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Sent: Wednesday, January 28, 2009 1:04 PM
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Subject: IPEC License Renewal RAI Reply - Miscellaneous Items
Attachments: NL-09-018.pdf

Bo and Kim,

Attached is an advance electronic copy of IPEC's License Renewal RAI Reply – Miscellaneous Items. Hard copy will follow in the mail.

Thanks,
Donna

Hearing Identifier: IndianPointUnits2and3NonPublic_EX
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Fred Dacimo
Vice President
License Renewal

January 27, 2009

Re: Indian Point Units 2 & 3
Docket Nos. 50-247 & 50-286
NL-09-018

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

SUBJECT: Entergy Nuclear Operations Inc.
Indian Point Nuclear Generating Unit Nos. 2 & 3
Docket Nos. 50-247 and 50-286
Reply to Request for Additional Information – Miscellaneous Items

REFERENCES: 1. NRC Letter dated December 30, 2008, "Request for Additional Information for the Review of the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application – Miscellaneous Items

Dear Sir or Madam:

Entergy Nuclear Operations, Inc is providing, in Attachment I, the additional information requested in the referenced letter pertaining to NRC review of the License Renewal Application for Indian Point 2 and Indian Point 3. The additional information provided in this transmittal provides clarifications and additional information to previously submitted information in response to staff questions.

Attachment 2 consists of a revision to the list of regulatory commitments providing clarification on the Heat Exchanger Monitoring Program (Commitment #10) and the Containment Liner Inspection (Commitment #35).

If you have any questions, or require additional information, please contact Mr. Robert Walpole at 914-734-6710.

I declare under penalty of perjury that the foregoing is true and correct. Executed on 1/27/09.

Sincerely,

Fred R. Dacimo
Vice President
License Renewal

Attachments:

1. IPEC LRA Responses for RAIs and SER Open Items
2. IPEC Commitment List, Revision 7

cc: Mr. Samuel J. Collins, Regional Administrator, NRC Region I
Mr. Sherwin E. Turk, NRC Office of General Counsel, Special Counsel
Mr. Kenneth Chang, NRC Branch Chief, Engineering Review Branch I
Mr. Bo M. Pham, NRC Environmental Project Manager
Mr. John Boska, NRR Senior Project Manager
Mr. Paul Eddy, New York State Department of Public Service
NRC Resident Inspector's Office
Mr. Robert Callender, Vice President NYSERDA

ATTACHMENT 1 TO NL-09-018

IPEC LRA Responses for RAIs and SER Open Items

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 & 3
DOCKET NOS. 50-247 AND 50-286

INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3
LICENSE RENEWAL APPLICATION
REQUEST FOR ADDITIONAL INFORMATION (RAI)

RAI-2.3A.4.2-2 (Unit 2)

Indian Point Nuclear Generating Unit No. 2 (IP2) UFSAR Section 14.1.10, "Excessive Heat Removal Due To Feedwater System Malfunctions," explains in the case of excessive feedwater (FW) flow resulting from an accidental full opening of one FW control valve, the resulting transient is similar to, but less severe than the hypothetical steamline break transient described in Section 14.2.5. Therefore, the failure is bounded by the analysis presented in Section 14.2.5. UFSAR Section 14.2.5.6, Containment Peak Pressure for a Postulated Steam Line Break, specifically indicates that for IP2 the applicant takes credit for the main FW stop valves, BFD-5's, closing within 120 seconds, in the event of the failure of the main FW control valve. In response to a telephone conference call the staff had with the applicant on March 7, 2008 (ADAMS Accession number ML080840568), the applicant revised its response to RAI 2.3A.4.2-1. In its amended response, dated March 24, 2008, the applicant reiterated that the FW valves credited for FW isolation are safety-related. This response did not specifically include FW isolation valves, BFD-5's, by name, and they are not included within the boundary flags for system scope, nor highlighted on license renewal drawings for having an intended function in accordance with 10 CFR 54.4(a)(1).

The staff requests the applicant to: a) justify the exclusion of these isolation valves, BFD-5's, from the scope of license renewal in accordance with 10 CFR 54.4(a)(1), and b) verify whether a similar issue to Unit 3 exists for Unit 2 as stated in the following RAI (RAI 2.3B.4.2-2) for Unit 3, which credits closure of BFD-5's and BFD-90's valves in the event of a main steam line break on a high steam flow safety injection logic, which would require not only the inclusion of BFD-5's but also BFD-90's within scope per 10 CFR 54.4(a)(1).

Response for RAI-2.3A.4.2-2 (Unit 2)

a) The Entergy response dated March 24, 2008 indicated that feedwater valves within boundary flags on drawing LRA-9321-2019-0 are safety-related. However, the BFD-5's (BFD-5, BFD-5-1, BFD-5-2, and BFD-5-3) are nonsafety-related valves as indicated by their location inside the non-quality group boundary symbols on drawing LRA-9321-2019-0 and as indicated in the site component database. As described in UFSAR Section 14.2.5.6, these valves provide backup feedwater isolation capability.

   NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum from Director, NRR to NRR Staff," Issue 1, includes an analysis of the treatment of non-safety grade equipment in evaluations of postulated steam line break accidents. Page 1-11 states the following.

> Thus, the staff believes that it is acceptable to rely on these non-safety grade components in the steam and feedwater systems because their design and performance are compatible with the accident conditions for which they are called upon to function. It is the staff position that utilization of these components as a backup to a single failure in safety grade components adequately protects the health and safety of the public.

The BFD-5's are within the scope of license renewal and subject to aging management review and evaluated in Table 3.3.2-19-12-IP2.

b) The IP2 UFSAR clearly states in Section 14.2.5.6 that no credit is taken for the feedwater bypass stop valves (BFD-90's) in the postulated steam line break analysis. However, the BFD-90s are within the scope of license renewal and subject to aging management review and are evaluated in Table 3.3.2-19-12-IP2.

RAI 2.3B.4.2-2 (Unit 3)

Similar to the issue stated in the above RAI for Unit 2 (RAI-2.3A.4.2-2), a comparable issue applies for FW isolation valves for Unit 3. However, the Unit 3 analysis differs slightly from Unit 2 to include the FW isolation valves (BFD-90's) associated with the FW regulating bypass valves. UFSAR Section 14.2.5, "Rupture of a Steam Pipe," states that in the event of a main steam line break incident, the motor-operated valves (MOVs) associated with each of the FW regulating valves (FRVs) will also close. The mechanical stroke time of 120 seconds to close these associated MOVs has been analyzed and is acceptable. In addition, license renewal drawing 9321-20193 shows a "HIGH STEAM FLOW SI LOGIC" signal goes to these motor operated isolation valves. UFSAR Section 14.2.5.1 states that redundant isolation of the main FW lines is necessary, because sustained high FW flow would cause additional cooldown.

