically, under Commitment No. 43, Entergy would review the IPEC design basis ASME Code Class 1 fatigue evaluations to determine whether the locations identified in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," 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. Finally, the applicant stated that this review includes ASME Code Class 1 fatigue evaluations for RVI, and that if more limiting locations are identified, the most limiting location will be evaluated for the effects of the reactor coolant environment on fatigue usage.

In RAI 15, the staff requested that the applicant (1) clarify whether the review described in the response to RAI 12 will include CUF calculations for the RVI that incorporate environmental factors (F_{en}); (2) clarify what action will be taken if the consideration of environmental effects results in a CUF exceeding 1.0 for any RVI component; (3) clarify the meaning of the term "ASME Code Class 1 fatigue evaluations" because, technically, this term only applies to reactor coolant pressure boundary components (ASME Class 1 rules do not cover RVI components); (4) provide a new commitment and UFSAR supplement to address the review of RVI for environmentally assisted fatigue as part of the Fatigue Monitoring Program in response to A/LAI 8 of the staff's SE for MRP-227-A, in lieu of the proposal to use Commitment No. 43.

In its October 17, 2012, response to RAI 15 (Ref. 37), the applicant revised its response to RAI 12 to indicate that it intends to use the RVI Program to manage the cumulative fatigue damage aging effect for RVI components that have a TLAA analysis that determined a CUF. The staff had a number of concerns with the applicant's description of how it intended to use RVI Program to manage fatigue of RVI components. Among the staff's concerns were that (1) inspections might never be required for Expansion components subject to fatigue unless degradation is found in the linked Primary component; (2) the adequacy of the periodicity of the RVI inspections (generally 10 years) might not be adequate to manage fatigue cracking; and (3) some components susceptible to fatigue cracking are "No Additional Measures" components and so have no specified examination techniques, periodicity, coverage, or acceptance criteria under MRP-227-A. Therefore, the staff issued followup RAI 15-A requesting that the applicant clarify how these issues would be addressed.

In its May 7, 2013, response to RAI 15-A (Ref. 30), the applicant stated that it would rely on the Fatigue Monitoring Program to manage the effects of fatigue on the RVI during the period of extended operation rather than the RVI Program as previously indicated in the original response to RAI 15. The applicant also provided a revised response to RAI 15, which indicated that the CUFs for the limiting RVI components would be recalculated using F_{en} factors provided in NUREG/CR-5704, "Effects of LWR Coolant Environments on the Fatigue Design Curves of Austenitic Stainless Steels," for stainless steel components or NUREG/CR-6909, "Effects of LWR Coolant Environments on the Fatigue of Reactor Materials," for nickel-based alloy components. In response to the staff's request that the applicant clarify what actions will be taken if the consideration of environmental effects results in a CUF_{en} exceeding 1.0, the applicant stated that corrective actions would include further CUF reanalysis and/or repair or replacement of the affected components before the CUF_{en} reaches 1.0. The applicant also clarified that the term "Class 1" was inadvertently included in the response to RAI 12 and that the phrase "ASME Code Class 1 fatigue evaluations for reactor vessel internals" is changed to read "ASME Code Subsection NG fatigue evaluations for reactor vessel internals." The applicant also provided a new commitment (Commitment No. 49) to recalculate the CUF values to include reactor coolant environmental effects and take corrective actions if necessary, as described above. The applicant also included a revised list of regulatory commitments providing the new Commitment No. 49 and showing an implementation schedule of before September 28, 2013, for IP2 and before December 12, 2015 for IP3 (i.e., before the start of the period of extended operation for both units). The applicant also provided a markup of the UFSAR supplement sections A.2.2.2 and A.3.2.2 for "Class 1 Metal Fatigue."

By letter dated July 26, 2013, the staff issued RAI 15-B, requesting that the applicant revise UFSAR Supplement Sections A.2.2.2 and A.3.2.2 for consistency with its response to RAI 15-A. In its response to RAI 15-B dated September 27, 2013 (Ref. 12), the applicant revised LRA Sections A.2.2.2 and A.3.2.2 to include new subsections A.2.2.2.3 and A.3.2.2.3 for "Subsection NG Fatigue Analysis of Reactor Pressure Vessel Internals," which contain a description of the methodology described in the response to RAI 15-A, and also include the commitment dates for completing these analyses. The applicant also deleted the discussion of RVI from LRA Sections A.2.2.2.1 and A.3.2.2.1, "Class 1 Metal Fatigue." The staff finds these revisions acceptable.

The staff finds the applicant's response to RAI 15-A technically acceptable because the methods proposed for managing fatigue of the RVI are consistent with those allowed by A/LAI 8 from MRP-227-A. Specifically, the applicant will use its Fatigue Monitoring Program to manage fatigue of RVI, and will consider the effects of the reactor coolant environment on fatigue. Additionally, the cited sources for the F_{en} factors to correct for the effects of the environment are consistent with those that are acceptable according to the GALL Report, Revision 2, Section X.M.1, "Fatigue Monitoring." The staff's concerns in RAIs 12, 15, 15-A, and 15-B are thus resolved.

Summary—A/LAI 8

Based on the above, the staff finds that the applicant has provided the information required by A/LAI 8, Items (1) through (5).

Conditions from Safety Evaluation of MRP-227, Revision 0. The conditions from Revision 1 of the final SE for MRP-227, Revision 0, address changes the staff required to be made in the final approved version of the topical report (MRP-227-A). Because MRP-227-A had not been issued at the time that the applicant prepared the initial version of its RVI Inspection Plan, in Table 5-8 of the RVI Inspection Plan the applicant provided a brief description of how each condition is addressed in the RVI Inspection Plan. The staff reviewed the applicant's resolution of each of these conditions.

Staff Evaluation

Condition 1—This condition required moving several components from the No Additional Measures inspection category to the Expansion inspection category. The applicable components for Westinghouse-designed RVI are the upper core plate and the lower support forging or casting. This condition did not change from Revision 0 to Revision 1 of the SE. The staff verified that the IPEC RVI Inspection Program incorporates this change.

Condition 2—This condition required changing the inspection category of several components from Expansion to Primary. The applicable components for Westinghouse-designed RVI are the upper and lower core barrel girth welds and the lower core barrel flange weld. The staff notes that the component description was changed from "all upper and lower core barrel welds" in Revision 0 of the staff's SE to only "the girth welds" in Revision 1 of the staff's SE. The staff verified that the IPEC RVI Inspection Program incorporates this change.

Condition 3—This condition does not apply to components in Westinghouse-designed reactors, so it is not applicable.

Condition 4—This condition required (a) the minimum examination coverage to be defined as 75 percent of the total accessible and inaccessible area or volume or (b) when addressing a set of like components, that the inspection examine a minimum sample size of 75 percent of the total population of like components in the Expansion category. The staff verified that the examination coverage specified in Table 5-3 of the IPEC RVI Inspection Program for Expansion components meets this condition.

Condition 5—As applicable to Westinghouse-designed RVI, this condition required that the examination frequency of baffle-former bolts be changed from "10 to 15 years" to "10 years." The staff verified that Table 5-2 of the IPEC RVI Inspection Program meets this condition.

Condition 6—This condition required a baseline 10-year reexamination interval to be applied to all Expansion components once (a) degradation is identified in the associated Primary inspection category components and (b) examination of the Expansion category component begins, unless the applicant or licensee provides an evaluation to the staff justifying a longer interval between inspections. The staff verified that Table 5-3 of the IPEC RVI Inspection Program incorporates this condition.

Condition 7—This condition required the inclusion of a reference to RVI AMP XI.M16A in the GALL Report, Revision 2 in Appendix A to MRP-227-A. As such, this condition does necessitate changes in the IPEC RVI Inspection Plan or AMP.

The staff finds that all conditions applicable to Westinghouse-designed RVI have been incorporated in the inspection and evaluation requirements for IP2 and IP3.

Summary—Action Items and Conditions from Safety Evaluation of MRP-227, Revision 0

Based on the information evaluated in this section, the staff finds that the applicant has adequately addressed all of the A/LAIs and conditions described in the staff's final SE for MRP-227, Revision 0 (Ref. 9), that are applicable to IP2 and IP3.

Staff's Evaluation of the RVI Inspection Plan's Consistency with MRP-227-A. In addition to its review of the A/LAIs, the staff reviewed the information provided in IPEC's RVI Inspection Plan for general consistency with MRP-227-A. Section 1.0 of MRP-227-A is the executive summary, so it is not specifically addressed below.

Background (Section 2.0 of MRP-227-A)

Section 2.0 of MRP-227-A contains general background, a discussion of the scope, and applicability information.

The staff verified that the scope of the applicant's RVI Inspection Plan is consistent with that described in MRP-227-A Section 2.0 (i.e., is limited to the RVI structural components). Section 2.0 of the RVI Inspection Plan provides significant detail on the items within the scope of the plan. The applicability information of Section 2.4 of MRP-227-A is addressed in detail in Section 3.0.3.3.10.3.1 of this SSER under the discussion of A/LAI 1.

Component Categorization and Aging Management Strategy Development (Section 3.0 of MRP-227-A)

This section of MRP-227-A provides information on the RVI design characteristics for the three different nuclear steam supply system (NSSS) designs, an overview of the applicable degradation mechanisms and effects, and a description of the process used to develop the aging management strategy recommendations of MRP-227-A, including screening for degradation mechanisms, categorization, and FMECA.

In Section 2.0 of the RVI Inspection Plan, the applicant provided a description of the design of the IP2 and IP3 internals. This section also provides verbal descriptions and figures showing the general arrangement and specific subcomponents of the generic Westinghouse-designed RVI. The figures are consistent with those included in MRP-227-A. The description of the upper internals assembly provided in the IPEC RVI Inspection Plan is similar to that provided in MRP-227-A Section 3.1.3, and notes that the upper support plate (USP) design at IPEC is designated as a “top hat” design. The description of the lower internals assembly is also similar to the corresponding description in MRP-227-A, with some plant-specific information added. For example, the description notes that at IPEC, corner brackets are installed behind and bolted to the baffle plates.

Section 3.1 of the RVI Inspection Plan summarizes the guidance of the MRP I&E Guidelines necessary to understand the implementation of MRP-227-A but does not duplicate the full discussion of the technical bases. Because the end result of the process described in Section 3 of MRP-227-A is the categorization of the components and inspection and evaluation recommendations for the various inspection categories, the consistency of the applicant’s program with these results can be evaluated by assessing the consistency of the aging management requirements specified in the applicant’s RVI Program with MRP-227-A. The aging management requirements in the IPEC RVI Program were found to be consistent with MRP-227-A, as documented in Section 3.0.3.3.9 of this SER Supplement.

Based on the above, the staff finds that the RVI Inspection Plan is consistent with the information provided in Section 3 of MRP-227-A with respect to the component categorization and aging management strategy development.

Aging Management Requirements (Section 4.0 of MRP-227-A)

This section of MRP-227-A provides tables describing the recommended inspections (technique, schedule of initial and subsequent inspections, and inspection coverage) for RVI components in the Primary, Expansion, and Existing Programs categories. The staff confirmed that the information in Tables 5-2, 5-3, and 5-4 of the RVI Inspection Plan is consistent with that in Tables 4-3 (Primary), 4-6 (Expansion), and 4-9 (Existing Programs) in MRP-227-A.

Examination Acceptance Criteria and Expansion Requirements (Section 5.0 of MRP-227-A)

Table 5-3 of MRP-227-A provides the acceptance criteria for the Primary and Expansion category components of Westinghouse-designed RVI and the Expansion criteria defining when the inspection results for the Primary components trigger inspections of the Expansion components. The staff checked the corresponding information in Table 5-5 of the RVI Inspection Plan and finds it to be consistent with the information in Table 5-3 of MRP-227-A.

Evaluation Methodologies (Section 6.0 of MRP-227-A)

This section of MRP-227-A provides recommended flaw evaluation methods to be used when the examinations recommended in Section 4.0 reveal relevant conditions. The applicant did not include any information in the RVI Inspection Plan addressing evaluation methodologies. However, as noted in the staff's evaluation of IPEC's RVI AMP in Section 3.0.3.3.9 of this SER supplement, the applicant stated that it would apply the evaluation methodologies of Section 6.0 of MRP-227-A or other NRC-approved evaluation methods in the description of the "corrective action" program element.

In addition, in the staff's final SE for MRP-227, Revision 0, the staff noted that in an RAI response, EPRI stated that (a) topical report WCAP-17096-NP is the document that will be used as the framework to develop the generic and plant-specific evaluations triggered by findings in the RVI examinations and (b) the staff is currently reviewing WCAP-17096-NP, Revision 2. Therefore, in RAI 4, the staff requested that the applicant address the use of WCAP-17096-NP, Revision 2, as the basis for the methods to be used to evaluate relevant inspection findings. The applicant's response to RAI 4 is evaluated in Section 3.0.3.3.9.1 of this SER supplement.

Implementation Requirements (Section 7.0 of MRP-227-A)

Section 7 of MRP-227 provides a summary of the implementation requirements established by the nuclear industry for the guidelines described in MRP-227. The implementation requirements are defined by the latest edition of NEI 03-08, which includes implementation categories used in MRP-227 such as: (a) "Mandatory," which requires implementation of the guidelines at all plants; (b) "Needed," which provides an option for implementing the guidelines wherever possible or implementing alternative approaches, or (c) "Good Practice," which recommends implementation of the guidelines as an option whereby significant operational and reliability benefits can be achieved at a given plant. Failure to meet a "Needed" or a "Mandatory" requirement is a deviation from the guidelines and a written justification for deviation must be prepared and approved as described in Appendix B to NEI 03-08. A copy of the deviation is sent to the MRP so that, if needed, improvements to the guidelines can be developed. A copy of the deviation is also sent, for information, to the NRC. Section 7 of MRP-227 specified the following with respect to the implementation of specific MRP-227 guidelines:

1. Each PWR unit shall develop and document an AMP for the PWR RVI components within thirty-six months following the issuance of MRP-227-A. This is a "Mandatory" requirement.
2. Each PWR unit shall implement Tables 4-1 through 4-9 and Tables 5-1 through 5-3 of MRP-227 for the applicable design within twenty-four months following the issuance of MRP-227-A. This is a "Needed" requirement.
3. Examination of the RVI components shall comply with the MRP-228 Revision 0, "Materials Reliability Program: Inspection Standard for PWR Internals." This is a "Needed" requirement.
4. Examination results that do not meet the examination acceptance criteria defined in Section 5 of the MRP-227 guidelines shall be recorded and entered in the plant corrective action program and dispositioned. This is a "Needed" requirement.
5. A summary report of all inspections and monitoring, evaluation, and new repairs shall be provided within one hundred and twenty days of the completion of an outage during

which the RVI components were examined. The summary of the examination results shall be included in an industry report that is updated every six months. This report will monitor the industry progress on the AMP related to PWR RVI components and it will also list the emerging operating experience. This is a "Good Practice" requirement.

6. If an engineering evaluation is used to disposition an examination result that does not meet the examination acceptance criteria in Section 5, this engineering evaluation shall be conducted in accordance with a NRC-approved evaluation methodology. This is a “Needed” requirement.

Because IPEC has developed and documented its AMP for RVI components through the submittal of LRA Amendment 9, as modified by its February 17, 2012, letter (Ref. 5), and this has occurred within 36 months of the issuance of MRP-227-A, the applicant has met the mandatory requirements. The information provided in Section 4.4 of the RVI Inspection Plan is consistent with the “Needed” and “Good Practice” requirements of Items 2 through 6 above. Therefore, the staff finds that the implementation requirements for the RVI Inspection Plan are consistent with the implementation requirements defined in MRP-227-A and are thus acceptable.