Therefore, in addition to the normal control action which will close the main FW valves, any boundary flags for system scope, nor highlighted on LRA drawings for having an intended function in accordance with 10 CFR 54.4(a)(1). In its amended response, dated March 24, 2008, the applicant did not specifically include these FW isolation valves, BFD-5's and BFD-90's, by name.

The staff requests the applicant to justify the exclusion of these isolation valves, BFD-5's and BFD-90's, from scope of license renewal in accordance with 10 CFR 54.4(a)(1) safety injection signal will rapidly close all FW control valves (including the motor-operated block valves and low-flow bypass valves), trip the main FW pumps, and close the FW pump discharge valves. The motor-operated block valves shown on the license renewal drawings are BFD-5's and BFD-90's for the main FRVs, and the low flow bypass regulating valves, respectively. The FW isolation valves, BFD-5's and BFD-90's, are not shown to be included within the system.

Response for RAI-2.3B.4.2-2 (Unit 3)

The BFD-5's (BFD-5-1, BFD-5-2, BFD-5-3, and BFD-5-4) and BFD-90's (BFD-90-1, BFD-90-2, BFD-90-3, and BFD-90-4) are nonsafety-related valves as indicated by their location inside the Class I boundary on drawing LRA-9321-20193 and as indicated in the site component database. As described in UFSAR Section 14.2.5.1, Item 3, the motor operated block valves (BFD-5's) and low flow bypass valves (BFD-90's) provide backup isolation capability.

The staff previously evaluated BFD-5's (MFIIV) and BFD-90's (MFBIIV) in a letter from George F Wunder (NRC) to Michael Kansler (Entergy), "Indian Point Nuclear Generating Unit No. 3 – Issuance of Amendment RE: Main Feedwater Isolation Valve Modifications (TAC NO. MB0179), dated April 18, 2001 (ML010640142). Excerpts from Section 3.0, Evaluation, are shown below.

> "Though the MFIIVs, MFBIIVs, and valve operators will remain non-safety grade, the automatic closure of these isolation valves on a SI signal will be credited in the analysis for mitigation of an MSLB inside containment. The staff generally requires that only safety grade structure, systems, or components (SSC) can be credited in the design basis safety analysis. However, as specified in the Standard Review Plan (SRP), taking credit for non-safety related equipment in the safety analyses of MSLB accidents is acceptable.
>
> This position is also discussed in NUREG-0138 in addressing Issue No. 1, "Treatment of Non-Safety Grade Equipment in Evaluation of Postulated Steam Line Break Accidents," which states the following.
>
>> ... the staff believes that it is acceptable to rely on these non-safety grade components in the steam and feedwater systems because their design and performance are compatible with the accident conditions for which they are called upon to function. It is the staff position that utilization of these components as a backup to a single failure in safety grade components adequately protects the health and safety of the public."

The BFD-5s and BFD-90s are in the scope of license renewal and subject to aging management review. These components are evaluated in Table 3.3.2-19-34-IP3.

RAI-2.3A.4.5-2 (Unit 2)

In LRA Section 2.3.4.5 the applicant describes systems not described elsewhere in the application credited for mitigating the consequences of a Unit 2 fire event in the auxiliary feedwater (AFW) room. Each system listed has the following intended function: to support safe shutdown in the event of a fire in the auxiliary feed pump room (10 CFR 50.48) function in accordance 10 CFR 54.4(a)(3). The applicant states "no LRA drawings are provided based on the intended function of supporting safe shutdown in the event of a fire in the auxiliary feed pump room." However, the applicant states in LRA Section 2.2 that "[c]omponents subject to aging management review are highlighted on license renewal drawings, with the exception of components in scope for 10 CFR 54.4(a)(2)." Since the structures and components that support mitigating the consequences of a fire event are in scope in accordance with 10 CFR 54.4(a)(3) and subject to an AMR in accordance with 10 CFR 54.21(a)(1), then the components should have been highlighted on license renewal drawings. However, the applicant did not highlight the components or flowpaths needed to support this event. In addition, the applicant did not, in accordance with 10 CFR 54.21(a)(1), identify and list the structures and components that are subject to an AMR. Therefore, based upon the information provided in the LRA, the staff was not able to verify which components are included in scope to perform the stated function and are subject to an AMR.

For each system identified in LRA Section 2.3.4.5, the staff requests the applicant to a) identify the system support function for the AFW pump room fire event, b) clearly identify the portions of the systems' flow paths that support these functions that are subject to an AMR, and c) identify the portions of these flow paths that are not already in scope for 10 CFR 54.4(a)(1) or (a)(2).

Response for RAI-2.3A.4.5-2 (Unit 2)

Background
As discussed in section 2.3.4.5 of the LRA, a combination of secondary systems and components are credited for one hour for supplying make up water through the main feedwater isolation valves to the steam generators during the AFW (Auxiliary Feedwater) pump room fire event (Fire Zone 23/Fire Area C). This is necessary because under the current licensing basis, plant personnel are assumed unable to re-enter the AFW pump room for one hour following onset of the fire.

A conservative assessment of systems that support this event was performed for license renewal. For example, the wash water system was included in scope even though the travelling screens may not require cleaning during the one hour duration of the event, and several sources of instrument air were also included though only one would be needed.

Feedwater may be supplied by the main feedwater pumps in combination with the condensate pumps or by the condensate pumps alone after steam pressure is decreased. License renewal scoping conservatively identified systems that are required for main feedwater pump operation or condensate pump operation since this provides the maximum operator flexibility in response to the event. As a result, many auxiliary systems were included such as the main condenser to support the main feedwater pump turbine exhaust, circulating water to support condenser cooling, and main feedwater pump supporting sub-systems such as lube oil and cooling water.

System Review

For each system described in LRA Section 2.3.4.5, the following subsections identify:

a. the system support function for the AFW pump room fire event,

b. the portions of the system flow path that support these functions and hence are subject to aging management review (STAMR), and

c. the portions of the flow path that are not already in scope and STAMR for 10 CFR 54.4(a)(1) or (a)(2).

The response to RAI-3.4.2-1 includes a specific listing of the component types that were not already in scope and STAMR for 10 CFR 54.4(a)(1) or (a)(2).

Auxiliary Steam System (AS)

a. The auxiliary steam system provides gland seal steam supply.
b. The portions of the system credited are the main steam supply to the auxiliary steam system and the components in the flow path of the auxiliary steam supply to the gland seals of the main turbine. The main steam supply to the auxiliary steam system is shown on LRA drawing LRA-227780.
c. All portions of the AS flow path are in scope and STAMR for 10 CFR 54.4(a)(2). The specific component types are included in LRA Table 3.3.2-19-1-IP2, Auxiliary Steam System.

Conventional Closed Cooling System (CCC)

a. The conventional closed cooling system provides cooling to the condensate pump motor bearings.
b. The conventional closed cooling pumps, heat exchangers and the components in the flow path to and from the condensate pumps are credited during the AFW pump room fire event.
c. All portions of the CCC flow path are already in scope and STAMR for 10 CFR 54.4 (a)(2) with the exception of the heat exchanger tubes. The reviewed components are included in LRA Table 3.3.2-19-2-IP2, Conventional Closed Cooling System. See Table 3.4.2-5-1-IP2 provided in response to RAI 3.4.2-1 for a supplemental listing of the component types in scope and STAMR for this system.

Condensate System (COND)

a. The condensate system must condense the steam in the condenser and supply water from the main condenser to the feedwater pumps.

b. LRA drawings LRA-9321-2018 and LRA-9321-2025 show the majority of the system. The system flow path starts with the main condensers and includes the condensate pumps, low pressure feedwater heaters up to and including the main feedwater pumps and associated piping and valves.
c. All portions of the flow path are already in scope and STAMR for 10 CFR 54.4(a)(2) with the exception of heat exchanger tubes and the portions of the system internal to the condenser, which are normally under vacuum.

   The reviewed components are included in LRA Table 3.3.2-19-4-IP2, Condensate System. See Table 3.4.2-5-2-IP2 provided in response to RAI 3.4.2-1 for a supplemental listing of the component types in scope and STAMR for this system.

Circulating Water System (CW)

a. The circulating water system provides cooling water to the main condenser.
b. The flow path starts with the pumps at the intake structure and includes the piping and valves to and from the main condenser.
c. The components in the flow path are already in scope and STAMR for 10 CFR 54.4 (a)(2) with the exception of buried components and components at the intake structure. The reviewed components are included in LRA Table 3.3.2-19-6-IP2, Circulating Water System. See Table 3.4.2-5-3-IP2 provided in response to RAI 3.4.2-1 for a supplemental listing of the component types in scope and STAMR for this system.

City Water System (CYW)

a. The city water system provides gland seal cooling for the wash water pumps and river water service pumps and lubrication as well as cooling water for the circulating water pumps.
b. The flow path starts with the city water tanks and includes the piping and components up to the supply to the wash water pumps, river water service pumps and circulating water pumps.
c. The components in this flow path are already in scope and STAMR for 10 CFR 54.4(a)(1) or (a)(2) with the exception of the outdoor portion of the flow paths in the city water supply to the wash water pumps, river water service pumps and the backup supply to the circulating water pumps. The tanks and main headers of the city water system are STAMR as described in section 2.3.3.17 of the LRA and as shown by the highlighting on drawings LRA-192505, LRA-92506 and LRA-193183 and identified in LRA Table 3.3.2-17-IP2, City Water. The portions of the city water system that are internal to structures and subject to aging management review for CFR 54.4(a)(2) are identified in LRA Table 3.3.2-19-7-IP2, City Water System. Table 3.4.2-5-4-IP2 provides, in response to RAI 3.4.2-1, a supplemental listing of the component types in scope and STAMR for this system.

Wash Water System (WW)

a. The function of the wash water system is to maintain a suction source for the circulating water pumps by cleaning the traveling screens, as needed.
b. The wash water system including the pumps and all components in the flow path to the screens were conservatively included in the AFW pump room fire event review so the option to clean the travelling screens could be completed if necessary.
c. No portions of this flow path were already in scope and STAMR for 10 CFR 54.4(a)(1) or (a)(2). Table 3.4.2-5-5-IP2 provided in response to RAI 3.4.2-1 lists the component types in scope and STAMR for this system.

Feedwater System (FW)

a. The function of the feedwater system is to supply water to the steam generators.
b. Drawing LRA 9321-2019 depicts the FW system. The feedwater system provides the flow path from the discharge of the main feedwater pumps to the steam generators.
c. All portions of the flow path are already in scope and STAMR for 10 CFR 54.4(a)(1) or (a)(2) with the exception of heat exchanger tubes. The reviewed components are evaluated in LRA Tables 3.3.2-19-12-IP2, Feedwater System and 3.4.2-2-IP2, Main Feedwater. Table 3.4.2-5-6-IP2 provides in response to RAI 3.4.2-1 a supplemental listing of the component types in scope and STAMR for this system.

Instrument Air System (IA)

a. The instrument air system is to provide compressed air to the secondary side air operated components to support the supply of feedwater to the steam generators.
b. The IA system can be seen primarily on drawing LRA-9321-2036. The portions of the system starting with the air compressors up to the components that require instrument air during the event constitute the flow path required for the fire in the AFW pump room.
c. Many of the main components in the system were identified as STAMR for the 10 CFR 54.4(a)(2) review, but the 10 CFR 54.4(a)(2) review did not include heat exchanger tubes or the supply lines to some of the non-safety related components. The reviewed components are evaluated in LRA Table 3.3.2-19-18-IP2, Instrument Air System. See Table 3.4.2-5-7-IP2 provided in response to RAI 3.4.2-1 for a supplemental listing of the component types in scope and STAMR for this system.

Instrument Air Closed Cooling System (IACC)

a. The IACC system provides heat removal for the instrument air compressors and aftercoolers.
b. The IACC system can be seen on drawing LRA-9321-2722. The system consists of a separate closed loop cooling water system consisting of two small pumps, valves, piping, and heat exchangers, which supplies cooling water to the instrument air compressors and aftercoolers and rejects that heat to the service water system. The entire system is credited during the fire in the AFW pump room event.
c. All portions of the flow path are already in scope and STAMR for 10 CFR 54.4(a)(1) or (a)(2), however, the heat transfer function is not identified for the heat exchanger tubes. Evaluation of the IACC heat exchanger for pressure boundary is included in LRA Table 3.3.2-2-IP2, Service Water System. The reviewed components are evaluated in LRA Table 3.3.2-19-19-IP2, Instrument Air Closed Cooling System. See Table 3.4.2-5-8-IP2 provided in response to RAI 3.4.2-1 for a supplemental listing of the component types in scope and STAMR for this system that includes the heat transfer function for the heat exchanger tubes.