Staff’s Evaluation of Consistency between the LRA and the RVI Inspection Plan. The staff compared the information in Tables 5-2, 5-3, and 5-4 of the RVI Inspection Plan to the information included in Tables 3.1.2-2-IP2 and 3.1.2-2-IP3 of the LRA, as amended by LRA Amendment 9, which provide the summary of the aging management review for IP2 and IP3. Any component that credits the RVI AMP in these tables should be included in either Table 5-2 or Table 5-3 of the RVI Inspection Plan, which contain the inspection requirements for the Primary and Expansion components for IP2 and IP3. Because Tables 5-2 and 5-3 of the RVI Inspection Plan use the component nomenclature from MRP-227-A (which differs from the IP2 and IP3 plant-specific nomenclature used in LRA Tables 3.1.2-2-IP2 and 3.1.2-2-IP3), Table 5-1 of the RVI Inspection Plan provided a cross-index between the LRA and MRP-227-A nomenclature. The staff found that all of the components crediting the RVI AMP in LRA Tables 3.1.2-2-IP2 and 3.1.2-2-IP3 are included in Tables 5-2 and 5-3 of the RVI Inspection Plan. In addition, the staff compared LRA Tables 3.1.2-2-IP2 and 3.1.2-2-IP3 for consistency with Table 5-4 of the RVI Inspection Plan, which identifies the applicant’s Existing Program components corresponding to Table 4-9 of MRP-227-A. This review identified some apparent inconsistencies between the RVI Inspection Plan’s Table 5-4, “Existing Program Components at IPEC Units 2 and 3,” and Tables 3.1.2-2-IP2 and 3.1.2-2-IP3 with respect to the existing program (AMP) credited with managing the aging effect. Specifically, for the flux thimble guide tubes and clevis insert bolts at IPEC, the Water Chemistry Program—Primary and Secondary is assigned to manage loss of material in Tables 3.1.2-2-IP2 and 3.1.2-2-IP3, while in Table 5-4 of the RVI Inspection Plan, different programs are listed as the existing program managing loss of material for these components. Therefore, in RAI 13, the staff requested that the applicant clarify these apparent inconsistencies.

In its October 17, 2012, response to RAI 13 (Ref. 37), the applicant clarified these apparent inconsistencies, noting that in the IPEC license renewal aging management review, the flux thimble tubes (and the flux thimble guide tubes external to the reactor vessel) were evaluated as part of the reactor vessel and the aging management review results were presented in LRA Tables 3.1.2-1-IP2 and -IP3. The applicant further indicated that as a consequence, the “Bottom Mounted Instrumentation System—Flux thimble tubes” listed in Table 5-4 of the RVI Inspection Plan are the same as the “Bottom mounted instrumentation—flux thimble tubes” listed in LRA Tables 3.1.2-1-IP2 and -IP3. The applicant stated that (a) these LRA tables identify “loss of material—wear” as an applicable aging effect and identify the “Flux Thimble

Tube Inspection Program" as the AMP and (b) this is consistent with Table 5-4 of the RVI Inspection Plan. Finally, the applicant stated that the LRA table line items (in Tables 3.1.2-2-IP2 and 3.1.2-2-IP3) that indicate loss of material managed by the Water Chemistry—Primary and Secondary Program refer to loss of material due to pitting and crevice corrosion, not by wear. The staff notes that loss of material due to pitting and crevice corrosion for the flux thimble tubes is not identified as an AERM in MRP-227-A, so it is acceptable for the applicant to identify a different AMP to manage loss of material due to this mechanism. The staff reviewed the applicant's identified AMP for the flux thimble tubes against the recommendation of MRP-227-A. Table 4-9 of MRP-227-A cites the GALL Report, Revision 1, as the source of the AMP requirements, surface examination by eddy current testing as the examination method, and eddy current surface examination as described in the plant response to Bulletin 88-09 as the required examination coverage. GALL Report, Revision 1, Table IV.B2, identifies the recommended AMP for the flux thimble tubes as the "Flux Thimble Tube Inspection Program" described in Section XI.M37 of the GALL Report, Revision 1. Consistent with the GALL Report, Revision 1, LRA Tables 3.1.2-1-IP2 and 3.1.2.1-IP3 identify the "Flux Thimble Tube Inspection Program" as the applicable AMP for managing loss of material due to wear. In the SER (Ref. 8), the staff found that the applicant's "Flux Thimble Tube Inspection Program" was consistent (with enhancements) with the GALL Report, Revision 1, and that the effects of aging would thus be adequately managed. Therefore, the applicant's AMP for the flux thimble tubes is acceptable because it is consistent with both the recommendations of the GALL Report, Revision 1, and MRP-227-A, Table 4-9.

In LRA Tables 3.1.2-2-IP2 and -IP3, loss of material due to wear was identified as an aging effect for the clevis inserts, but not for the clevis insert bolts. In its October 17, 2012, response to RAI 13, the applicant stated that this is consistent with the GALL Report, Revision 1, which does not identify an aging effect of loss of material due to wear for the bolts. The applicant further stated that MRP-227-A identifies loss of material due to wear as an aging effect for the clevis insert bolts and that the RVI Inspection Plan manages this aging effect accordingly. The applicant stated that the LRA table line items for clevis insert bolts that indicate loss of material managed by the Water Chemistry—Primary and Secondary Program refer to loss of material due to pitting and crevice corrosion, not by wear. Finally, the applicant stated that, for consistency with MRP-227-A and the RVI Inspection Plan, the following line item would be added to LRA Tables 3.1.2-2-IP2 and -IP3. The staff finds this response acceptable because the applicant modified the AMP in the LRA which manages loss of material due to wear of the clevis insert bolts for consistency with MRP-227-A, which identifies the bolts as Existing Programs components with wear managed by the Inservice Inspection Program.

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Lower internals assembly • clevis insert bolt	Structural support	Nickel alloy	Treated borated water	Loss of material – wear	Inservice Inspection	--	--	H

The staff finds the applicant's response to RAI 13 acceptable because it has clarified or corrected the apparent inconsistencies between LRA Tables 3.1.2-2-IP2 and -IP3 and Table 5-4 of the RVI Inspection Plan, demonstrating that the aging management of the Bottom Mounted Instrumentation System—flux thimble tubes and the clevis insert bolts will be consistent with MRP-227-A. The Staff's concern in RAI 13 is therefore resolved.

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

3.1 Aging Management of Reactor Coolant System

3.1.1 Summary of Technical Information in the Application

By letter dated July 14, 2010, the applicant submitted Amendment 9 to its LRA to include the RVI AMP. The applicant removed its previous commitment to submit a reactor vessel internals inspection program and, as a result, it made several changes to the LRA.

3.1.2 Staff Evaluation

The abbreviated Table 3.1-1, below, summarizes the staff's evaluation of components, aging effects, and AMPs in light of the changes associated with the RVI Program. Columns 1 through 5 represent the applicant's statements in the amended LRA. References to the staff's evaluation are provided in Column 6.

Table 3.1-1. Staff Evaluation for Reactor Vessel, Reactor Vessel Internals, and Reactor Coolant System Components in the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel alloy reactor vessel internals components exposed to reactor coolant and neutron flux (3.1.1-22)	Loss of fracture toughness due to neutron irradiation embrittlement, void swelling	FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.	No, but licensee commitment needs to be confirmed	Reactor Vessel Internals Program	See SER Section 3.1.2.2.6

Component Group (GALL Report Item No.)	Aging Effect/Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel alloy reactor vessel internals screws, bolts, tie rods, and hold-down springs (3.1.1-27)	Loss of preload due to stress relaxation	FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.	No, but licensee commitment needs to be confirmed	Reactor Vessel Internals Program	See SER Section 3.1.2.2.9
Stainless steel reactor vessel internals components (e.g., upper internals assembly, RCCA guide tube assemblies, baffle/former assembly, lower internal assembly, shroud assemblies, plenum cover and plenum cylinder, upper grid assembly, control rod guide tube (CRGT) assembly, core support shield assembly, core barrel assembly, lower grid assembly, flow distributor assembly, thermal shield, instrumentation support structures) (3.1.1-30)	Cracking due to SCC, irradiation-assisted SCC	Water Chemistry and FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval less than 24 months before the extended period an RVI inspection plan based on industry recommendation.	No, but licensee commitment needs to be confirmed	Reactor Vessel Internals Program	See SER Section 3.1.2.2.12

Component Group (GALL Report Item No.)	Aging Effect/Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel alloy reactor vessel internals components (3.1.1-33)	Changes in dimensions due to void swelling	FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval less than 24 months before the extended period an RVI inspection plan based on industry recommendation.	No, but licensee commitment needs to be confirmed	Reactor Vessel Internals Program	See SER Section 3.1.2.2.15
Stainless steel and nickel alloy reactor vessel internals components (e.g., upper internals assembly, RCCA guide tube assemblies, lower internal assembly, CEA shroud assemblies, core shroud assembly, core support shield assembly, core barrel assembly, lower grid assembly, flow distributor assembly) (3.1.1-37)	Cracking due to SCC, PWSCC, irradiation-assisted SCC	Water Chemistry and FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.	No, but licensee commitment needs to be confirmed	Water Chemistry Control – Primary and Secondary and either the Reactor Vessel Internals Program or the Inservice Inspection Program (for the lower core plate only)	See SER Section 3.1.2.2.17
Steel reactor vessel flange, stainless steel and nickel alloy reactor vessel internals exposed to reactor coolant (e.g., upper and lower internals assembly, CEA shroud assembly, core support barrel, upper grid assembly, core support shield assembly, lower grid assembly) (3.1.1-63)	Loss of material due to wear	Inservice Inspection (IWB, IWC, and IWD)	No	Inservice Inspection and the Reactor Vessel Internals Program	See SER Section 3.1.2.1.11

In LRA Amendment 9, the “Discussion” column in LRA Table 3.1.1, “Summary of Aging Management Programs of the Reactor Coolant System Evaluated in Chapter IV of NUREG-1801,” was changed to replace wording referring to the commitment to implement the industry program in Sections A.2.1.4.1 and A.3.1.4.1 of Appendix A to the UFSAR Supplement with a reference to the RVI Program. In LRA Tables 3.1.2-2-IP2 and 3.1.2-2-IP3, “Reactor Vessel Internals, Summary of Aging Management Review,” the information for components aligned with the line items listed in LRA Table 3.1.1 in the “Aging Management Programs” column is changed from “RVI Commitment” to “Reactor Vessel Internals.”

The line items listed above in LRA Table 3.1.1 are all line items pertaining to RVI components for which, according to Table 1 in Volume 1 of Revision 1 of the GALL Report, the need for further evaluation is waived if the applicant’s commitment to implement the RVI Program developed by industry is confirmed. Table 1 in Volume 1 of Revision 1 of the GALL Report described the commitment as follows: “FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.” The original IP2 and IP3 LRA included a commitment consistent with this wording for the items listed in the table above.

The staff finds the changes to the “Discussion” column information in LRA Table 3.1.1 and the changes to the assigned AMP in LRA Tables 3.1.2-2-IP2 and 3.1.2-2-IP3 to be acceptable because the changes reflect the replacement of the commitment to implement the RVI Program consistent with the program developed by industry, with the actual RVI Program. In addition, the staff notes that in LR-ISG-2011-04 none of these components would require further evaluation.

The staff reviewed the changes to LRA Table 3.1.1 in LRA Amendment 9 and concludes that the changes are acceptable because the items now cite the RVI Program rather than a commitment. Based on the staff’s review of the changes of the listed line items, the effects of aging for the affected RVI components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

Detailed evaluation of these changes can be found in SER Sections 3.1.2.2.6, 3.1.2.2.9, 3.1.2.2.12, 3.1.2.2.15, and 3.1.2.2.17.

3.1.2.1.10 Aging Effects Requiring Management for RVI Components

In LRA Amendment 9, the applicant revised Tables 3.1.2.2-IP2 and 3.1.2.2-IP3, both entitled “RVI Summary of Aging Management Review.” The major change to these tables is in the “Aging Management Programs” column, where “RVI commitment” has been replaced with “Reactor Vessel Internals.” This change reflects a change from crediting the commitment to implement the industry program when it was completed, tracked by Commitment No. 30, to crediting the new RVI AMP described in LRA Section B.1.42 with management of aging for the AERMs applicable to the IP2 and IP3 RVI. The other notable change to these tables is the replacement of generic note “A” with generic note “E” wherever the RVI AMP was credited. Generic note “A” reads, “Consistent with NUREG-1801 item for component, material, environment, aging effect and AMP is consistent with NUREG-1801 AMP.” Generic note “E” reads “Consistent with NUREG-1801 material, environment, and aging effect but a different AMP is credited.” The change from generic note A to generic note E reflects the fact that citing the RVI commitment is consistent with the GALL Report, Revision 1, while citing the RVI AMP is not consistent with the GALL Report, Revision 1. However, crediting the RVI Program is consistent with LR-ISG-2011-04, which updates the guidance in Revision 2 of the GALL Report to reflect MRP-227-A and thus contains the most current guidance acceptable to the staff for managing aging of RVI. Other changes include changes to some component types and addition of some completely new line items. These changes are consistent with the changes in the scoping and screening information evaluated in Section 2.3.1.2 of this SER supplement. For some components, AMPs other than the RVI AMP are credited with managing certain AERMs. For example, the Water Chemistry Control—Primary and Secondary AMP is credited with managing the AERM “loss of material” for several components. These AERMs continue to cite generic note “A” because the component, material, environment, aging effect, and AMP are consistent with the GALL Report, Revision 1.

The component, material, environment, and aging effect information is consistent with the GALL Report, Revision 1, which was the most current NRC guidance at the time these changes were submitted, although slightly different component terminology is used in some cases. The AMP credited for managing aging is consistent with LR-ISG-2011-04, which updates the GALL Report, Revision 2, guidance to reflect MRP-227-A and thus contains the most current guidance acceptable to the staff for managing aging of RVI, with two exceptions. First, the “Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program” is credited for managing reduction of fracture toughness for the “lower internals assembly – lower core support castings – column cap – lower core support column bodies (column caps),” whereas LR-ISG-2011-04 specifies the RVI Program. The relationship between the “Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program” and the RVI AMP was clarified in the applicant’s September 28, 2012, response to RAI 10, which is discussed in more detail in SER Section 3.0.3.3.10. The staff’s review of the applicant’s RVI Inspection Plan, detailed in SER Section 3.0.3.3.10, confirmed that the MRP-227-A aging management recommendations for the column caps will be met. Second, the ISI Program is credited for managing aging of several components. All of the components for which the ISI Program is credited for managing aging effects are classified as Existing Programs components within MRP-227-A; the ASME Code Section XI ISI Program is the existing program credited for managing aging of these components in Table 4-9 of MRP-227-A. Therefore, there is no effective discrepancy with LR-ISG-2011-04. Further, in its review of the RVI AMP detailed in SER Section 3.0.3.3.9, the staff verified that the IPEC RVI Inspection Plan implements all of the Existing Programs inspections of MRP-227-A. Therefore, the two apparent exceptions to LR-ISG-2011-04 have been reconciled and determined to result in equivalent aging management to the criteria of LR-ISG-2011-04.

Based on the above, the staff finds the changes to LRA Tables 3.1.2.2-IP2 and 3.1.2.2-IP3 acceptable because component, material, environment, and aging-effect information is consistent with the GALL Report, Revision 1, and the credited AMPs are consistent with the most current NRC guidance for RVI aging management in LR-ISG-2011-04, with two exceptions that were determined by the staff to be equivalent with the criteria of LR-ISG-2011-04.