Service Water System (SW)

a. The service water system provides cooling to the IACC system and the main feedwater pump lube oil coolers, bearing lubrication and cooling water to the circulating water pumps, and supplies traveling screen wash water.
b. The SW system is shown on LRA drawings LRA-9321-2028, LRA-9321-2722, LRA-209762, LRA-235117, LRA-235122, LRA-226037, LRA-226038 and LRA-242687. The service water system flow path for the AFW pump room fire event starts with the SW pumps and includes the components in the flow path up to the cooled subcomponents described above.
c. The safety-related portions of the system are in scope and STAMR and included in Table 3.3.2-2-IP2, Service Water System. The portion of the system supplying cooling water to the IACC heat exchanger and main feedwater pump lube oil coolers is in scope and STAMR for 10 CFR 54.4(a)(2). These components are evaluated in LRA Table 3.3.2-19-39-IP2, Service Water System. The SW system supply to traveling screen wash water and bearing lubrication as well as cooling water to the circulating water pumps was not included in scope for 10 CFR 54.4(a)(2). See Table 3.4.2-5-9-IP2 provided in response to RAI 3.4.2-1 for a supplemental listing of the remaining component types in scope and STAMR for this system.

Lube Oil System (LO)

a. The lube oil system supplies lube oil for governing and lubricating the main feedwater pumps and turbines from a common oil reservoir located below the two main feedwater pump units.
b. The entire lube oil subsystem supports the system flow path including the pumps, heat exchangers, piping and valves.
c. The system is in scope and STAMR for 10 CFR 54.4(a)(2) with the exception of the heat exchanger tubes. The reviewed components are evaluated in LRA Table 3.3.2-19-22-IP2, Lube Oil System. See Table 3.4.2-5-10-IP2 provided in response to RAI 3.4.2-1 for a supplemental listing of the component types in scope and STAMR for this system.

Main Steam System (MS)

a. The main steam system provides the steam flow path for heat removal from the steam generators and supplies the steam to the main feedwater pump turbines and gland seals.
b. The system flow path starts at the steam generators and includes the components in the main steam lines and piping up to the main condenser, the main feedwater pump turbine, and the gland seal supply.
c. All portions of the flow path are already in scope and STAMR for 10 CFR 54.4(a)(1) or (a)(2). The majority of the system is included in scope and STAMR for 10 CFR 54.4(a)(1) as shown by the highlighting on LRA drawing 227780 and evaluated in LRA Table 3.4.2-1-IP2, Main Steam System. The remaining components in the flow path to support the main feedwater pump operation during the AFW pump room fire event are in scope and STAMR for 10 CFR 54.4(a)(2). These components are evaluated in LRA Table 3.3.2-19-23-IP2, Main Steam System.

Water Treatment Plant System (WTP)

a. The water treatment plant system supplies makeup to the condensate system.
b. The make up flow path is from the IP1 condensate storage tanks to the interface with the condensate system.
c. All of the components in the flow path are in scope and STAMR for 10 CFR 54.4(a)(2) with the exception of the few outdoor components. The reviewed components are evaluated in LRA Table 3.3.2-19-43-IP2, Water Treatment Plant. The remaining portions of the WTP system that do not normally support IP2 plant operation but support the AFW pump room fire event were evaluated with the results provided in response to RAI 2.3A.4.2-1 (correspondence NL-08-005 dated January 4, 2008).

River Water Service System (RW)

a. The river water system supplements the IP2 service water pumps in supplying cooling water for non-essential service water loads and providing cooling water to the fresh water cooling system.
b. The system flow path starts with the river water pumps and includes all components in the flow path up to the intertie to the IP2 SW system and the piping to and from the fresh water cooling heat exchangers.
c. The portion of the system credited during the AFW pump room fire event is in scope for 10 CFR 54.4(a)(2) and STAMR with the exception of the outdoor components. The reviewed components are evaluated in LRA Table 3.3.2-19-32-IP2, River Water Service System. See Table 3.4.2-5-11-IP2 provided in response to RAI 3.4.2-1 for a supplemental listing of the component types in scope and STAMR for this system.

Fresh Water Cooling System (FWC)

a. The fresh water cooling system provides cooling to the Unit 1 air compressors.
b. The system flow path starts at the FWC tank continues through the FWC pumps and FWC heat exchangers and on to the components in the supply to and return from the Unit 1 air compressors.
c. The portion of the system credited during the AFW pump room fire event is in scope and STAMR for 10 CFR 54.4(a)(2) with the exception of the heat exchanger tubes. The reviewed components are evaluated in LRA Table 3.3.2-19-13-IP2, Fresh Water Cooling System. See Table 3.4.2-5-12-IP2 provided in response to RAI 3.4.2-1 for a supplemental listing of the component types in scope and STAMR for this system.

IP1 Station Air System (SA)

a. The IP1 station air system provides an alternate supply of air to the IP2 instrument air system.
b. The system flow path includes the portion of the system starting from the IP1 air compressors up to the connections to the IP2 instrument air system.
c. This system was not in scope and STAMR for 10 CFR 54.4(a)(1) or (a)(2). See Table 3.4.2-5-13-IP2 provided in response to RAI 3.4.2-1 for a listing of the component types in scope and STAMR for this system.

Additional LRA Clarifications

1. LRA Section 2.2, seventh paragraph (page 2.2-2) discussion of highlighted LRA drawings should be clarified as shown (underline – added, strikethrough – deleted):

   "Components subject to aging management review are highlighted on license renewal drawings, with the exception of components in scope for 10 CFR

54.4(a)(2) for a physical interaction with other equipment that could prevent accomplishment of a safety function and the components required for the AFW pump room fire event described in section 2.3.4.5."

2. The description originally provided for the LRA Section 2.3.4.5, Auxiliary Steam, second paragraph, (page 2.3-340) incorrectly describes the system function during the AFW pump room fire event. The second paragraph is replaced with:

   "For the AFW pump room fire event, auxiliary steam supports the gland seal steam supply."

RAI 3.4.2-1

In LRA Section 3.4.2, the applicant summarizes its AMR results for the IP2 auxiliary feedwater pump room fire event. In the LRA, the applicant states that:
The components in the systems required to supply feedwater to the steam generators during the short duration of the fire event are in service at the time the event occurs or their availability is checked daily. Therefore, integrity of the systems and components required to perform post-fire intended functions for at least one hour is continuously confirmed by normal plant operation. During the event these systems and components must continue to perform their intended functions to supply feedwater to the steam generators for a minimum of one hour.

Significant degradation that could threaten the performance of the intended functions will be apparent in the period immediately preceding the event and corrective action will be required to sustain continued operation. For the minimal one hour period that these systems would be required to provide make up to the steam generators, further aging degradation that would not have been apparent prior to the event is negligible. Therefore, no aging effects are identified, and no Summary of Aging Management Review table is provided.

Section 54.21(a)(1) of 10 CFR requires that for those systems, structures, and components within the scope of license renewal, as delineated in § 54.4, applicants must identify and list those structures and components subject to an aging management review. Additionally, Section 54.21(a)(3), requires that for each structure and component identified in paragraph 54.21(a)(1), applicants must demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation. Based on the information contained in the LRA, Entergy has not demonstrated that the effects of aging for passive, long-lived components within the systems credited for providing flow to the steam generators during the fire event will be adequately managed.