In the LRA, for several aging effects applicable to the RVI, the applicant credited Commitment No. 30 for fulfilling the further evaluation requirements. Commitment No. 30 states: “For aging management of the RVI, IPEC will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; (3) on completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval." The "further evaluation" sections affected are:

3.1.2.2.6 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement and Void Swelling

3.1.2.2.9 Loss of Preload Due to Stress Relaxation

3.1.2.2.12 Cracking Due to Stress Corrosion Cracking and Irradiation-Assisted Stress Corrosion Cracking

3.1.2.2.15 Changes in Dimensions Due to Void Swelling

3.1.2.2.17 Cracking Due to Stress Corrosion Cracking, Primary Water Stress Corrosion Cracking, and Irradiation-Assisted Stress Corrosion Cracking

In LRA Amendment 9, the listed LRA sections were revised to credit the RVI Program in place of Commitment No. 30. The following sections evaluate the changes to the listed LRA sections and are intended to replace the previous SER sections in their entirety. The staff notes, in the LRA sections listed above provided in LRA Amendment 9, the applicant cited MRP-227 rather than MRP-227-A. Because the applicant did not cite the staff approved version of MRP-227, in RAI 2 the staff requested the applicant update the reference to MRP-227-A. In its response to RAI 2 by letter dated June 14, 2012, the applicant provided revisions of the LRA sections listed above changing the references to MRP-227-A. Therefore, RAI 2 is resolved.

3.1.2.2.6 Loss of Fracture Toughness due to Neutron Irradiation Embrittlement and Void Swelling

By letter dated July 14, 2010, Entergy amended LRA Section 3.1.2.2.6 to remove its previous commitment. In response to RAI 2 by letter dated June 14, 2012, Entergy revised LRA Section 3.1.2.2.6 to state that "The RVI Program will implement the EPRI Pressurized Water Reactor Internals Inspection and Evaluation Guidelines, MRP-227-A. The RVI Program will use nondestructive examinations (NDE) and other inspection methods to manage aging effects for reactor vessel internals."

The staff's evaluation of the applicant's program to address this aging effect is documented in SER Section 3.0.3.3.9.

3.1.2.2.9 Loss of Preload due to Stress Relaxation

By letter dated July 14, 2010, Entergy amended LRA Section 3.1.2.2.9 to remove its previous commitment. In response to RAI 2 by letter dated June 14, 2012, Entergy revised LRA Section 3.1.2.2.9 to state that "The RVI Program will implement the EPRI Pressurized Water Reactor Internals Inspection and Evaluation Guidelines, MRP-227-A. The RVI Program will use nondestructive examinations (NDE) and other inspection methods to manage aging effects for reactor vessel internals."

The staff's evaluation of the applicant's program to address this aging effect is documented in SER Section 3.0.3.3.9.

3.1.2.2.12 Cracking Due to Stress Corrosion Cracking and Irradiation-Assisted Stress Corrosion Cracking

By letter dated August 22, 2011 (Ref. 38), Entergy amended LRA Section 3.1.2.2.12 to remove its previous commitment and to state that "[c]racking due to SCC and IASCC in PWR stainless steel reactor internals exposed to reactor coolant will be managed by the Water Chemistry Control—Primary and Secondary and the Reactor Vessel Internals (RVI) Programs."

In its June 14, 2012, response to RAI 3, Entergy further amended LRA Section 3.1.2.2.12 to state that:

> Cracking due to SCC and IASCC in PWR stainless steel reactor internals exposed to reactor coolant will be managed by the Water Chemistry Control—Primary and Secondary Program and the Reactor Vessel Internals (RVI) or Inservice Inspection (ISI) Programs. The RVI program will implement the EPRI Pressurized Water Reactor Internals Inspection and Evaluation Guidelines, MRP-227-A. The RVI Program will use nondestructive examinations (NDE) and other inspection methods to manage aging effects for reactor vessel internals. The RVI Program includes inspections of core support structures using the existing ASME Section XI, ISI Program as delineated in MRP-227-A, Table 4-9. Where credited for the management of cracking, the existing ISI Program is listed in Tables 3.1.2-2-1P2 and 3.1.2-2-1P3 in lieu of the RVI Program.

In RAI 3, the staff requested that the applicant justify the use of the ISI Program to manage cracking. In its June 14, 2012, response to RAI 3, the applicant justified its use of the ISI Program to manage the aging effect of cracking for the "Upper Support Plate, Support Assembly (Including Ring)" on the basis that this component is categorized as an Existing Programs component by MRP-227-A, with the ISI Program identified as the existing program in Table 4-9 of MRP-227-A. The staff notes that in Tables 3.1.2-2-1P2 and 3.1.2-2-1P3, the ISI Program is also assigned to manage cracking of the "Lower Internals Assembly—Lower Core Plate," which is also an Existing Programs component in MRP-227-A. For Existing Programs components defined in MRP-227-A that rely on the ISI Program, the staff found in its final SE for MRP-227, Revision 0 (Ref. 9), that the inspections specified by the ISI Program are adequate to manage the aging effect of cracking. Therefore, the staff finds that crediting the ISI Program with managing cracking of the "Upper Support Plate, Support Assembly (Including Ring)" and the "Lower Internals Assembly—Lower Core Plate" is acceptable because the ISI Program is adequate to manage cracking in this component. The staff's evaluation of the applicant's ISI Program is documented in the SER (Ref. 8)," Section 3.0.3.3.4.

The staff finds the applicant's proposal to use the Water Chemistry Control Program (Primary and Secondary) to be acceptable for managing cracking due to SCC and IASCC of stainless steel RVI components because the Water Chemistry Control Program (Primary and Secondary) will control contaminants that can contribute to SCC of stainless steel. The staff's evaluation of the applicant's Water Chemistry Control Program is documented in Section 3.0.3.2.17 of the SER (Ref. 8).

In addition, the staff notes that LR-ISG-2011-14, "Updated Aging Management Criteria for Reactor Vessel Internal Components for Pressurized Water Reactors" (Ref. 7), updates the GALL Report, Revision 2, guidance to reflect MRP-227-A and thus contains the most current guidance acceptable to the staff for managing aging of RVI. Use of the RVI Program AMP and Water Chemistry AMP to manage SCC and IASCC of RVI is consistent with the guidance in

LR-ISG-2011-14 Section XI.M16A. Under "Preventive Actions," LR-ISG-2011-14 states that MRP-227-A relies on PWR water-chemistry control to prevent or mitigate aging effects that can be induced by corrosive aging mechanisms (e.g., loss of material induced by general, pitting corrosion, crevice corrosion, or stress corrosion cracking or any of its forms [SCC, PWSCC, or IASCC]), and that reactor coolant water chemistry is monitored and maintained in accordance with the Water Chemistry Program as described in GALL AMP XI.M2, "Water Chemistry." The applicant's use of the ISI Program to manage cracking due to SCC and IASCC is equivalent to use of the RVI Program for the components in question because MRP-227-A specifies the ISI Program as the existing program credited for inspection for cracking of these components. Therefore, the applicant's use of the RVI Program, ISI Program, and Water Chemistry Control Program is consistent with the staff's most current guidance for aging management of RVI.

The staff therefore finds the applicant's use of the combination of the RVI Program, ISI Program, and Water Chemistry Control Program (Primary and Secondary) to be acceptable because (1) the RVI Program and ISI Program will detect cracking due to SCC and IASCC, the Water Chemistry Program will mitigate SCC by minimizing contaminants, and (3) use of these programs is consistent with or equivalent to the staff's most current guidance for aging management of RVI.

The staff's evaluation of the applicant's RVI Program is documented in Section 3.0.3.3.9 of this SER supplement.

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

3.1.2.2.15 Changes in Dimensions due to Void Swelling

By letter dated July 14, 2010, Entergy amended LRA Section 3.1.2.2.15 to remove its previous commitment. In response to RAI 2 by letter dated June 14, 2012, Entergy revised LRA Section 3.1.2.2.15 to state that "[t]he RVI Program will implement the EPRI Pressurized Water Reactor Internals Inspection and Evaluation Guidelines, MRP-227-A. The RVI Program will use nondestructive examinations (NDE) and other inspection methods to manage aging effects for reactor vessel internals."

The staff's evaluation of the applicant's program to address this aging effect is documented in SER Section 3.0.3.3.9.

3.1.2.2.17 Cracking due to Stress Corrosion Cracking, Primary Water Stress Corrosion Cracking, and Irradiation-Assisted Stress Corrosion Cracking

By letter dated July 14, 2010, Entergy amended LRA Section 3.1.2.2.17 to remove its previous commitment. In response to RAI 2 by letter dated June 14, 2012, Entergy revised LRA Section 3.1.2.2.17 to state that "[t]he RVI Program will implement the EPRI Pressurized Water Reactor Internals Inspection and Evaluation Guidelines, MRP-227-A. The RVI Program will use nondestructive examinations (NDE) and other inspection methods to manage aging effects for reactor vessel internals."

The staff's evaluation of the applicant's program to address this aging effect is documented in SER Section 3.0.3.3.9.

The staff noted that the applicant proposes to use the Inservice Inspection Program, in addition to the Water Chemistry Control—Primary and Secondary Program, to manage cracking of the stainless steel lower internals assembly—lower core plate. The GALL Report, Revision 1, recommends Water Chemistry and a commitment to implement the RVI Program. The Inservice Inspection program is credited for managing aging of several components. All of the components for which the Inservice Inspection Program is credited are classified as "Existing Programs" components within MRP-227-A; the ASME Code Section XI Inservice Inspection Program is the existing program credited with managing aging of the lower core plate in Table 4-9 of MRP-227-A. Further, in its review of the RVI Program, detailed in SER Section 3.0.3.3.9, the staff verified that the RVI Inspection Plan implements all of the "Existing Programs" inspections specified in MRP-227-A. Based on its review of the stainless steel lower core plate, the staff finds the applicant's proposal to manage cracking due to IASCC using the Inservice Inspection Program acceptable because the applicant will perform the visual inspections required by ASME Code Section XI and these visual inspections are capable of detecting cracking.

3.1.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

3.1.2.3.2 Reactor Vessel Internals—Summary of Aging Management Review

By letter dated October 17, 2012, the applicant amended LRA Tables 3.1.2-2-IP2 and 3.1.2-2-IP3 to add nickel-alloy clevis insert bolts which are exposed to treated borated water and will be managed for loss of material due to wear by the Inservice Inspection Program.

The staff's evaluation of this component, material, environment, and aging effect is documented in SER Section 3.0.3.3.10.

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

3.2.1 Summary of Technical Information in the Application

There are no changes or updates to this section of the SER.

3.2.2 Staff Evaluation

There are no changes or updates to this section of the SER.

3.2.2.1 AMR Results Consistent with the GALL Report

LRA Tables 3.2.2-1-IP2 through 3.2.2-5-IP2 and 3.2.2-1-IP3 through 3.2.2-5-IP3 summarize the results of AMRs for the auxiliary system components and indicate AMRs that are claimed to be consistent with the GALL Report.

Since the issuance of Supplement 1 to the SER (SSER 1), Entergy has amended the LRA in annual updates to the LRA or in response to requests for additional information (RAIs).

The staff reviewed the information in the amendments to the LRA. The staff verified that the material presented in the amendments to the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs.

The staff reviewed the amendments 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 revisions noted above and found that the additional AMR results are consistent with the GALL Report for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified and that the aging effects listed are appropriate for the combination of materials and environments identified.

The staff also reviewed an AMR item that cited generic note D in error and an item that cited generic note E. The staff evaluated whether all plausible aging effects were identified and whether the aging effects listed were appropriate for the combination of materials and environments specified. Details of the staff's evaluation are discussed in Section 3.2.2.1.5.

3.2.2.1.5 Loss of Material Due to General Corrosion

By letter dated September 26, 2012, the applicant amended LRA Table 3.4.2.5-7-IP2 to include carbon steel filter housings exposed externally to indoor air and will be managed for loss of material by the External Surfaces Monitoring Program. These items cite LRA Table 3.2-1, item 3.2.1-32 and generic note E. The staff noted that item 3.2.1-32 is associated with an internal indoor air environment. Item 3.2.1-32 in SRP-LR Table 3.2-1 recommends GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to manage loss of material for steel piping and ducting components and internal surfaces exposed to air - indoor uncontrolled. However, these items are exposed externally to indoor air. GALL Report item A-80 recommends that steel piping components exposed externally to indoor air should be managed for loss of material by the External Surfaces Monitoring Program. The staff finds the applicant's use of the External Surfaces Monitoring Program acceptable because it is consistent with the GALL Report.

By letter dated September 26, 2013, the applicant amended LRA Table 3.3.2-13-IP2 by adding carbon steel piping and filter housings and gray cast iron turbochargers which are exposed internally to indoor air and will be managed for loss of material. These AMR items, which cite LRA Table 3.2 1, item 3.2.1-32, and generic note E, credit the External Surfaces Monitoring Program. However, by letter dated December 12, 2013, the applicant removed these line items from the scope of license renewal because it had re-evaluated the CLB and determined that it no longer relies on the black start diesel (GT3-BSD), so it removed from the scope of license renewal all previously included components associated with GT3-BSD.

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

3.2.2.2.4 Reduction of Heat Transfer Due to Fouling

(1) By letter dated September 26, 2012, the applicant amended LRA Table 3.4.2-5-13-IP2 by adding copper alloy greater than 15 percent zinc (inhibited) heat exchanger tubes

which are exposed externally to lubricating oil, and will be managed for fouling. This AMR item, which cites item 3.2.1-9 and generic note D and plant-specific note 316, credits the Oil Analysis Program and the One-Time Inspection Program. The staff's evaluation of this material, environment, aging effect, and program combination is documented in SER Section 3.2.2.2.4, item (1).

3.2.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

There are no changes or updates to this section of the SER.

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

3.3.1 Summary of Technical Information in the Application

There are no changes or updates to this section of the SER.

3.3.2 Staff Evaluation

There are no changes or updates to this section of the SER.

3.3.2.1 AMR Results Consistent with the GALL Report

LRA Tables 3.3.2-1-IP2 through 3.3.2-18-IP2, 3.3.2-1-IP3 through 3.3.2-18-IP3, 3.3.2-19-1-IP2 through 3.3.2-19-44-IP2, and 3.3.2-19-1-IP3 through 3.3.2-19-65-IP3 summarize the results of AMRs for the auxiliary system components and indicate AMRs that are claimed to be consistent with the GALL Report.

Since the issuance of SSER 1, Entergy has amended the LRA in annual updates to the LRA or in response to requests for additional information (RAIs).

The staff reviewed the information in the amendments to the LRA. The staff verified that the material presented in the amendments to the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs.

The staff reviewed the amendments 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.

By letter dated December 20, 2011, the applicant submitted an annual update to the LRA, identifying changes made to the CLB that materially affect the contents of the LRA. For the IP2 nitrogen system, the applicant revised LRA Table 3.3.2-5-IP2 to delete AMR entries for a stainless steel flow element exposed internally to gas with an aging effect of "none" and exposed externally to indoor air with an aging effect of "none." Additionally, the applicant revised LRA Table 3.3.2-3-IP3 to add a stainless steel flow element exposed internally to treated water with an aging effect of "loss of material" and exposed externally to indoor air with an aging effect of "none," and generic notes A and B.

By letter dated September 26, 2012, the applicant submitted an update to its LRA which amended LRA tables associated with the auxiliary feedwater pump room fire event. The applicant identified changes during an extent-of-condition review that resulted from the discovery of previously provided information that was either incorrect or omitted from the LRA. The applicant amended LRA tables associated with LRA Section 3.3 to add components made of carbon steel and copper alloy exposed to indoor air or outdoor air.

By letter dated December 27, 2012, 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 made of stainless steel, carbon steel, copper alloy with greater than 15 percent zinc, gray cast iron, copper alloy, and aluminum bronze exposed to indoor air, treated water, treated borated water greater than 140 °F, raw water, and fuel oil.

By letter dated September 26, 2013, the applicant submitted a partial annual update to the LRA, identifying changes made to the CLB that materially affect the contents of the LRA. The applicant amended LRA Table 3.3.2-13-IP2 for the fuel oil system to add components made of stainless steel, carbon steel, copper alloy greater than 15 percent zinc, gray cast iron, and aluminum exposed to indoor air or treated water. By letter dated December 12, 2013, the applicant removed these components from the scope of license renewal because it had re-evaluated the CLB and determined that it no longer relied on the black start diesel (GT3-BSD), so it removed from the scope of license renewal all previously included components associated with GT3-BSD.