For those systems, or portions thereof, that are identified in response to RAI 2.3.4.5-2, part c, the staff requests that the applicant provide a list of passive, long-lived component types, material, environment, and aging effect combinations, and the programs that will be used to manage the aging effects.

Response for RAI 3.4.2-1

As indicated in LRA section 2.3.4.5, normal plant operation demonstrates the ability of secondary systems to supply feedwater to the steam generators. This includes the systems that function to supply feedwater to the steam generators in the unlikely event of a fire in the AFW pump room. The function of supporting safe shutdown in the event of a fire in the auxiliary feed pump room is confirmed on an ongoing basis since the required SSCs are performing their intended functions under design basis conditions during normal operation. Unlike the case for most safety-related equipment, the conditions under which these SSCs must perform their intended functions are the same conditions under which they operate during the course of normal plant operations. Performance of intended functions during normal plant operation demonstrates that the systems and components can perform those functions for one hour in the event of a fire in the auxiliary feedwater pump room.

The response to RAI 2.3A.4.5-2 describes the functions and flow paths of the systems credited for the AFW pump room fire event.

The following tables provide clarifying details regarding the passive, long-lived component types, materials, environments, aging effects and programs for SSCs that support the AFW pump room fire event that were not already included in scope and STAMR for 10CFR54.4(a)(1) or (a)(2).

Table 3.4.2-5-1-IP2
Conventional Closed Cooling System
Components Required to Support AFW Pump Room Fire Event
Summary of Aging Management Review

Table 3.4.2-5-1-IP2: Conventional Closed Cooling System (CCC)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat exchanger tubes	Pressure boundary and heat transfer	Copper alloy	Treated water (ext)	None	None	--	--	408
Heat exchanger tubes	Pressure boundary and heat transfer	Copper alloy	Treated water (int)	None	None	--	--	408

Table 3.4.2-5-2-IP2
Condensate System
Components Required to Support AFW Pump Room Fire Event
Summary of Aging Management Review

Table 3.4.2-5-2-IP2 Condensate System (COND)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Carbon steel	Air – indoor (ext)	None	None	--	--	408
Bolting	Pressure boundary	Stainless steel	Air – indoor (ext)	None	None	--	--	408
Expansion joint	Pressure boundary	Elastomer	Air – indoor (ext)	None	None	--	--	408
Expansion joint	Pressure boundary	Elastomer	Steam (int)	None	None	--	--	408
Expansion joint	Pressure boundary	Elastomer	Air – indoor (ext)	None	None	--	--	408
Expansion joint	Pressure boundary	Elastomer	Treated water (int)	None	None	--	--	408
Heat exchanger shell	Pressure boundary	Carbon steel	Treated water (int)	None	None	--	--	408
Heat exchanger shell	Pressure boundary	Carbon steel	Air – indoor (ext)	None	None	--	--	408
Heat exchanger shell	Pressure boundary	Carbon steel	Steam (ext)	None	None	--	--	408
Heat exchanger tubes	Pressure boundary and heat transfer	Titanium	Steam (ext)	None	None	--	--	408

Table 3.4.2-5-2-IP2 Condensate System (COND)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat exchanger tubes	Pressure boundary and heat transfer	Titanium	Raw water (int)	None	None	--	--	408
Heat exchanger tubes	Pressure boundary and heat transfer	Copper alloy	Treated water (int)	None	None	--	--	408
Heat exchanger tubes	Pressure boundary and heat transfer	Copper alloy	Lube oil (ext)	None	None	--	--	408
Heat exchanger tubes	Pressure boundary	Stainless steel	Steam (ext)	None	None	--	--	408
Heat exchanger tubes	Pressure boundary	Stainless steel	Treated water (int)	None	None	--	--	408
Heat exchanger tubes	Pressure boundary	Titanium	Treated water (int)	None	None	--	--	408
Heat exchanger tubes	Pressure boundary	Titanium	Steam (ext)	None	None	--	--	408
Piping	Pressure boundary	Carbon steel	Treated water (int)	None	None	--	--	408
Piping	Pressure boundary	Carbon steel	Air – indoor (ext)	None	None	--	--	408
Sight glass	Pressure boundary	Carbon steel	Air – indoor (ext)	None	None	--	--	408
Sight glass	Pressure boundary	Carbon steel	Treated water (int)	None	None	--	--	408

Table 3.4.2-5-2-IP2 Condensate System (COND)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Sight glass	Pressure boundary	Glass	Air – indoor (ext)	None	None	--	--	408
Sight glass	Pressure boundary	Glass	Treated water (int)	None	None	--	--	408
Thermowell	Pressure boundary	Carbon steel	Air – indoor (ext)	None	None	--	--	408
Thermowell	Pressure Boundary	Carbon steel	Treated water (int)	None	None	--	--	408
Thermowell	Pressure boundary	Stainless steel	Air – indoor (ext)	None	None	--	--	408
Thermowell	Pressure boundary	Stainless steel	Treated water (int)	None	None	--	--	408
Tubing	Pressure boundary	Stainless steel	Treated water (int)	None	None	--	--	408
Tubing	Pressure boundary	Stainless steel	Air – indoor (ext)	None	None	--	--	408
Valve body	Pressure boundary	Carbon steel	Treated water (int)	None	None	--	--	408
Valve body	Pressure boundary	Carbon steel	Air – indoor (ext)	None	None	--	--	408
Valve body	Pressure boundary	Stainless steel	Treated water (int)	None	None	--	--	408
Valve body	Pressure boundary	Stainless steel	Air – indoor (ext)	None	None	--	--	408

Table 3.4.2-5-3-IP2
Circulating Water System
Components Required to Support AFW Pump Room Fire Event
Summary of Aging Management Review

Table 3.4.2-5-3-IP2 Circulating Water System (CIRC)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	None	None	--	--	408
Bolting	Pressure boundary	Carbon steel	Soil (ext)	None	None	--	--	408
Expansion Joint	Pressure boundary	Elastomer	Raw water (int)	None	None	--	--	408
Expansion Joint	Pressure boundary	Elastomer	Air –outdoor (ext)	None	None	--	--	408
Piping	Pressure boundary	Carbon steel	Soil (ext)	None	None	--	--	408
Piping	Pressure boundary	Carbon steel	Air outdoor (ext)	None	None	--	--	408
Piping	Pressure boundary	Carbon steel	Raw water (int)	None	None	--	--	408
Pump casing	Pressure boundary	Carbon steel	Air-outdoor (ext)	None	None	--	--	408
Pump casing	Pressure boundary	Carbon steel	Raw water (int)	None	None	--	--	408