By letter dated December 12, 2013, 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 made of stainless steel and copper alloy with greater than 15 percent zinc exposed to indoor air, treated water, treated borated water, and treated borated water greater than 140 °F. The AMR items cite generic notes A and C.

The staff reviewed the applicant's revisions noted above and found that the additional AMR results are consistent with the GALL Report for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified and that the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.2.1.12 Loss of Material due to General, Pitting and Crevice Corrosion

By letter dated October 18, 2012, the applicant amended LRA Tables 3.3.2-2-IP3, 3.3.2-13-IP2 and 3.3.2-13-IP3 by adding carbon steel piping which is externally exposed to condensation and will be managed for loss of material. These AMR items, which cite LRA Table 3.3.1, items 3.3.1-58 and 3.3.1-60 and generic note E, credit the Buried Piping and Tanks Inspection Program to manage the aging effect for these components. The GALL Report recommends GALL Report AMP XI.M36, "External Surfaces Monitoring," to assure that these aging effects are adequately managed. GALL Report AMP XI.M36 recommends using periodic external visual examinations to manage aging.

The staff's evaluation of the applicant's Buried Piping and Tanks Inspection Program is documented in SER Section 3.0.3.1.2. In its letter dated October 18, 2012, the applicant stated that portions of the IP3 service water, IP3 city water, and IP2 and IP3 fuel oil systems are located in vaults or pipe trenches.

Based on its review of components associated with items 3.3.1-58 and 3.3.1-60, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging of underground piping using the Buried Piping and Tanks Inspection Program acceptable because (a) although the piping is not coated, the applicant has significantly increased the frequency of inspections, to every 2 years versus every 10 years as recommended in LR-ISG-2011-03; (b) the applicant is inspecting all of the underground piping instead of two percent of the pipe as recommended in LR-ISG-2011-03; (c) the visual inspections before the period of extended operation and those conducted during the period of extended operation are capable of detecting loss of material before the intended function of the piping not being met; and (d) the inspection frequencies would not be revised to every 10 years as recommended by LR-ISG-2011-03 unless the piping is coated.

The staff concludes that for LRA Items 3.3.1-58 and 3.3.1-60, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

By letter dated September 26, 2012, the applicant amended LRA Table 3.4.2-5-13-IP2 by adding gray cast iron valve bodies which are exposed to indoor air (external) and will be managed for loss of material by the External Surfaces Monitoring Program. These items cite LRA Table 3.3 1, item 3.3.1-14, generic note D, and plant-specific note 316. Item 3.3.1-14 in SRP-LR Table 3.3 1 is used for steel piping, piping components, and piping elements exposed to lubricating oil. The staff recognizes that the applicant used the wrong table 1 line item; nevertheless, GALL Report item A-80 (SRP-LR item 3.3.1-57) states that gray cast iron valve bodies exposed to indoor air (external) should be managed for loss of material by the External Surfaces Monitoring Program. The staff finds the applicant's use of the External Surfaces Monitoring Program acceptable because it is consistent with the GALL Report.

By letter dated September 26, 2012, the applicant amended LRA Table 3.4.2-5-7-IP2 by adding carbon steel piping and valve bodies which are exposed to condensation (internal) and will be managed for loss of material. These AMR items, which cite item 3.3.1-71 and generic note E, credit the Periodic Surveillance and Preventive Maintenance Program. The GALL Report recommends GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to assure that these aging effects are adequately managed. GALL Report AMP XI.M38 recommends periodic opportunistic visual inspections to detect loss of material.

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 noted that the Periodic Surveillance and Preventive Maintenance Program proposes to manage the aging of carbon steel piping and valve bodies through the use of periodic visual examinations (conducted every 5 years) to detect loss of material for a representative population of each material and environment combination. The staff also noted that the program permits increasing the inspection's sample size if aging effects are detected. Unacceptable inspection findings are evaluated in accordance with the corrective action process to determine the need for accelerated inspection frequency and for monitoring and trending the results. Based on its review of these components, the staff finds the applicant's proposal to manage aging using the Periodic Surveillance and Preventive Maintenance Program acceptable because (a) periodic visual inspections are performed which are capable of detecting loss of material; (b) the inspection sample size is increased if aging effects are detected, providing reasonable assurance that aging effects can be detected if they are occurring in other components; and (c) inspection findings are evaluated through the corrective action process, assuring that the intended functions of these components will be maintained consistent with the CLB for the period of extended operation.

3.3.2.1.13 Loss of Material due to General and Pitting Corrosion

By letter dated September 26, 2012, the applicant amended LRA Table 3.4.2-5-13-IP2 by adding gray cast iron compressor housings and carbon steel silencers which are exposed to internal condensation and will be managed for loss of material. These AMR items, which cite item 3.3.1-53 and generic note E, credit the Periodic Surveillance and Preventive Maintenance Program. The GALL Report recommends GALL Report AMP XI.M24, “Compressed Air Monitoring,” to assure that these aging effects are adequately managed. The staff’s evaluation of loss of material due to general and pitting corrosion for steel compressed-air system piping, piping components, and piping elements exposed to condensation (internal) being managed by the Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.3.2.1.3. However, gray cast iron is known to be susceptible to selective leaching in certain environments. It was not clear to the staff whether sufficient condensation could accumulate in the compressor housing to cause selective leaching. By letter dated June 12, 2013, the staff issued RAI 3.4.2.1.9-1 requesting that the applicant provide clarification about whether sufficient condensation could accumulate in any portions of the gray cast iron compressor and strainer housings to such a degree that selective leaching could occur, and if selective leaching could occur, how the aging effect would be managed. In its response dated July 24, 2013, the applicant stated that the gray cast iron compressor and strainer housing in Table 3.4.2-5-13-IP2 have a drain trap system to prevent accumulation of condensation. The applicant also stated that selective leaching in a condensation environment has not been observed at Indian Point.

The staff finds the response to RAI 3.4.2.1.9-1 acceptable because drain traps are capable of preventing an accumulation of condensation, and if condensation does not accumulate, selective leaching will not occur.

The staff’s concern described in RAI 3.4.2.1.9-1 is resolved.

3.3.2.1.14 Loss of Material due to Pitting and Crevice Corrosion

By letter dated September 26, 2012, the applicant amended LRA Tables 3.4.2-5-7-IP2 and 3.4.2-5-7-IP2 by adding stainless steel tubing, valve bodies, dryer housings, filter housings, and aluminum valve bodies which are exposed to condensation (internal) and will be managed for loss of material. The AMR items, which cite item 3.3.1-54 and generic note E, credit the One-Time Inspection Program. The staff’s evaluation of loss of material for stainless steel piping and piping components exposed to condensation being managed by the One-Time Inspection Program is documented in SER Section 3.3.2.1.3. The addition of aluminum valve bodies does not alter the staff’s evaluation because pitting and crevice corrosion can be as effectively detected in aluminum components as in stainless steel.

3.3.2.1.15 No Aging Effect Requiring Management

By letter dated September 26, 2012, the applicant amended LRA Table 3.4.2-5-7-IP2 by adding aluminum valve bodies exposed to indoor air (external) and treated air (internal), citing LRA Table 3.3.1, item 3.3.1-54. These items have no AERM and no recommended AMP. The staff finds the applicant's proposal acceptable because GALL Report items TP-8, EP-3, and AP-36 recommend no AERM or AMP for aluminum exposed to indoor air (external) and treated air (internal).

3.3.2.1.16 Loss of Material due to General Corrosion

By letter dated September 26, 2012, the applicant amended LRA Table 3.4.2-5-7-IP2 by adding carbon steel filter housings which are exposed to indoor air (internal) and will be managed for loss of material by the Periodic Surveillance and Preventive Maintenance Program. These items cite LRA Table 3.3 1, item 3.3.1 57, and generic note A. The SRP LR states that loss of material for this material and environment combination should be managed by GALL Report AMP XI.M36, "External Surfaces Monitoring." GALL Report AMP XI.M36 recommends using periodic visual inspections at least once per refueling cycle to manage loss of material.

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 Periodic Surveillance and Preventive Maintenance Program proposes to manage the aging of carbon steel filter housings through the use of periodic visual inspections, which are conducted at least once every 5 years. The staff noted that the program permits increasing the inspection's sample size if aging effects are detected. The staff also noted that unacceptable inspection findings are evaluated in accordance with the corrective action process to determine the need for accelerated inspection frequency and for monitoring and trending the results. Based on its review of these components, the staff finds the applicant's proposal to manage aging using the Periodic Surveillance and Preventive Maintenance Program acceptable because (a) periodic visual inspections are performed which are capable of detecting loss of material; (b) the inspection sample size is increased if aging effects are detected, providing reasonable assurance that aging effects can be detected if they are occurring in other components; and (c) inspection findings are evaluated by the corrective action process, assuring that the intended functions of these components will be maintained consistent with the CLB for the period of extended operation.

3.3.2.1.17 Loss of Material due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion, Fouling, and Lining/Coating Degradation

By letter dated September 26, 2012, the applicant amended LRA Table 3.4.2-5-5-IP2 by adding gray cast iron piping and valve bodies which are exposed to raw water (internal) and will be managed for loss of material. These AMR items, which cite item 3.3.1-76 and generic note E, credit the Periodic Surveillance and Preventive Maintenance Program. The GALL Report recommends GALL Report AMP XI.M20, "Open Cycle Cooling Water System," to assure that these aging effects are adequately managed. GALL Report AMP XI.M20 recommends periodic visual inspections to detect loss of material.

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 noted that the Periodic Surveillance and Preventive Maintenance program proposes to manage the aging of gray cast iron piping and valve bodies through the use of periodic visual examinations (which are conducted at least once every 5 years) to detect loss of material for a representative population of each material and environment combination. The staff also noted that the program permits increasing the inspection's sample size if aging effects are detected. The staff further noted that unacceptable inspection findings are evaluated in accordance with the corrective action process to determine the need for accelerated inspection frequency and for monitoring and trending the results. Based on its review of these components, the staff finds the applicant's proposal to manage aging using the Periodic Surveillance and Preventive Maintenance Program acceptable because (a) periodic visual inspections are performed which are capable of detecting loss of material; (b) the inspection sample size is increased if aging effects are detected, providing reasonable assurance that aging effects can be detected if they are occurring in other components; and (c) inspection findings are evaluated by the corrective action process, assuring that the intended functions of these components will be maintained consistent with the CLB for the period of extended operation.

3.3.2.1.18 Loss of Material Due to Pitting, Crevice, Galvanic, and Microbiologically-Influenced Corrosion, and Fouling

By letter dated September 26, 2012, the applicant amended LRA Table 3.3.2-19-13-IP2 by adding copper alloy heat exchanger bonnets which are exposed to raw water (internal) and will be managed for loss of material. This AMR item, which cites item 3.3.1-82 and generic note E, credits the Periodic Surveillance and Preventive Maintenance Program. The GALL Report recommends GALL Report AMP XI.M20, "Open Cycle Cooling Water System," to assure that these aging effects are adequately managed. GALL Report AMP XI.M20 recommends periodic visual inspections to detect loss of material.

The staff's evaluation of the applicant's Periodic Surveillance and Preventative Maintenance Program is documented in SER Section 3.0.3.3.7. The staff noted that the Periodic Surveillance and Preventative Maintenance Program proposes to manage the aging of copper alloy heat exchanger bonnets through the use of periodic visual inspections which are conducted at least once every 5 years. The staff noted that the program permits increasing the inspection's sample size if aging effects are detected. The staff also noted that unacceptable inspection findings are evaluated in accordance with the corrective action process to determine the need for accelerated inspection frequency and for monitoring and trending the results. Based on its review of these components, the staff finds the applicant's proposal to manage aging using the Periodic Surveillance and Preventive Maintenance Program acceptable because (a) periodic visual inspections are performed which are capable of detecting loss of material; (b) the inspection sample size is increased if aging effects are detected, providing reasonable assurance that aging effects can be detected if they are occurring in other components; and (c) inspection findings are evaluated by the corrective action process, assuring that the intended functions of these components will be maintained consistent with the CLB for the period of extended operation.

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

3.3.2.2.5 Hardening and Loss of Strength Due to Elastomer Degradation

(1) By letter dated September 26, 2012, the applicant amended LRA Table 3.4.2-5-2-IP2 by adding elastomer expansion joints which are exposed to air-indoor (external) and will be managed for cracking and change in material properties. This AMR item, which cites item 3.3.1-11 and generic note E, credits the Periodic Surveillance and Preventive

Maintenance Program. The GALL Report recommends further evaluation of a plant-specific AMP to assure that these aging effects are adequately managed. The staff's evaluation of this material, environment, aging effect, and program combination is documented in SER Section 3.3.2.2.5, Item (1).

3.3.2.2.7 Loss of Material Due to General, Pitting, and Crevice Corrosion

(1) By letter dated September 26, 2012, the applicant amended LRA Table 3.4.2-5-13-IP2 by adding carbon steel filter housings, piping, pump casings, tanks, and carbon steel and gray cast iron valve bodies which are internally exposed to lubricating oil and will be managed for loss of material. This AMR item, which cites item 3.3.1-14, generic note D, and plant-specific note 316, credits the Oil Analysis and the One-Time Inspection Programs. The staff's evaluation of this material, environment, aging effect, and program combination is documented in SER Section 3.3.2.2.7, Item (1).

(3) By letter dated September 26, 2013, the applicant amended LRA Table 3.3.2-13-IP2 to add stainless steel flexible bellows and carbon steel piping and silencers which are exposed internally to exhaust gas and will be managed for loss of material. These AMR items, which cite item 3.3.1-18, credit the Periodic Surveillance and Preventive Maintenance Program. However, by letter dated December 12, 2013, the applicant removed these line items from the table because it had re-evaluated the CLB and determined that it no longer relies on the black start diesel (GT3-BSD), so it removed from the scope of license renewal all previously included components associated with the black start diesel.

3.3.2.2.9 Loss of Material Due to General, Pitting, Crevice, Microbiologically-Influenced Corrosion and Fouling

(2) By letter dated September 26, 2012, the applicant amended LRA Table 3.4.2-5-13-IP2 by adding carbon steel heat exchanger shells which are exposed to lubricating oil and will be managed for loss of material. This AMR item, which cites item 3.3.1-21, generic note D, and plant-specific note 316, credits the Oil Analysis and One-Time Inspection Programs. The staff's evaluation of this material, environment, aging effect, and program combination is documented in SER Section 3.3.2.2.9, Item (2). The staff noted that in its September 26, 2012, amendment, the applicant did not address fouling as an applicable aging effect for this material and environment combination. However, the staff finds that the visual one-time inspections for loss of material are equally capable of detecting fouling.

3.3.2.2.10 Loss of Material Due to Pitting and Crevice Corrosion

(3) By letter dated September 26, 2012, the applicant amended LRA Table 3.4.2-5-9-IP2 by adding copper alloy valve bodies which are exposed to condensation (external) and will be managed for loss of material. By letter dated December 27, 2012, the applicant submitted an annual update to its LRA, identifying changes to the CLB that materially affect the LRA. For the IP3 service water system, the applicant revised LRA Table 3.3.2-2-IP3 to add an AMR item for aluminum bronze pump casing exposed externally to condensation. These AMR items, which cite item 3.3.1-25 and generic note E, credit the External Surfaces Monitoring Program. The GALL Report recommends a plant-specific AMP to detect loss of material.

The staff's evaluation of the applicant's External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.5. The staff noted that the External Surfaces Monitoring Program proposes to manage the aging of components through the use of periodic visual inspections. A visual inspection is conducted for component surfaces at least once per refueling cycle. The intervals of inspections may be adjusted as necessary based on plant-specific inspection results and industry experience. Based on its review of these components associated with item 3.3.1-25, the staff finds the applicant's proposal to manage aging using the External Surfaces Monitoring Program acceptable because visual inspections which are capable of detecting loss of material are conducted for component surfaces at least once per refueling cycle.

(4) By letter dated September 26, 2012, the applicant amended LRA Table 3.4.2-5-9-IP2 by adding copper alloy with greater than 15 percent zinc (inhibited) heat exchanger tubes which are exposed to lubricating oil (external) and will be managed for loss of material. This AMR item, which cites item 3.3.1-26, generic note D, and plant-specific note 316, credits the Oil Analysis Program and the One-Time Inspection Program. The staff's evaluation of this material, environment, aging effect, and program combination is documented in SER Section 3.3.2.2.10, Item (4). The staff noted that the SER evaluation was associated with copper alloy components, whereas these items are composed of copper alloy with greater than 15 percent zinc (inhibited). The aging effects for copper alloy and copper alloy with greater than 15 percent zinc (inhibited) are the same based on the definition of "copper alloy greater than 15 percent zinc" in GALL Report Section IX.C, "Selected Definitions and Use of Terms for Describing and Standardizing Materials."

(5) By letter dated September 26, 2012, the applicant amended LRA Table 3.4.2-5-9-IP2 by revising the material designation of the carbon steel nozzles to stainless steel nozzles; these are exposed to condensation (external) and will be managed for loss of material. This AMR item, which cites item 3.3.1-27 and generic note E, credits the External Surfaces Monitoring Program. The GALL Report recommends a plant-specific AMP to detect loss of material. The staff's evaluation of this material, environment, aging effect, and program combination is documented in SER Section 3.3.2.2.10, Item (5).

(6) By letter dated September 26, 2012, the applicant amended LRA Tables 3.4.2-5-7-IP2 and 3.4.2-5-13-IP2 by adding copper alloy and copper alloy with greater than 15 percent zinc tubing, valve bodies, and heat exchanger tubes which are exposed to condensation (internal) and will be managed for loss of material. These AMR items, which cite item 3.3.1-28 and generic note E, credit the Periodic Surveillance and Preventive Maintenance Program. The staff's evaluation of this material, environment, aging effect, and program combination is documented in SER Section 3.3.2.2.10, Item (6).

3.3.2.3 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

<u>Plastic piping exposed internally to raw water and externally to indoor air</u>. By letter dated September 26, 2013, the applicant amended LRA Table 3.3.2-2-IP2 by adding plastic piping exposed to raw water (internally) and indoor air (externally). For the internal piping surfaces exposed to raw water, the applicant stated that changes in material properties will be managed by the Service Water Integrity Program. For the external piping surfaces exposed to indoor air,

the applicant stated that there is no aging effect and did not propose an AMP. The AMR items cite generic note F. The staff's evaluation of plastic piping exposed externally to indoor air is documented in SER Section 3.3A.2.3.15.

In its evaluation for plastic piping exposed internally to raw water, the staff noted that the applicant's aging management approach is consistent with the guidance in the GALL Report, Revision 2. GALL Report, Revision 2, items VII.C1.AP-238 and VII.C1.AP-239 state that plastic piping exposed to raw water is susceptible to cracking, blistering, and changes in color due to water absorption and recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to manage these aging effects. GALL Report AMP XI.M20 recommends that the inspection scope, methods, and frequency be in accordance with the applicant's response to NRC Generic Letter (GL) 89-13, "Service Water System Problems Affecting Safety-Related Components."

The staff's evaluation of the applicant's Service Water Integrity Program is documented in SER Section 3.0.3.1.14. The staff noted that the applicant's program relies on the implementation of the recommendations of GL 89-13 to assure that the effects of aging on the service water system are adequately managed. The applicant's response to GL 89-13 in a letter dated February 2, 1990, states that visual inspections are used to identify fouling, sedimentation, and corrosion of the internal surfaces of service water system components (Ref. 39). Although the staff recognizes that the applicant's response to GL 89-13 does not specifically address changes in material properties of plastic piping, the staff finds the applicant's proposal acceptable because the visual inspections are capable of detecting changes in color and surface condition that indicate changes in material properties.

3.3A.2.3.10 Fuel Oil System—Summary of Aging Management Review—LRA Table 3.3.2-13-IP2

<u>Copper alloy heat exchanger tube exposed externally to indoor air</u>. By letter dated September 26, 2013, the applicant amended LRA Table 3.3.2-13-IP2 by adding copper alloy with greater than 15 percent zinc heat exchanger tubes which are exposed externally to indoor air and will be managed for fouling. This AMR item, which cites generic note G, credits the Periodic Surveillance and Preventive Maintenance Program. By letter dated December 12, 2013, the applicant removed this line item from the table because it had re-evaluated the CLB and determined that it no longer relied on the black start diesel (GT3-BSD), so it removed from the scope of license renewal all previously included components associated with GT3-BSD.

<u>Aluminum turbochargers exposed internally to exhaust gas</u>. By letter dated September 26, 2013, the applicant amended LRA Table 3.3.2-13-IP2 by adding aluminum turbochargers which are exposed internally to exhaust gas and will be managed for loss of material by the Periodic Surveillance and Preventive Maintenance Program. The AMR item cites generic note G. By letter dated December 12, 2013, the applicant removed this line item because it had re-evaluated the CLB and determined that it no longer relied on the black start diesel (GT3-BSD), so it removed from the scope of license renewal all previously included components associated with GT3-BSD.

<u>Stainless steel flexible bellows and carbon steel silencers exposed internally to exhaust gas</u>. By letter dated September 26, 2013, the applicant amended LRA Table 3.3.2-13-IP2 by adding stainless steel flexible bellows and carbon steel silencers which are exposed to exhaust gas (internal) and will be managed for cracking fatigue. These AMR items, which cite generic

note H, credit the Periodic Surveillance and Preventive Maintenance Program. By letter dated December 12, 2013, the applicant removed these line items because it had re-evaluated the CLB and determined that it no longer relied on the black start diesel (GT3-BSD), so it removed from the scope of license renewal all previously included components associated with GT3-BSD.

3.3A.2.3.35 Water Treatment Plant System, Nonsafety-Related Components Potentially Affecting Safety Function—Summary of Aging Management Review—LRA Table 3.3.2-19-43-IP2

By letter dated September 26, 2012, the applicant amended LRA Table 3.3.3-19-43-IP2 by adding stainless steel bolting which is exposed to outdoor air and will be managed for loss of material by the Bolting Integrity Program. The AMR item cites generic note G. The staff's evaluation of this material, environment, aging effect, and program combination is documented in SER Section 3.3A.2.3.4. The staff noted that the applicant did not include cracking as an AERM. When stainless steel materials are exposed to outdoor air they can be susceptible to cracking depending on plant-specific environmental conditions. SER Section 3.0.3.2.2, "Bolting Integrity Program," addresses cracking by stating that, "[t]he program periodically inspects closure bolting for signs of leakage that may be caused by crack initiation, loss of preload, or loss of material due to corrosion. The program also includes preventive measures to preclude or minimize loss of preload and cracking." The staff finds the applicant's proposal acceptable because the inspector will be inspecting for signs of leakage which would occur regardless of the aging effect (i.e., as a result of loss of material, cracking, or loss of preload).

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

Copper piping exposed to outdoor air. By letter dated October 18, 2012, the applicant amended LRA Table 3.3.2-17-IP3 by adding copper piping which is exposed to outdoor air and will be managed for loss of material by the Buried Piping and Tanks Inspection Program. The AMR item cites generic note G. The applicant stated that this piping is located in underground vaults or pipe trenches.

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 guidance in GALL Report, Revision 2, item AP-159, states that loss of material due to pitting and crevice corrosion is the only applicable aging effect. Accordingly, 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 Buried Piping and Tanks Inspection Program is documented in SER Section 3.0.3.1.2. The staff finds the applicant's proposal to manage aging using the Buried Piping and Tanks Inspection Program acceptable because (a) although the piping is not coated, the applicant has significantly increased the frequency of inspections to every 2 years from every 10 years as recommended in LR-ISG-2011-03; (b) the applicant is inspecting all of the underground piping instead of two percent of the pipe as recommended in LR-ISG-2011-03; (c) the visual inspections before the period of extended operation and those conducted during the period of extended operation are capable of detecting loss of material before the piping would be unable to perform its intended function; and (d) the inspection frequencies would not be revised to every 10 years as recommended by LR-ISG-2011-03 unless the piping is coated.

On the basis of its review, for these items in LRA Table 3.3.2-17-IP3, the staff concludes that the applicant has demonstrated that the effects of aging for the items will be adequately managed so that their intended function(s) will be maintained in ways consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2B.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

Copper alloy flow element and tubing and gray cast iron valve bodies exposed internally to treated water. By letter dated December 27, 2012, the applicant amended LRA Tables 3.3.2-19-13-IP3 and 3.4.2-5-4-IP2 by adding copper alloy flow elements and tubing and gray cast iron valve bodies which are exposed internally to treated water and will be managed for loss of material by the Periodic Surveillance and Preventive Maintenance Program. The AMR item cites generic note G and plant-specific note 305, which states that this treated-water environment includes water that has been treated but is not maintained by the chemistry-control program. The staff's evaluation of this material, environment, aging effect, and program combination is documented in SER Section 3.3A.2.3.14.

Copper alloy with greater than 15 percent zinc strainer housings exposed internally to treated water. By letter dated December 12, 2013, the applicant amended LRA Table 3.3.2-19-13-IP3 by adding copper alloy with greater than 15 percent zinc strainer housings which are exposed internally to treated water and 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 SER Section 3.3A.2.3.14.

3.3.2B.3.42 Fuel Oil Systems—Summary of Aging Management Review—LRA Table 3.3.2-13-IP3

Aluminum turbocharger exposed internally to exhaust gas. By letter dated December 27, 2012, the applicant amended LRA Table 3.3.2-13-IP3 by adding aluminum turbochargers which are exposed internally to exhaust gas and will be managed for loss of material by the Periodic Surveillance and Preventive Maintenance Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff finds the applicant's proposal acceptable based on its review of the GALL Report and ASM Metals Handbook Desk Edition, Second Edition (Ref. 40), which states that aluminum has good corrosion resistance in natural atmospheres, fresh waters, seawater, and many chemicals and their solutions, as well as not being susceptible to stress corrosion cracking. 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 internal and external surfaces. These visual inspections are capable of detecting a loss of material due to pitting and crevice corrosion, and microbiologically influenced corrosion (MIC).

Copper alloy heat exchanger tube exposed internally to indoor air. By letter dated December 27, 2012, the applicant amended LRA Table 3.3.2-13-IP3 by adding copper alloy with greater than 15 percent zinc heat exchanger tubes which are exposed externally to indoor air and will be managed for fouling by the Periodic Surveillance and Preventive Maintenance Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Items EP-10 and SP-6 in Revision 2 of the GALL Report state that there is no AERM or AMP.

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 fouling as a possible aging effect by using the Periodic Surveillance and Preventive Maintenance Program acceptable because, even though fouling is not expected to occur, the program uses periodic visual inspection of external surfaces, which is capable of detecting fouling.

Stainless steel flexible bellows exposed internally to exhaust gas. By letter dated December 27, 2012, the applicant amended LRA Table 3.3.2-13-IP3 by adding stainless steel flexible bellows and carbon steel silencer which are exposed internally to exhaust gas and will be managed for cracking fatigue by the Periodic Surveillance and Preventive Maintenance Program. The AMR item cites generic note H.

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. Item AP-33 in Revision 2 of the GALL Report states that cracking is the only applicable aging effect for stainless steel exposed to exhaust gas; therefore, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's 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 internal and external surfaces. These visual inspections are capable of detecting cracking.

3.4 Aging Management of Steam and Power Conversion Systems

3.4.1 Summary of Technical Information in the Application

There are no changes or updates to this section of the SER.

3.4.2 Staff Evaluation

There are no changes or updates to this section of the SER.

3.4.2.1 AMR Results Consistent with the GALL Report

LRA Tables 3.4.2-1-IP2 through 3.4.2-5-13-IP2 and 3.4.2-1-IP3 through 3.4.2-4-IP3 summarize the results of AMRs for the steam and power conversion system components and indicate AMRs that are claimed to be consistent with the GALL Report.

Since the issuance of SSER 1, Entergy has amended the LRA in annual updates to the LRA, in response to an RAI, or to correct previous RAI responses.

The staff reviewed the information in the amendments to the LRA. The staff verified that the material presented in the amendments to the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs.

The staff reviewed the amendments 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.

By letter dated January 30, 2012, the applicant submitted corrections to the LRA, identifying an omission in a previous response to an RAI. For the IP2 river water service system, the applicant revised LRA Table 3.4.2-5-11-IP2 to add AMR entries for carbon steel bolting and piping exposed externally to soil with an aging effect of “loss of material,” and generic notes C and A, respectively.

By letter dated September 26, 2012, the applicant submitted a correction to its LRA which amended LRA tables associated with the auxiliary feedwater pump room fire event. The changes were identified during an extent-of-condition review that resulted from the discovery of previously provided information that was either incorrect or omitted. The applicant amended several LRA tables to add or remove components made of copper alloy greater than 15 percent zinc (inhibited and uninhibited), copper alloy, glass, titanium, elastomeric material, gray cast iron, carbon steel, and stainless steel exposed to lubricating oil, condensation, treated water, raw water, outdoor air, indoor air, and treated water greater than 140 °F.

By letter dated December 27, 2012, 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 Table 3.4.2-5-4-IP2 to add gray cast iron valve bodies made of gray cast iron exposed to indoor air.

The staff reviewed the applicant’s revisions, noted above, and found that the additional AMR results are consistent with the GALL Report for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified and that the aging effects listed are appropriate for the combination of materials and environments identified.

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

3.4.2.2.6 Cracking Due to Stress Corrosion Cracking

By letter dated September 26, 2012, the applicant amended LRA Table 3.4.2-5-2-IP2 by adding stainless steel expansion joints and sight glasses which are exposed to treated water greater than 140 °F (internal) and will be managed for cracking. These AMR items, which cite item 3.4.1-14, generic note A, and plant-specific notes 314 and 404, credit the Water Chemistry Control—Primary and Secondary and the One-Time Inspection Programs. The staff's evaluation of this material, environment, aging effect, and program combination is documented in Section 3.4.2.2.6 of the SER.

3.4.2.2.7 Loss of Material Due to Pitting and Crevice Corrosion

(1) By letter dated September 26, 2012, the applicant amended LRA Table 3.4.2-5-2-IP2 by adding stainless steel expansion joints and sight glasses which are exposed to treated water greater than 140 °F (internal) and will be managed for loss of material. These AMR items, which cite item 3.4.1-16, generic note A, and plant-specific note 404, credit the Water Chemistry Control—Primary and Secondary and the One-Time Inspection Programs. The staff's evaluation of this material, environment, aging effect, and program combination is documented in Section 3.4.2.2.7, item (1) of the SER.

3.4.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

3.4.2A.3.5 IP2 Auxiliary Feedwater Pump Room Fire Event—Summary of Aging Management Review—LRA Table 3.4.2-5-1-IP2 through 3.4.2-5-13-IP2

<u>LRA Table 3.4.2-5-2-IP2 Condensate System</u>

By letter dated September 26, 2012, the applicant amended LRA Table 3.4.2-5-2-IP2 by adding an elastomeric expansion joint which is exposed internally to treated water and will be managed for cracking and change in material properties by the Periodic Surveillance and Preventive Maintenance Program. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. GALL Report Table IX.E, "Aging Effects," states that elastomeric components are subject to hardening and loss of strength. The staff noted that hardening in elastomers can result in cracking. Therefore, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's 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 (a) periodic visual inspections and physical manipulation of the flexible connections are performed which are capable of detecting cracking and changes in material properties of elastomeric components; (b) the inspection sample size is increased if aging effects are detected, providing reasonable assurance that aging effects can be detected if they are occurring in other components; and (c) inspection findings are evaluated by the corrective action process, assuring that the intended functions of these components will be maintained consistent with the CLB for the period of extended operation.