Table 3.4.2-5-4-IP2
City Water System
Components Required to Support AFW Pump Room Fire Event
Summary of Aging Management Review

Table 3.4.2-5-4-IP2 City Water System (CYW)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Carbon steel	Air – indoor (ext)	None	None	--	--	408
Bolting	Pressure boundary	Stainless steel	Air – indoor (ext)	None	None	--	--	408
Bolting	Pressure boundary	Carbon steel	Air – outdoor (ext)	None	None	--	--	408
Bolting	Pressure boundary	Stainless steel	Air – outdoor (ext)	None	None	--	--	408
Flex hose	Pressure boundary	Stainless steel	Air-indoor (ext)	None	None	--	--	408
Flex hose	Pressure boundary	Stainless steel	Treated water (int)	None	None	--	--	408
Piping	Pressure boundary	Carbon steel	Air-outdoor (ext)	None	None	--	--	408
Piping	Pressure boundary	Carbon steel	Air-indoor (ext)	None	None	--	--	408
Piping	Pressure boundary	Carbon steel	Treated water (int)	None	None	--	--	408
Piping	Pressure boundary	Stainless steel	Air-indoor (ext)	None	None	--	--	408
Piping	Pressure boundary	Stainless steel	Air-outdoor (ext)	None	None	--	--	408

Table 3.4.2-5-4-IP2 City Water System (CYW)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Treated water (int)	None	None	--	--	408
Sight glass	Pressure boundary	Carbon steel	Air-outdoor (ext)	None	None	--	--	408
Sight glass	Pressure boundary	Carbon steel	Treated water (int)	None	None	--	--	408
Sight glass	Pressure boundary	Glass	Air-outdoor (ext)	None	None	--	--	408
Sight glass	Pressure boundary	Glass	Treated water (int)	None	None	--	--	408
Strainer housing	Pressure boundary	Carbon steel	Air-indoor (ext)	None	None	--	--	408
Strainer housing	Pressure boundary	Carbon steel	Treated water (int)	None	None	--	--	408
Strainer housing	Pressure boundary	Stainless steel	Air-indoor (ext)	None	None	--	--	408
Strainer housing	Pressure boundary	Stainless steel	Treated water (int)	None	None	--	--	408
Tubing	Pressure boundary	Stainless steel	Treated water (int)	None	None	--	--	408
Tubing	Pressure boundary	Stainless steel	Air – outdoor (ext)	None	None	--	--	408
Tubing	Pressure boundary	Stainless steel	Air – indoor (ext)	None	None	--	--	408
Valve body	Pressure boundary	Carbon steel	Treated water (int)	None	None	--	--	408

Table 3.4.2-5-4-IP2 City Water System (CYW)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Carbon steel	Air – outdoor (ext)	None	None	--	--	408
Valve body	Pressure boundary	Carbon steel	Air – indoor (ext)	None	None	--	--	408
Valve body	Pressure boundary	Stainless steel	Treated water (int)	None	None	--	--	408
Valve body	Pressure boundary	Stainless steel	Air – outdoor (ext)	None	None	--	--	408
Valve body	Pressure boundary	Stainless steel	Air – indoor (ext)	None	None	--	--	408

**Table 3.4.2-5-5-IP2
Wash Water System
Components Required to Support AFW Pump Room Fire Event
Summary of Aging Management Review**

Table 3.4.2-5-5-IP2 Wash Water System (WW) Components

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Carbon steel	Air-outdoor (ext)	None	None	--	--	408
Bolting	Pressure boundary	Stainless steel	Air-outdoor (ext)	None	None	--	--	408
Expansion joint	Pressure boundary	Elastomer	Air-outdoor (ext)	None	None	--	--	408
Expansion joint	Pressure boundary	Elastomer	Raw water (int)	None	None	--	--	408
Flex hose	Pressure boundary	Stainless steel	Air-outdoor (ext)	None	None	--	--	408
Flex hose	Pressure boundary	Stainless steel	Raw water (int)	None	None	--	--	408
Nozzles	Pressure boundary	Carbon steel	Air-outdoor (ext)	None	None	--	--	408
Nozzles	Pressure boundary	Carbon steel	Raw water (int)	None	None	--	--	408
Piping	Pressure boundary	Carbon steel	Air-outdoor (ext)	None	None	--	--	408
Piping	Pressure boundary	Carbon steel	Raw water (int)	None	None	--	--	408

Table 3.4.2-5-5-IP2 Wash Water System (WW) Components

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Air-outdoor (ext)	None	None	--	--	408
Piping	Pressure boundary	Stainless steel	Raw water (int)	None	None	--	--	408
Pump casing	Pressure boundary	Carbon steel	Air-outdoor (ext)	None	None	--	--	408
Pump casing	Pressure boundary	Carbon steel	Raw water (int)	None	None	--	--	408
Tubing	Pressure boundary	Stainless steel	Air-outdoor (ext)	None	None	--	--	408
Tubing	Pressure boundary	Stainless steel	Raw water (int)	None	None	--	--	408
Valve body	Pressure boundary	Carbon steel	Air-outdoor (ext)	None	None	--	--	408
Valve body	Pressure boundary	Carbon steel	Raw water (int)	None	None	--	--	408
Valve body	Pressure boundary	Stainless steel	Air-outdoor (ext)	None	None	--	--	408
Valve body	Pressure boundary	Stainless steel	Raw water (int)	None	None	--	--	408

Table 3.4.2-5-6-IP2
Feedwater System
Components Required to Support AFW Pump Room Fire Event
Summary of Aging Management Review

Table 3.4.2-5-6-IP2 Feedwater System (FW)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat exchanger tubes	Pressure boundary	Stainless steel	Steam (ext)	None	None	--	--	408
Heat exchanger tubes	Pressure boundary	Stainless steel	Treated water (int)	None	None	--	--	408

Table 3.4.2-5-7-IP2
Instrument Air System
Components Required to Support AFW Pump Room Fire Event
Summary of Aging Management Review

Table 3.4.2-5-7-IP2 Instrument Air System (IA)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Carbon steel	Air-outdoor (ext)	None	None	--	--	408
Bolting	Pressure boundary	Stainless steel	Air-outdoor (ext)	None	None	--	--	408