The applicant amended LRA Table 3.4.2-5-2-IP2 by also adding titanium heat exchanger tubes which are exposed to treated water (internal) and steam (external) and will be managed for loss of material and fouling by the Water Chemistry Control—Primary and Secondary Program. The AMR items cite generic note F. Additionally, by letter dated July 15, 2013, the applicant amended these line items by adding plant-specific note 404, which states that, "[t]he One-Time

Inspection Program will verify effectiveness of the Water Chemistry Control—Primary and Secondary Program."

The staff's evaluation of the Water Chemistry Control—Primary and Secondary Program is documented in SER Section 3.0.3.2.17. The program includes periodic monitoring and control of known detrimental contaminants such as chlorides, fluorides, dissolved oxygen, and sulfate concentrations below the levels known to result in loss of material or cracking. Water chemistry is in accordance with industry guidelines such as EPRI TR-102134, "Pressurized Water Reactor Secondary Water Chemistry Guidelines-Revision 5" for secondary water chemistry (Ref. 41). The staff's evaluation of the One-Time Inspection Program is documented in SER Section 3.0.3.1.9. The staff finds it acceptable to use the One-Time Inspection Program because the program uses nondestructive techniques that are capable of detecting loss of material and fouling such as visual, ultrasonic, and surface examinations of a representative sample of in-scope components to verify whether the Water Chemistry Control—Primary and Secondary Program has been effective at managing loss of material and fouling. The staff noted that the One-Time Inspection Program does not state that eddy current examinations will be conducted for heat exchanger tubing; however, SER Section 3.0.3.2.16 establishes that the applicant has an eddy current inspection program for heat exchangers that conducts visual inspections and eddy current exams.

The applicant amended LRA Table 3.4.2-5-2-IP2 also by deleting (a) carbon steel piping and thermowells exposed internally to treated water and (b) stainless steel thermowells and tubing exposed internally to treated water greater than 140 °F with an aging effect of cracking due to fatigue. The applicant stated that cracking due to fatigue is not an applicable AERM for these specific components in the condensate system because "water temperatures are not expected to reach levels where fatigue is a concern." During a teleconference call on July 30, 2014, Entergy stated that its determination that cracking due to fatigue is not an aging effect of concern is supported by information in Appendix H to EPRI Report No. 1010639, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 4." Appendix H to EPRI Report 1010639 suggests that systems or portions of systems with operating temperatures below 220 °F for carbon steel or 270 °F for austenitic stainless steel may generally be excluded from fatigue concerns because the fluid temperature would not be expected to vary by more than 150 °F for carbon steel or 200 °F for stainless steel (Ref. 42).

The staff reviewed the criteria for performing cyclical loading analyses in the 1955 Edition of American Standards Association (ASA) B31.1, "American Standard Code for Pressure Piping" (Ref. 43), which is the code of record for IP2 non-Class 1 secondary piping systems, in order to determine whether the subject components could be susceptible to cracking due to fatigue. The staff noted that for Westinghouse-designed PWRs, the normal operating temperatures for secondary-side coolant in the condensate system could range from room temperature when the system is in the cold condition to a conservative maximum temperature of 200 °F for condensate system operations in a hot condition. The staff also noted that the expansion stress methodology of ASA B31.1 Section 622 demonstrates that with a temperature range less than 200 °F, it is reasonable to assume that these components would not be subject to thermal fatigue. Therefore, the staff finds that the deletion of these AMR items from LRA Table 3.4.2-5-2-IP2 is acceptable because the operating temperature range for the condensate system is not sufficiently large enough to initiate fatigue-induced cracking of piping, piping components, and piping elements in the system.

LRA Table 3.4.2-5-4-IP2 City Water System

By letter dated September 26, 2012, the applicant amended LRA Table 3.4.2-5-4-IP2 by noting that the stainless steel piping exposed to outdoor air should have cited generic note G. The stainless steel piping exposed to outdoor air is being managed for loss of material by the External Surfaces Monitoring Program. The staff's evaluation of this material, environment, aging effect, and program combination is documented in SER Section 3.4A.2.3.5.

LRA Table 3.4.2-5-5-IP2 Wash Water System

By letter dated September 26, 2012, the applicant amended LRA Table 3.4.2-5-5-1P2 by adding fiberglass piping which is exposed to outdoor air (external) and raw water (internal) and will be managed for change in material properties by the External Surfaces Monitoring and Periodic Surveillance and Preventive Maintenance Programs respectively. The AMR items cite generic note F. The staff noted that the applicant revised the "Parameters Monitored and Inspected Methods for Specific Aging Effects and Mechanisms" table in LRA Section B.1.29 to state that changes in material properties for fiberglass include cracking, blistering, and change in color, and that a visual inspection (VT-3 or equivalent) will be used to detect the aging effect.

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 fiberglass has excellent resistance to water as evidenced by its common use for boat hulls. The staff noted that based on a review of *Fibres, Plastics, and Rubbers: A Handbook of Common Polymers*, by W.J. Roff (Ref. 44) and Plastic Piping Institute TR-9/2002, "Recommended Design Factors and Design Coefficients for Thermoplastic Pressure Pipe" (Ref. 45), fiberglass-reinforced piping and piping components, in the absence of specific environmental stressors such as high radiation or ozone concentrations, will not exhibit aging effects. However, the ultraviolet light in sunlight can result in changes in material properties. These changes in material properties will manifest themselves as cracking, blistering, and changes in color.

The staff's evaluation of the applicant's External Surfaces Monitoring and Periodic Surveillance and Preventive Maintenance Programs is documented in SER (2009) Sections 3.0.3.2.5 and 3.0.3.3.7 respectively. The staff finds the applicant's proposal to manage aging using the External Surfaces Monitoring and Periodic Surveillance and Preventive Maintenance Programs acceptable because the External Surfaces Monitoring Program uses periodic visual inspections which are capable of detecting cracking, blistering, and change in color and the Periodic Surveillance and Preventive Maintenance Program uses periodic visual inspections of a representative sample of the internals of piping exposed to raw water which are capable of detecting cracking, blistering, and change in color.

LRA Table 3.4.2-5-7-IP2 Instrument Air System

By letter dated September 26, 2012, the applicant amended LRA Table 3.4.2-5-7-IP2 to add plastic heat exchanger tube sheets exposed to treated water (internal) and condensation (external). The applicant stated that there is no aging effect and no AMP is needed. The AMR items cite generic note F.

The staff reviewed the associated items in the LRA and could not confirm that no credible aging effects are applicable for this component, material and environment combination. Regulatory Issue Summary (RIS) 2012-02, dated January 24, 2012, "Insights into Recent License Renewal

Application Consistency with the Generic Aging Lessons Learned Report," provided guidance to the industry in regard to further information required in license renewal applications. In regard to plastic materials, the RIS recommends that when plastic is cited as a material, the applicant should provide further information in a plant-specific note because the term "plastic" is not sufficient to evaluate potential aging effects. The RIS states,

> The plant-specific note should state the actual material type or grade (e.g., polyvinyl chloride (PVC), fiberglass-reinforced vinyl ester) and identify environmental considerations that are not obvious from the LRA, FSAR, or license renewal drawings, such as exposure to ultraviolet light, ozone, high temperatures, chemicals, or radiation. The staff requires this information because susceptibility to aging varies widely with the specific material type and environment.

By letter dated June 12, 2013, the staff issued RAI 3.4A.2.3.5-1 requesting that the applicant provide the specific type of plastic material used for the various components listed in LRA Table 3.4.2-5-7-IP2 and state any applicable aging effects for their given environment, including potential radiation effects. In its response dated July 24, 2013, the applicant stated that the plastic heat exchanger tube sheets used in the instrument air compressor after-coolers are made of Micarta (a phenolic resin laminate) and are exposed to an air temperature less than 200 °F and treated water from 70 to 110 °F. The applicant also stated that the plastic tube sheets are not exposed to ultraviolet light, ozone, high temperatures, aggressive chemicals, or radiation. The applicant further stated that it will manage for change in material properties by inspecting both sides of the tube sheets for cracking, blistering, and change in color once every 5 years using the Periodic Surveillance and Preventative Maintenance Program. The applicant stated that there has been no plant-specific operating experience involving degradation of these tube sheets. The applicant revised LRA Table 3.4.2-5-7-IP2, LRA Section A.2.1.28, and LRA Section B.1.29, "Periodic Surveillance and Preventive Maintenance Program," accordingly.

The staff noted that the *Plastics Engineering Handbook* of the Society of the Plastic Industry, Inc. (Ref. 46), states that phenolic materials are generally suitable for use at temperatures up to 300 °F. The staff also noted that the applicant's temperatures are well below 300 °F. In addition, the trade journal *American Machinist* stated in a 1913 issue (Ref. 47) that: (a) Micarta is not brittle and will not warp, expand, or shrink with age or exposure to weather; (b) it is insoluble in all ordinary solvents and is impervious to moisture; and (c) it is unaffected by heat until a temperature sufficient to cause carbonization is reached. The staff further noted that aging effects such as cracking would be readily apparent to the applicant because either instrument air would enter the cooling system or cooling water would enter the instrument air supply. The staff finds the applicant's use of the Periodic Surveillance and Preventive Maintenance Program acceptable because: (a) industry generic information provides a reasonable basis that the material is not susceptible to aggressive aging in the plant-specific environment; (b) plant-specific operating experience has demonstrated that the tube sheets haven't degraded significantly enough to result in leakage; and (c) the visual inspections conducted every 5 years are capable of detecting cracking, blistering, and change in color.

The staff finds the applicant's response to RAI 3.4A.2.3.5-1 acceptable because the applicant will conduct periodic visual inspections of both sides of the tube sheet every 5 years, which will be capable of detecting cracking, blistering, and changes in color. Additionally, based on plant-specific operating experience, this combination of material and environment has not demonstrated any degradation. The staff's concern described in RAI 3.4A.2.3.5-1 is resolved.

By letter dated July 15, 2013, the applicant amended LRA Table 3.4.2-5-7-IP2 by adding copper-alloy piping which is exposed to soil (external) and will be managed for loss of material by the Buried Piping and Tanks Inspection Program. The AMR item cites generic note G.

The staff reviewed the associated item in the LRA and considered whether the aging effect proposed by the applicant constitutes all of the credible aging effects for this component, material, and environment description. Based on its review of GALL Report item AP-174, which states that loss of material due to pitting and crevice corrosion is the only applicable aging effect, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the applicant's Buried Piping and Tanks Inspection Program is documented in SER Section 3.0.3.1.2. The staff finds the applicant's proposal to manage aging using the Buried Piping and Tanks Inspection Program acceptable because the piping is coated, which mitigates the potential for exposure to the soil environment, and the visual inspections conducted by the Buried Piping and Tanks Inspection Program are capable of detecting damage to the pipe's coating and loss of material.

On the basis of its review, the staff concludes (for this item in LRA Table 3.4.2-5-7-IP2) that 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>LRA Table 3.4.2-5-10-IP2 Lube Oil System</u>

By letter dated September 26, 2012, the applicant amended LRA Table 3.4.2-5-10-IP2 by correcting the environment for the titanium heat exchanger tubes exposed to raw water and lube oil. The AMR items cite generic note F. This amendment corrected the environment by noting that the external surfaces of the tubes are exposed to lube oil in lieu of raw water and the internal surfaces are exposed to raw water in lieu of lube oil. Additionally, by letter dated July 15, 2013, the applicant amended these line items by adding plant-specific note 405, which states that, "[t]he One-Time Inspection Program will verify effectiveness of the Oil Analysis Program." The staff's evaluation of this material, environment, aging effect, and program combination is documented in SER Section 3.4A.2.3.5, LRA Table 3.4.2-5-10-IP2, "Lube Oil System." The staff finds that, with the exception of the following discussion on eddy current testing of heat exchanger tubes, changing the external and internal environment of the tubes does not impact the staff's evaluation and conclusion in the cited SER Section. The staff noted that the One-Time Inspection Program does not state that eddy current examinations will be conducted for heat exchanger tubing; however, SER Section 3.0.3.2.16 establishes that the applicant has an eddy current inspection program for heat exchangers that conducts visual inspections and eddy current exams.

<u>LRA Table 3.4.2-5-13-IP2 Station Air System</u>

By letter dated September 26, 2012, the applicant amended LRA Table 3.4.2-5-13-IP2 by adding copper alloy with greater than 15 percent zinc heat exchanger tubes which are exposed to condensation (internal) and will be managed for fouling by the Periodic Surveillance and Preventative Maintenance Program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Copper-zinc alloys with greater than 15 percent zinc are susceptible to selective leaching and SCC as stated in GALL Report, Table IX.C, “Selected Definitions & Use of Terms for Describing and Standardizing.” This occurs when the components are exposed to ammonia or amines, provided that sufficient tensile stresses are present. The staff noted that it is not common for selective leaching to occur on heat exchanger tubes because fluid velocities within the heat exchanger tubing are typically high enough to preclude any significant accumulation of condensation. The staff also noted that LRA 3.6.2.2.2 states, “IPEC is not located near the seacoast where salt spray is considered, nor is IPEC located near a facility that discharges heavy pollutants.” The staff verified, using overhead imagery, that the Indian Point Energy Center is not located near any source of ammonia (e.g., factories or large agricultural sites that could use significant quantities of fertilizer) that could cause SCC in the heat exchanger tubes. Given that selective leaching and SCC are not applicable, the applicant has identified the applicable aging effects for this material and environment.

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 noted that the applicant proposes to use the Periodic Surveillance and Preventive Maintenance Program to manage the aging of copper alloy with greater than 15 percent zinc heat exchanger tubes through the use of periodic visual inspections, which are conducted at least once every 5 years. The staff noted that the program permits increasing the inspection’s sample size if aging effects are detected. The staff also noted that unacceptable inspection findings are evaluated in accordance with the corrective action process to determine the need for accelerated inspection frequency and for monitoring and trending the results. Based on its review of this component, the staff finds the applicant’s proposal to manage aging using the Periodic Surveillance and Preventive Maintenance Program acceptable because (a) periodic visual inspections are performed which are capable of detecting fouling; (b) the inspection sample size is increased if aging effects are detected, providing reasonable assurance that aging effects can be detected if they are occurring in other components; and (c) inspection findings are evaluated by the corrective action process, assuring that the intended functions of these components will be maintained consistent with the CLB for the period of extended operation.

3.5 Aging Management of Containments, Structures, and Component Supports

There are no changes or updates to this section of the safety evaluation report.

3.6 Aging Management of Electrical and Instrumentation and Control Systems

There are no changes or updates to this section of the safety evaluation report.

SECTION 4

TIME-LIMITED AGING ANALYSES

4.1 Identification of Time-Limited Aging Analyses

There are no changes or updates to this section of the safety evaluation report.

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 SER 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

During the review of the Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3) license renewal application (LRA) by the staff of the U.S. Nuclear Regulatory Commission (NRC) ("the staff"), Entergy Nuclear Operations, Inc. ("Entergy" or "the applicant") made commitments related to aging management programs (AMPs) to manage the aging effects for certain structures and components during the period of extended operation (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 1.

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS			
No.	**Commitment**	**Implementation Schedule**	**Source**
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: Completed IP3: December 12, 2015	NL-07-039 NL-13-122
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 [molybdenum disulfide] MoS_2 for bolting. The Bolting Integrity Program manages loss of preload and loss of material for all external bolting.	IP2: Completed IP3: Completed	NL-07-039 NL-07-153 NL-13-122

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

No.	Commitment	Implementation Schedule	Source
3	Implement the Buried Piping and Tanks Inspection Program for IP2 and IP3 as described in LRA Section B.1.6. This new program will be implemented consistent with the corresponding 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: Completed IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153 NL-09-106 NL-09-111 NL-11-101
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.	IP2: Completed IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153 NL-08-057

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

No.	Commitment	Implementation Schedule	Source
	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.		
5	Enhance the External Surfaces Monitoring Program for IP2 and IP3 to include periodic inspections of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(3). Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(2).	IP2: Completed IP3: December 12, 2015	NL-07-039 NL-13-122
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: Completed IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153

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

No.	Commitment	Implementation Schedule	Source
7	Enhance the Fire Protection Program to inspect external surfaces of the IP3 RCP oil collection systems for loss of material each refueling cycle. Enhance the Fire Protection Program to explicitly state that the IP2 and IP3 diesel fire pump engine sub-systems (including the fuel supply line) shall be observed while the pump is running. Acceptance criteria will be revised to verify that the diesel engine does not exhibit signs of degradation while running; such as fuel oil, lube oil, coolant, or exhaust gas leakage. Enhance the Fire Protection Program to specify that the IP2 and IP3 diesel fire pump engine carbon steel exhaust components are inspected for evidence of corrosion and cracking at least once each operating cycle. Enhance the Fire Protection Program for IP3 to visually inspect the cable spreading room, 480 V switchgear room, and [emergency diesel generator] EDG room [carbon dioxide] CO_2 fire suppression system for signs of degradation, such as corrosion and mechanical damage at least once every six months.	IP2: Completed IP3: December 12, 2015	NL-07-039 NL-13-122
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 of IP2 and IP3 fire protection piping on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion. These inspections will be performed before the end of the current operating term and at intervals thereafter during the period of extended operation. Results of the initial evaluations will be used to determine the appropriate inspection interval to ensure aging effects are identified prior to loss of intended function. Enhance the Fire Water Program to inspect the internal surface of foam based fire suppression tanks. Acceptance criteria will be enhanced to verify no significant corrosion.	IP2: Completed IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153 NL-08-014

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

No.	Commitment	Implementation Schedule	Source
9	Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to implement comparisons to wear rates identified in WCAP-12866. Include provisions to compare data to the previous performances and perform evaluations regarding change to test frequency and scope. Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to specify the acceptance criteria as outlined in WCAP-12866 or other plant-specific values based on evaluation of previous test results. Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to direct evaluation and performance of corrective actions based on tubes that exceed or are projected to exceed the acceptance criteria. Also stipulate that flux thimble tubes that cannot be inspected over the tube length and cannot be shown by analysis to be satisfactory for continued service must be removed from service to ensure the integrity of the reactor coolant system pressure boundary.	IP2: Completed IP3: December 12, 2015	NL-07-039 NL-13-122
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 heat exchanger (IP2 only) Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to perform visual inspection on heat exchangers where non-destructive examination, such as eddy current inspection, is not possible due to heat exchanger design limitations. Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to include consideration of material-environment combinations when determining sample population of heat exchangers. 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	IP2: Completed IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153 NL-09-018

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No.	**Commitment**	**Implementation Schedule**	**Source**
	acceptance criteria for heat exchangers visually inspected to include no indication of tube erosion, vibration wear, corrosion, pitting, fouling, or scaling.		
11	Deleted	N/A	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: Completed IP3: Completed	NL-07-039 NL-13-122
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: Completed IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153 NL-08-057 NL-13-077
14	Implement the Non-EQ Bolted Cable Connections Program for IP2 and IP3 as described in LRA Section B.1.22.	IP2: Completed IP3: December 12, 2015	NL-07-039 NL-13-122
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.	IP2: Completed IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153 NL-11-032 NL-11-096 NL-11-101
16	Implement the Non-EQ Instrumentation Circuits Test Review Program for IP2 and IP3 as described in LRA Section B.1.24.	IP2: Completed	NL-07-039 NL-13-122

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No.	Commitment	Implementation Schedule	Source
	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.	IP3: December 12, 2015	NL-07-153
17	Implement the Non-EQ Insulated Cables and Connections Program for IP2 and IP3 as described in LRA Section B.1.25. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E1, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.	IP2: Completed IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153
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: Completed IP3: December 12, 2015	NL-07-039 NL-13-122 NL-11-101
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: Completed IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153
20	Implement the One-Time Inspection – Small Bore Piping Program for IP2 and IP3 as described in LRA Section B.1.28. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M35, One-Time Inspection of ASME Code Class I Small-Bore Piping.	IP2: Completed IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153
21	Enhance the Periodic Surveillance and Preventive Maintenance Program for IP2 and IP3 as necessary to assure that the effects of aging will be managed such that applicable components	IP2: Completed	NL-07-039 NL-13-122

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No.	**Commitment**	**Implementation Schedule**	**Source**
	will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.	IP3: December 12, 2015	
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: Completed IP3: December 12, 2015	NL-07-039 NL-13-122
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: Completed IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153
24	Enhance the Steam Generator Integrity Program for IP2 and IP3 to require that the results of the condition monitoring assessment are compared to the operational assessment performed for the prior operating cycle with differences evaluated.	IP2: Completed IP3: Completed	NL-07-039 NL-13-122
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)	IP2: Completed IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153 NL-08-057 NL-13-077 NL-08-127 NL-11-032 NL-11-101

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No.	Commitment	Implementation Schedule	Source
	• refueling water storage tank foundation (IP3) • security access and office building (IP3) • service water pipe chase (IP2/3) • service water valve pit (IP3) • superheater stack • transformer/switchyard support structures (IP2) • waste holdup tank pits (IP2/3) 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. 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		

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No.	Commitment	Implementation Schedule	Source
	evaluation of groundwater samples to assess aggressiveness of groundwater to concrete on a periodic basis (at least once every five years). IPEC will obtain samples from at least 5 wells that are representative of the ground water surrounding below-grade site structures and perform an engineering evaluation of the results from those samples for sulfates, pH and chlorides. Additionally, to assess potential indications of spent fuel pool leakage, IPEC will sample for tritium in groundwater wells in close proximity to the IP2 spent fuel pool at least once every 3 months. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspection of normally submerged concrete portions of the intake structures at least once every 5 years. Inspect the baffling/grating partition and support platform of the IP3 intake structure at least once every 5 years. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspection of the degraded areas of the water control structure once per 3 years rather than the normal frequency of once per 5 years during the PEO. Enhance the Structures Monitoring Program to include more detailed quantitative acceptance criteria for inspections of concrete structures in accordance with [American Concrete Institute] ACI 349.3R, “Evaluation of Existing Nuclear Safety-Related Concrete Structures” prior to the period of extended operation.		
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: Completed IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153
27	Implement the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.38. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M13, Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	IP2: Completed IP3: Completed	NL-07-039 NL-13-122 NL-07-153
28	Enhance the Water Chemistry Control—Closed Cooling Water Program to maintain water chemistry of the IP2 SBO/Appendix R diesel generator cooling system per [Electric Power Research Institute] EPRI guidelines.	IP2: Completed IP3: Completed	NL-07-039 NL-13-122 NL-08-057

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No.	**Commitment**	**Implementation Schedule**	**Source**
	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.		
29	Enhance the Water Chemistry Control—Primary and Secondary Program for IP2 to test sulfates monthly in the [refueling water storage tank] RWST with a limit of < 150 ppb.	IP2: Completed	NL-07-039 NL-13-122
30	For aging management of the reactor vessel internals, IPEC will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; 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: Completed IP3: Completed	NL-07-039 NL-13-122 NL-11-107
31	Additional [pressure/temperature] 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: Completed IP3: December 12, 2015	NL-07-039 NL-13-122
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 [reference temperature for pressurized thermal shock] RT_{PTS} screening criterion. Alternatively, the site may choose to implement the revised [pressurized thermal shock] PTS rule when approved.	IP3: December 12, 2015	NL-07-039 NL-08-127
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 [cumulative usage factors] CUFs less than 1.0 when accounting for the effects of reactor water environment. This includes applying the appropriate [environmental fatigue correction factor] F_{en} factors to valid CUFs determined in accordance with one of the following: 1. For locations in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3), with existing fatigue analysis valid for the period of extended operation, use the existing CUF. 2. Additional plant-specific locations with a valid CUF may be evaluated. In particular, the pressurizer lower shell will be reviewed to ensure the surge nozzle remains the limiting component. 3. Representative CUF values from other plants, adjusted to or enveloping the IPEC	IP2: Completed IP3: Completed	NL-07-039 NL-13-122 NL-07-153 NL-08-021 NL-10-082

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS			
No.	**Commitment**	**Implementation Schedule**	**Source**
	plant-specific external loads may be used if demonstrated applicable to IPEC. 4. An analysis using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case) may be performed to determine a valid CUF. (2) Consistent with the Fatigue Monitoring Program, Corrective Actions, repair or replace the affected locations before exceeding a CUF of 1.0.		
34	IP2 SBO / Appendix R diesel generator will be installed and operational by April 30, 2008. This committed change to the facility meets the requirements of 10 CFR 50.59(c)(1) and, therefore, a license amendment pursuant to 10 CFR 50.90 is not required.	IP2: Completed	NL-13-122 NL-07-078 NL-08-074 NL-11-101
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: Completed IP3: December 12, 2015	NL-08-127 NL-13-122 NL-11-101 NL-09-018
36	Perform a one-time inspection and evaluation of a sample of potentially affected IP2 refueling cavity concrete prior to the period of extended operation. The sample will be obtained by core boring the refueling cavity wall in an area that is susceptible to exposure to borated water leakage. The inspection will include an assessment of embedded reinforcing steel. 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: Completed	NL-08-127 NL-11-101 NL-13-122 NL-09-056 NL-09-079
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: Completed IP3: Completed	NL-08-127 NL-13-122

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

No.	Commitment	Implementation Schedule	Source
38	For Reactor Vessel Fluence, should future core loading patterns invalidate the basis for the projected values of RT_{PTS} or CV_{USE} [Charpy V-notch upper-shelf energy], updated calculations will be provided to the NRC.	IP2: Completed IP3: December 12, 2015	NL-08-143 NL-13-122
39	Deleted	N/A	NL-09-079
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: Completed IP3: December 12, 2015	NL-09-106 NL-13-122
41	IPEC will inspect steam generators for both units to assess the condition of the divider plate assembly. The examination technique used will be capable of detecting PWSCC in the steam generator divider plate assembly. The IP2 steam generator divider plate inspections will be completed within the first ten years of the period of extended operation (PEO). The IP3 steam generator divider plate inspections will be completed within the first refueling outage following the beginning of the PEO.	IP2: After the beginning of the PEO and prior to September 28, 2023 IP3: Prior to the end of the first refueling outage following the beginning of the PEO.	NL-11-032 NL-11-074 NL-11-090 NL-11-101
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-tubesheet welds using one of the following two options. <u>Option 1 (Analysis)</u> 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. <u>Option 2 (Inspection)</u> 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:	IP2: Prior to March 2024 IP3: Prior to the end of the first refueling outage following the beginning of the PEO. IP2: Between March 2020 and March 2024 IP3: Prior to the end of	NL-11-032 NL-11-074 NL-11-090 NL-11-096

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

No.	Commitment	Implementation Schedule	Source
	a. The condition will be resolved through repair or engineering evaluation to justify continued service, as appropriate, and b. An ongoing monitoring program will be established to perform routine tube-to-tubesheet weld inspections for the remaining life of the steam generators.	the first refueling outage following the beginning of the PEO.	
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: Completed IP3: December 12, 2015	NL-11-032 NL-13-122 NL-11-101
44	IPEC will include written explanation and justification of any user intervention in future evaluations using the WESTEMS “Design CUF” module.	IP2: Completed IP3: December 12, 2015	NL-11-032 NL-11-101 NL-13-122
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: Completed IP3: December 12, 2015	NL-11-032 NL-11-101 NL-13-122
46	Include in the IP2 [Inservice Inspection] 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: Completed	NL-11-032 NL-11-074 NL-13-122
47	Deleted	N/A	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 [License Renewal Interim Staff Guidance] LR-ISG-2011-03. Visual inspections will be supplemented with surface or volumetric nondestructive testing if indications of significant loss of material are observed. Consistent with revised NUREG-1801 Section XI.M41, such adverse indications will	IP2: Completed IP3: Prior to December 12, 2015	NL-12-174 NL-13-122

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

No.	Commitment	Implementation Schedule	Source
	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).		
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 specified in the Fatigue Monitoring Program, corrective actions include further CUF re-analysis, and/or repair or replacement of the affected components prior to the [cumulative usage factor considering environmental effects] CUF_{en} reaching 1.0.	IP2: Completed IP3: Prior to December 12, 2015	NL-13-052 NL-13-122
50	Replace the IP2 split pins during the 2016 refueling outage (2R22).	IP2: Prior to completion of 2R22 IP3: N/A	NL-13-122 NL-14-067

Appendix B

CHRONOLOGY

This appendix contains a chronological listing of the routine correspondence between the staff of the U.S. Nuclear Regulatory Commission ("NRC" or "the staff") and Entergy Nuclear Operations, Inc. ("Entergy" or "the applicant"), as well as other correspondence regarding the staff's review of the license renewal application (LRA) for Indian Point Nuclear Generating Unit Nos. 2 and 3, Docket Numbers 50-247 and 50-286, issued since the publication of NUREG-1930, Supplement 1, in August 2011.

Document Date	Title
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. (ADAMS Accession No. ML071210512)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application, Cover. (ADAMS Accession No. ML071210516)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application, Page i, Preface, through Chapter 4.0, Page 4.7-4. (ADAMS Accession No. ML071210517)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application, Appendix A, "Updated Final Safety Analysis Report Supplement." (ADAMS Accession No. ML071210520)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix B, "Aging Management Programs and Activities." (ADAMS Accession No. ML071210523)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application, Appendix C [not used in this application]. (ADAMS Accession No. ML071210524)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix D, "Technical Specification Changes." (ADAMS Accession No. ML071210527)
05/03/2007	Indian Point Nuclear Generating Units 2 and 3—Supplement to License Renewal Application. (ADAMS Accession No. ML071280700)
06/21/2007	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Unit 2, Station Blackout (SBO) / Appendix R Diesel Generator Commitment, Response to NRC Review Status of License Renewal Application. (ADAMS Accession No. ML071800318)
08/11/2009	Letter from Entergy to U.S. NRC Regarding Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3. (ADAMS Accession No. ML092150012)
08/11/2009	Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3, Docket Nos. 50-247 and 50-286. (ADAMS Accession No. ML092240268)
11/30/2009	NUREG-1930, "Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3, Docket Nos. 50-247 and 50-286," Volume 1. (ADAMS Accession No. ML093170451)
11/30/2009	NUREG-1930, "Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3, Docket Nos. 50-247 and 50-286," Volume 2. (ADAMS Accession No. ML093170671)

Document Date	Title
07/14/2010	Letter from Entergy to U.S. NRC, "Amendment 9 to License Renewal Application (LRA) – Reactor Vessel Internals Program, Indian Point Nuclear Generating Unit Nos. 2 & 3." (ADAMS Accession No. ML102010102)
08/22/2011	Letter from Entergy to U.S. NRC, "Clarification for Request for Additional Information (RAI) Aging Management Programs." (ADAMS Accession No. ML11243A085)
08/31/2011	Letter from U.S. NRC to Entergy Regarding Supplement to Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3. (ADAMS Accession No. ML11201A033)
08/31/2011	NUREG-1930, Supplement 1, "Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3, Docket Nos. 50-247 and 50-286." (ADAMS Accession No. ML11242A215)
09/28/2011	Letter from Entergy to U.S. NRC Regarding Indian Point, Units 2 & 3 - License Renewal Application - Completion of Commitment 30 re Reactor Vessel Internals Inspection Plan. (ADAMS Accession No. ML11280A121)
12/20/2011	Letter from Entergy to U.S. NRC Regarding Indian Point, Units 2 & 3 - Amendment 11 to License Renewal Application. (LRA). (ADAMS Accession No. ML11363A175)
01/30/2012	Letter from Entergy to U.S. NRC Regarding Indian Point Nuclear Generating Unit Nos. 1, 2 & 3 - Correction to Previous Response Regarding Unit 1 Buried Piping. (ADAMS Accession No. ML12039A178)
02/17/2012	Letter from Entergy to U.S. NRC Regarding Indian Point, Units 2 and 3, License Renewal Application - Revised Reactor Vessel Internals Program and Inspection Plan Compliant with MRP-227-A. (ADAMS Accession No. ML12060A312)
04/19/2012	Letter from U.S. NRC to Entergy Transmitting Inspection Report IR 05000247-12-008, on 03/05/2012 - 03/08/2012, Indian Point Nuclear Generating Unit 2, Review of License Renewal Activities. (ADAMS Accession No. ML12110A315)
05/15/2012	Letter from U.S. NRC to Entergy Regarding Request for Additional Information for the Review of the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application RAI Set 19 - RVIs MRP-227 05-2012. (ADAMS Accession No. ML12125A342)
06/14/2012	Letter from Entergy to U.S. NRC Regarding Indian Point, Units 2 and 3 - Reply to Request for Additional Information Regarding the License Renewal Application. (ADAMS Accession No. ML12184A037)
07/30/2012	Letter from U.S. NRC to Entergy Regarding Project Manager Change for the License Renewal of Indian Point, Units 2 & 3 (TAC ME5407 and MD5408). (ADAMS Accession No. ML12199A025)
09/12/2012	08/08/2012 Summary of Telephone Conference Call Held between U.S. NRC and Entergy Nuclear Operations, Inc., Concerning RAI Set 2012-02, Reactor Vessel Internals Program Pertaining to the Indian Point, Units 2 & 3, License Renewal Application. (ADAMS Accession No. ML12223A367)
09/26/2012	Letter from Entergy to U.S. NRC Regarding Indian Point Nuclear Generating Units 1, 2 & 3 - Correction to Previous Responses Regarding Unit 1 Buried Piping and Unit 2 Auxiliary Feedwater Pump Room Fire Event. (ADAMS Accession No. ML12285A084)