Table 3.4.2-5-7-IP2 Instrument Air System (IA)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat exchanger (tubes)	Pressure boundary and heat transfer	Copper alloy	Condensation (int)	None	None	--	--	408
Heat exchanger (tubes)	Pressure boundary and heat transfer	Copper alloy	Treated Water (ext)	None	None	--	--	408
Tubing	Pressure boundary	Copper alloy	Air - indoor (ext)	None	None	--	--	408
Tubing	Pressure boundary	Copper alloy	Air - treated (int)	None	None	--	--	408
Tubing	Pressure boundary	Stainless steel	Air - indoor (ext)	None	None	--	--	408
Tubing	Pressure boundary	Stainless steel	Air - treated (int)	None	None	--	--	408
Piping	Pressure boundary	Carbon steel	Air-indoor (ext)	None	None	--	--	408
Piping	Pressure boundary	Carbon steel	Air-treated (int)	None	None	--	--	408
Piping	Pressure boundary	Stainless steel	Air-indoor (ext)	None	None	--	--	408
Piping	Pressure boundary	Stainless steel	Air-treated (int)	None	None	--	--	408
Valve body	Pressure boundary	Copper alloy	Air - indoor (ext)	None	None	--	--	408

Table 3.4.2-5-7-IP2 Instrument Air System (IA)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Copper alloy	Air - treated (int)	None	None	--	--	408
Valve body	Pressure boundary	Copper alloy >15% zn	Air - indoor (ext)	None	None	--	--	408
Valve body	Pressure boundary	Copper alloy >15% zn	Air - treated (int)	None	None	--	--	408
Valve body	Pressure boundary	Carbon steel	Air - indoor (ext)	None	None	--	--	408
Valve body	Pressure boundary	Carbon steel	Air - treated (int)	None	None	--	--	408
Valve body	Pressure boundary	Stainless steel	Air - indoor (ext)	None	None	--	--	408
Valve body	Pressure boundary	Stainless steel	Air - treated (int)	None	None	--	--	408

Table 3.4.2-5-8-IP2
Instrument Air Closed Cooling System
Components Required to Support AFW Pump Room Fire Event
Summary of Aging Management Review

Table 3.4.2-5-8-IP2 Instrument Air Closed Cooling System (IACC)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat exchanger tubes	Heat transfer	Copper > 15% Zn (inhibited)	Raw water (int)	None	None	--	--	408
Heat exchanger tubes	Heat transfer	Copper > 15% Zn (inhibited)	Treated water (ext)	None	None	--	--	408

Table 3.4.2-5-9-IP2
Service Water System
Components Required to Support AFW Pump Room Fire Event
Summary of Aging Management Review

Table 3.4.2-5-9-IP2 Service Water System (SW)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Carbon steel	Air-outdoor (ext)	None	None	--	--	408
Bolting	Pressure boundary	Stainless steel	Air-outdoor (ext)	None	None	--	--	408
Nozzles	Pressure boundary	Carbon steel	Air-outdoor (ext)	None	None	--	--	408

Table 3.4.2-5-9-IP2 Service Water System (SW)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Nozzles	Pressure boundary	Carbon steel	Raw water (int)	None	None	--	--	408
Piping	Pressure boundary	Carbon steel	Air-outdoor (ext)	None	None	--	--	408
Piping	Pressure boundary	Carbon steel	Raw water (int)	None	None	--	--	408
Piping	Pressure boundary	Stainless steel	Air-outdoor (ext)	None	None	--	--	408
Piping	Pressure boundary	Stainless steel	Raw water (int)	None	None	--	--	408
Separator	Pressure boundary	Stainless steel	Air-outdoor (ext)	None	None	--	--	408
Separator	Pressure boundary	Stainless steel	Raw water (int)	None	None	--	--	408
Tubing	Pressure boundary	Copper alloy	Air-outdoor (ext)	None	None	--	--	408
Tubing	Pressure boundary	Copper alloy	Raw water (int)	None	None	--	--	408
Tubing	Pressure boundary	Stainless steel	Air-outdoor (ext)	None	None	--	--	408
Tubing	Pressure boundary	Stainless steel	Raw water (int)	None	None	--	--	408
Valve body	Pressure boundary	Carbon steel	Air-outdoor (ext)	None	None	--	--	408
Valve body	Pressure boundary	Carbon steel	Raw water (int)	None	None	--	--	408

Table 3.4.2-5-9-IP2 Service Water System (SW)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Stainless steel	Air-outdoor (ext)	None	None	--	--	408
Valve body	Pressure boundary	Stainless steel	Raw water (int)	None	None	--	--	408

Table 3.4.2-5-10-IP2
Lube Oil System
Components Required to Support AFW Pump Room Fire Event
Summary of Aging Management Review

Table 3.4.2-5-10-IP2 Lube Oil System (LO)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat exchanger tubes	Pressure boundary and heat transfer	Titanium	Lube oil (int)	None	None	--	--	408
Heat exchanger tubes	Pressure boundary and heat transfer	Titanium	Raw water (ext)	None	None	--	--	408

Table 3.4.2-5-11-IP2
River Water Service System
Components Required to Support AFW Pump Room Fire Event
Summary of Aging Management Review

Table 3.4.2-5-11-IP2 River Water Service System (RW)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Bolting	Pressure boundary	Carbon steel	Air-outdoor (ext)	None	None	--	--	408
Bolting	Pressure boundary	Stainless steel	Air-outdoor (ext)	None	None	--	--	408
Piping	Pressure boundary	Carbon steel	Air-outdoor (ext)	None	None	--	--	408
Piping	Pressure boundary	Carbon steel	Raw water (int)	None	None	--	--	408
Pump casing	Pressure boundary	Carbon steel	Air-outdoor (ext)	None	None	--	--	408
Pump casing	Pressure boundary	Carbon steel	Raw water (int)	None	None	--	--	408
Tubing	Pressure boundary	Stainless steel	Air-outdoor (ext)	None	None	--	--	408
Tubing	Pressure boundary	Stainless steel	Raw water (int)	None	None	--	--	408
Valve body	Pressure boundary	Carbon steel	Air-outdoor (ext)	None	None	--	--	408
Valve body	Pressure boundary	Carbon steel	Raw water (int)	None	None	--	--	408
Valve body	Pressure boundary	Stainless steel	Air-outdoor (ext)	None	None	--	--	408

Table 3.4.2-5-11-IP2 River Water Service System (RW)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Stainless steel	Raw water (int)	None	None	--	--	408

Table 3.4.2-5-12-IP2
Fresh Water Cooling System
Components Required to Support AFW Pump Room Fire Event
Summary of Aging Management Review

Table 3.4.2-5-12-IP2 Fresh Water Cooling (FWC) System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat exchanger (tubes)	Heat transfer and pressure boundary	Copper alloy	Raw water (int)	None	None	--	--	408
Heat exchanger (tubes)	Heat transfer and pressure boundary	Copper alloy	Treated Water (ext)	None	None	--	--	408

Table 3.4.2-5-13-IP2
IP1 Station Air System
Components Required to Support AFW Pump Room Fire Event
Summary of Aging Management Review