Document Date	Title
09/28/2012	Letter from Entergy to U.S. NRC Regarding Indian Point Nuclear Generating Units 2 & 3 - Reply to Request for Additional Information Regarding the License Renewal Application. (ADAMS Accession No. ML12285A232)
10/16/2012	Letter from U.S. NRC to Entergy Regarding Request for Additional Information for the Review of the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application, Set 2012-03 (TAC Nos. MD5407 and MD5408). (ADAMS Accession No. ML12278A077)
10/17/2012	Letter from Entergy to U.S. NRC Regarding Indian Point, Units 2 & 3 - Reply to Request for Additional Information Regarding the License Renewal Application. (ADAMS Accession No. ML12300A391)
10/18/2012	Letter from Entergy to U.S. NRC Regarding Indian Point, Units 2 & 3, Clarification of Underground Piping Information Provided in Letter NL-11-032 Regarding the License Renewal Application. (ADAMS Accession No. ML12310A061)
10/31/2012	10/11/2012 Summary of Telephone Conference Call Held Between the U.S. NRC and Entergy Nuclear Operations, Inc., Concerning the Indian Point Nuclear Generating Unit Nos. 2 and 3 License Renewal Application. (ADAMS Accession No. ML12289A880)
11/20/2012	Letter from Entergy to U.S. NRC Regarding Indian Point, Units 2 and 3 - Reply to Request for Additional Information Regarding the License Renewal Application. (ADAMS Accession No. ML12340A154)
11/29/2012	Letter from Entergy to U.S. NRC Regarding Indian Point Nuclear Generating Unit Nos. 2 & 3 - Additional Clarification of Underground Piping Information Provided in Letter NL-12-149 Regarding the License Renewal Application. (ADAMS Accession No. ML12354A314)
12/27/2012	Letter from Entergy to U.S. NRC Regarding Indian Point Nuclear Generating, Units 2 and 3 - Amendment 12 to License Renewal Application. (ADAMS Accession No. ML13003A178)
03/05/2013	Letter from Entergy to U.S. NRC Regarding Indian Point, Units 2 & 3 - Revision to the Response to Request for Additional Information (RAI) about Aging Management Programs. (ADAMS Accession No. ML13074A020)
03/18/2013	Letter from Entergy to U.S. NRC Regarding Indian Point, Units 2 and 3 - Amendment 13 to License Renewal Application Pertaining to One-Time Inspection and Selective Leaching Programs. (ADAMS Accession No. ML13094A369)
05/01/2013	Letter from Entergy to U.S. NRC Regarding Actions Required Before Entry into Period of Extended Operation Associated with License Renewal Application for Indian Point Energy Center Unit 2. (ADAMS Accession No. ML13142A203)
05/06/2013	Letter from Entergy to U.S. NRC Regarding Indian Point, Units 2 & 3 - License Renewal Application - Update to Electrical MEB and Structures Monitoring Program Scope, Aging Management Programs. (ADAMS Accession No. ML13142A013)
05/07/2013	Letter from Entergy to U.S. NRC Regarding Indian Point Nuclear Generating, Units 2 & 3 - Reply to Request for Additional Information Regarding the License Renewal Application. (ADAMS Accession No. ML13142A202)
05/14/2013	Letter from Entergy to U.S. NRC Regarding Indian Point Nuclear Generating, Unit 2, Update to Previous Plans Regarding Refueling Cavity Repairs. (ADAMS Accession No. ML13141A402)

Document Date	Title
06/12/2013	Letter from U.S. NRC to Entergy Regarding Request for Additional Information for the review of the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application, Set 2013-02 (TAC Nos. MD5407 and MD5408). (ADAMS Accession No. ML13162A606)
07/02/2013	Summary of Conference Call Held on June 4, 2013, Between the U.S. Nuclear Regulatory Commission and Entergy Nuclear Operations, Inc., Concerning Responses to RAIs Regarding the Reactor Vessel Internals Program at Indian Point Nuclear Generating Unit Nos. 2 and 3. (ADAMS Accession No. ML13171A368)
07/05/2013	Letter from U.S. NRC to Entergy Transmitting Inspection Report IR 05000247-13-009; 05/6/2013 to 05/23/2013; Indian Point Nuclear Generating Unit 2; License Renewal Team Inspection. (ADAMS Accession No. ML13186A179)
07/15/2013	Letter from Entergy to U.S. NRC Regarding Correction to a Previous Response Regarding the Unit 2 Auxiliary Feedwater Pump Room Fire Event. (ADAMS Accession No. ML13200A021)
07/17/2013	Letter from U.S. NRC to Entergy Regarding Request for Additional Information for the Review of the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application, Set 2013-03 (TAC Nos. MD5407 and MD5408). (ADAMS Accession No. ML13186A169)
07/19/2013	Letter from U.S. NRC to Entergy Regarding Project Manager Change for the License Renewal of Indian Point, Units 2 and 3 (TAC Nos. MD5407 and MD5408). (ADAMS Accession No. ML13134A367)
07/24/2013	Letter from Entergy to U.S. NRC Regarding Indian Point, Units 2 and 3, Response to Request for Additional Information for the Review of the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. (ADAMS Accession No. ML13211A173)
07/26/2013	Letter from U.S. NRC to Entergy Regarding Request for Additional Information for the Review of the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application, Set 2013-04 (TAC Nos. MD5407 and MD5408). (ADAMS Accession No. ML13204A199)
08/15/2013	07/19/2013 Summary of Conference Call Held between the U.S. NRC and Entergy Nuclear Operations, Inc., Concerning Draft Request for Additional Information Related to Amendment 9 to License Renewal Application. (ADAMS Accession No. ML13211A264)
08/16/2013	Letter from Entergy to U.S. NRC Regarding Indian Point, Units 2 & 3 - Letter In Reply to Request for Additional Information Regarding the License Renewal Application. (ADAMS Accession No. ML13247A171)
08/19/2013	Letter from U.S. NRC to Entergy Regarding Indian Point Nuclear Generating Unit No. 2 - Actions To Be Completed Before Entering the Period of Timely Renewal. (ADAMS Accession No. ML13197A034)
08/28/2013	Letter from Entergy to U.S. NRC Regarding Indian Point Nuclear Generating Unit 2 Implementation of License Renewal Regulatory Commitments. (ADAMS Accession No. ML13247A175)
08/29/2013	08/13/2013 Summary of Conference Call Held on August 13, 2013, between the U.S. NRC and Entergy Nuclear Operations, Inc., Concerning Request for Additional Information Responses on Cathodic Protection – Indian Point Nuclear Generating Unit Nos. 2 and 3. (ADAMS Accession No. ML13231A040)

Document Date	Title
09/03/2013	Letter from U.S. NRC to Entergy Regarding Request for Additional Information for the Review of the Indian Point Nuclear Generating, Units 2 and 3, License Renewal Application, Set 2013-05 (TAC Nos. MD5407 and MD5408). (ADAMS Accession No. ML13240A076)
09/13/2013	Indian Point Nuclear Generating Unit 2 - NRC License Renewal Team Inspection Report 05000247/2013010 (ADAMS Accession No. ML13263A020)
09/19/2013	Letter from U.S. NRC to Entergy Regarding Indian Point Nuclear Generating Unit 2 - NRC License Renewal Team Inspection Report 05000247/2013010. (ADAMS Accession No. ML13263A020)
09/23/2013	Summary of Conference Call Held on July 2, 2013, Between the U.S. NRC and Entergy Nuclear Operations, Inc., Concerning May 6, 2013 Letter Regarding Changes to Metal Enclosed Bus Inspection Program for Indian Point Nuclear Generating Unit Nos. 2 and 3. (ADAMS Accession No. ML13184A082)
09/26/2013	Letter from Entergy to U.S. NRC Regarding Indian Point Nuclear Generating, Unit No. 2 - Amendment 14 to License Renewal Application. (ADAMS Accession No. ML13274A238)
09/27/2013	Letter from Entergy to U.S. NRC Regarding Indian Point Nuclear Generating Unit Nos. 2 & 3 - Reply to Request for Additional Information Regarding the License Renewal Application. (ADAMS Accession No. ML13277A007)
10/03/2013	Letter from Entergy to U.S. NRC Regarding Indian Point Nuclear Generating, Units 2 & 3 - Reply to Request for Additional Information Regarding the License Renewal Application. (ADAMS Accession No. ML13282A140)
11/19/2013	Letter from U.S. NRC to Entergy Regarding Request for Additional Information for the Review of the Indian Point Nuclear Generating, Units 2 and 3, License Renewal Application, Set 2013-06 (TAC Nos. MD5407 and MD5408). (ADAMS Accession No. ML13318A450)
12/12/2013	Letter from Entergy to U.S. NRC Regarding Indian Point, Unit 2 and 3, Amendment 15 to License Renewal Application. (ADAMS Accession No. ML13354B873)
01/02/2014	Letter from Entergy to U.S. NRC Regarding Indian Point Nuclear Generating, Units 2 and 3, Reply to Request for Additional Information Regarding the License Renewal Application. (ADAMS Accession No. ML14014A276)
01/09/2014	Summary of Conference Call Held on December 18, 2013, Between the U.S. NRC and Entergy Nuclear Operations, Inc., Concerning Applicant or Licensee Action Item 7 from MRP-227-A. (ADAMS Accession No. ML13354C017)
01/16/2014	Letter from Entergy to U.S. NRC Regarding Indian Point, Units 2 & 3 - Reply to Request for Additional Information Regarding the License Renewal Application. (ADAMS Accession No. ML14027A413)
01/16/2014	Letter from Entergy to U.S. NRC Regarding Indian Point, Units 1 and 2, Enclosure 2 to NL-14-010, Attachment 2, Final Response to U.S. NRC RAI 6-A Items 1 and 2 on the RVI Program and RVI Inspection Plan. (ADAMS Accession No. ML14027A415) [Note: this letter is replaced by the September 8, 2014 letter]
01/28/2014	Letter from Entergy to U.S. NRC Regarding Indian Point, Units 2 & 3 - Additional Information Regarding the License Renewal Application - Action Item 7 from MRP-227-A. (ADAMS Accession No. ML14038A150)

Document Date	Title
03/21/2014	02/20/2014 Summary of Conference Call Held on February 20, 2014, Between the U.S. NRC and Entergy Nuclear Operations, Inc., Concerning a Draft Request for Additional Information on LR-ISG-2012-02 and Draft LR-ISG-2013-01. (ADAMS Accession No. ML14078A399)
04/01/2014	Letter from U.S. NRC to Entergy Regarding Request for Additional Information for the Review of the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application, Set 2014-01 (TAC Nos. MD5407 and MD5408). (ADAMS Accession No. ML14084A387)
04/09/2014	Letter from U.S. NRC to Entergy Regarding Request for Additional Information for the Review of the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application, Set 2014-02. (ADAMS Accession No. ML14094A173)
04/24/2014	03/26/2014 Summary of Conference Call Held on March 26, 2014, Between the U.S. NRC and Entergy Nuclear Operations, Inc., Concerning a Draft Request for Additional Information on the Reactor Vessel Internals Program (ADAMS Accession No. ML14105A354)
06/09/2014	Letter from Entergy to U.S. NRC Regarding Reply to Request for Additional Information Regarding the License Renewal Application, Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application, Set 2014-02 (TAC Nos. MD5407 and MD5408), dated April 9, 2014. (ADAMS Accession No. ML14176A159)
08/01/2014	Summary of Conference Calls Held on June 19 and July 16, 2014, Between the U.S. NRC and Entergy Nuclear Operations, Inc., Regarding Entergy's Response to a Request for Additional Information on Applicant or Licensee Action Item 7 from MRP-227-A. (ADAMS Accession No. ML14206B128)
08/05/2014	Letter from Entergy to U.S. NRC Regarding Reply to Request for Additional Information Regarding the License Renewal Application, Indian Point Nuclear Generating Unit Nos. 2 and 3, Docket Nos. 50-247 and 50-286, License Nos. DPR-26 and DPR-64. (ADAMS Accession No. ML14225A777)
08/14/2014	Letter from U.S. NRC to Mr. James A. Gresham, Westinghouse Electric Company, Subject: Review of Draft Audit Report Regarding Indian Point Nuclear Generating Unit Nos. 2 and 3 License Renewal Application (TAC Nos. MD5407 and MD5408). (ADAMS Accession No. ML14206B174)
08/14/2014	Letter from U.S. NRC to Entergy Regarding Indian Point Nuclear Generating Unit Nos. 2 and 3 - Request for Withholding Information from Public Disclosure (TAC Nos. MD5407 and MD5408). (ADAMS Accession No. ML14217A206)
09/08/2014	Letter from Entergy to U.S. NRC Regarding Reply to Request for Additional Information Regarding the License Renewal Application, Indian Point Nuclear Generating Unit Nos. 2 and 3, Docket Nos. 50-247 and 50-286, License Nos. DPR-26 and DPR-64. (ADAMS Accession No. ML14267A270) [Note: this letter replaces the January 16, 2014 letter]
09/09/2014	Letter from Mr. James A. Gresham, Westinghouse Electric Company, to U.S. NRC, Subject: Submittal of "Westinghouse Review of Draft NRC Audit Report Regarding Indian Point Nuclear Generating Unit Nos. 2 and 3." (ADAMS Accession No. ML14259A115)
09/10/2014	Summary of Conference Call Held on July 30, 2014, Between the U.S. NRC and Entergy Nuclear Operations, Inc., Regarding a Draft Request for Additional Information on Removal of Certain Aging Management Review Items. (ADAMS Accession No. ML14238A726)

Document Date	Title
09/25/2014	Letter from U.S. NRC to Mr. James A. Gresham, Westinghouse Electric Company, Subject: Request for Withholding Information from Public Disclosure Regarding the Aging Management Audit Report Associated with Indian Point Nuclear Generating Unit Nos. 2 and 3 License Renewal Application. (ADAMS Accession No. ML14265A226)
10/06/2014	U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Division of License Renewal Aging Management Audit Report (Non-Proprietary). (ADAMS Accession No. ML14266A273)
10/15/2014	Letter from U.S. NRC to Entergy Regarding Indian Point Nuclear Generating Unit Nos. 2 and 3 - Request for Withholding Information from Public Disclosure (TAC Nos. MD5407 and MD5408). (ADAMS Accession No. ML14268A476)

Appendix 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.

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Appendix D

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This appendix lists the references used throughout this supplement to the safety evaluation report for review of the license renewal application for Indian Point Nuclear Generating Unit Nos. 2 and 3.

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