Table 3.4.2-5-13-IP2 IP1 Station Air (SA) System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Bolting	Pressure boundary	Carbon steel	Air-indoor (ext)	None	None	--	--	408
Bolting	Pressure boundary	Stainless steel	Air-indoor (ext)	None	None	--	--	408
Filter housing	Pressure boundary	Carbon steel	Air-indoor (ext)	None	None	--	--	408
Filter Housing	Pressure boundary	Carbon steel	Condensation (int)	None	None	--	--	408
Piping	Pressure boundary	Carbon steel	Air-indoor (ext)	None	None	--	--	408
Piping	Pressure boundary	Carbon steel	Condensation (int)	None	None	--	--	408
Piping	Pressure boundary	Stainless steel	Air-indoor (ext)	None	None	--	--	408
Piping	Pressure boundary	Stainless steel	Condensation (int)	None	None	--	--	408
Strainer housing	Pressure boundary	Carbon steel	Air-indoor (ext)	None	None	--	--	408
Strainer housing	Pressure boundary	Carbon steel	Condensation (int)	None	None	--	--	408
Tank	Pressure boundary	Carbon steel	Air-indoor (ext)	None	None	--	--	408

Table 3.4.2-5-13-IP2 IP1 Station Air (SA) System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Tank	Pressure boundary	Carbon steel	Condensation (int)	None	None	--	--	408
Tubing	Pressure boundary	Carbon steel	Air-indoor (ext)	None	None	--	--	408
Tubing	Pressure boundary	Carbon steel	Condensation (int)	None	None	--	--	408
Tubing	Pressure boundary	Stainless steel	Air-indoor (ext)	None	None	--	--	408
Tubing	Pressure boundary	Stainless steel	Condensation (int)	None	None	--	--	408
Tubing	Pressure boundary	Copper alloy	Air-indoor (ext)	None	None	--	--	408
Tubing	Pressure boundary	Copper alloy	Condensation (int)	None	None	--	--	408
Trap	Pressure boundary	Carbon steel	Air-indoor (ext)	None	None	--	--	408
Trap	Pressure boundary	Carbon steel	Condensation (int)	None	None	--	--	408
Valve body	Pressure boundary	Carbon steel	Air-indoor (ext)	None	None	--	--	408
Valve body	Pressure boundary	Carbon steel	Condensation (int)	None	None	--	--	408
Valve body	Pressure boundary	Stainless steel	Air-indoor (ext)	None	None	--	--	408
Valve body	Pressure boundary	Stainless steel	Condensation (int)	None	None	--	--	408

Table 3.4.2-5-13-IP2 IP1 Station Air (SA) System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Copper alloy	Air-indoor (ext)	None	None	--	--	408
Valve body	Pressure boundary	Copper alloy	Condensation (int)	None	None	--	--	408

Notes for Tables 3.4.2-5-1-IP2 through 3.4.2-5-13-IP2

Plant-Specific Notes

408. Materials and environments have been identified, however there are no aging effects requiring management. The function of supporting safe shutdown in the event of a fire in the auxiliary feed pump room is confirmed since these SSCs, which are required to support this function, perform their intended functions during normal operation. Conditions under which these SSCs must perform their intended functions are the same conditions under which they operate during the course of normal plant operations. Performance of intended functions during normal plant operation demonstrates that the systems and components can perform those functions for one hour in the event of a fire in the auxiliary feedwater pump room.

RAI 3.0.3.3.3-1

In the LRA, the applicant stated that the existing program will be enhanced to include the minimum wall thickness for the new heat exchangers added to the scope of the program, and to specify that if visual examination is performed, the acceptance criterion is "no unacceptable signs of degradation." These acceptance criteria for visual examination are not clear and appear to be subjective. Therefore, the staff requests that Entergy clarify, in quantitative terms, what acceptance criteria are used for the visual examination of the heat exchanger tubes.

Response for RAI 3.0.3.3.3-1

The Heat Exchanger Monitoring Program performs visual inspections on heat exchangers that cannot be inspected by quantitative non-destructive examination due to design limitations.

Visual inspections are performed by engineers qualified by virtue of training and experience to evaluate heat exchanges conditions. Visual inspection of external portions of heat exchanger tubes focuses on detecting the extent of tube erosion, vibration wear, corrosion, pitting, fouling, and scaling.

The term "no unacceptable signs of degradation" means no indications of these aging mechanisms to the extent that the intended function of the heat exchanger could be compromised. The judgment of the qualified heat exchanger engineer is applied to make this determination based on the design requirements of the heat exchanger and considering the extent of surface roughness caused by corrosion, erosion, pitting or wear and the thickness and extent of any scale or other foreign material observed on the tubes. Any unacceptable signs of degradation will be evaluated through the corrective action process.

RAI 3.0.3.3.4-1

LRA Table B-2 identifies AMP B.1.18, Inservice Inspection Program, as a plant-specific condition monitoring program for the applications. The staff notes that Entergy has committed to enhance the "detection of aging effects" program element of the Inservice Inspection Program to revise the AMP to provide for periodic visual inspections of lubrite sliding supports used in the steam generator supports and reactor coolant pump (RCP) supports in order to confirm the absence of aging effects. Please specify (1) which aging effects and parameters will be monitored for by the visual examinations, (2) the types of visual examinations (e.g., VT-1, EVT-1, VT-2, or VT-3), (3) inspection frequency and sample size for the visual examination method that will be used to monitor for aging, (4) the acceptance criteria that will be used to evaluate the examination results, and (5) the corrective action or actions that will be implemented if the inspection results do not conform to the acceptance standard(s) for these components.

Response for RAI 3.0.3.3.4-1

The inservice inspection (ISI) program will employ visual inspections to confirm the absence of aging effects for steam generator (SG) and reactor coolant pump (RCP) lubrite sliding supports through the period of extended operation (PEO).

As described in LRA Section B.1.18, the ISI program is an existing program that encompasses requirements of ASME Code Section XI, Subsection IWF for ASME Class 1, 2, 3, and MC supports. The ISI program will be enhanced prior to the PEO to include explicit provisions for periodic inspections of the lubrite sliding supports. No aging effects requiring management have been identified for lubrite, but monitoring the surface condition of accessible surfaces will confirm the absence of age-related degradation. The inspections will be VT-3 visual examinations of SG and RCP lubrite sliding supports to determine their condition. The inspections will examine accessible surfaces of the lubrite and adjacent surfaces for wear or abnormal condition (surface roughness) that could potentially lead to lock-up or loss of function of the support. The lubrite will be examined in conjunction with Code required examinations of the support as a whole. The inspection frequency and sample size will be in accordance with the requirements of ASME Code Section XI, Subsection IWF. The supports must meet the acceptance standards described in IWF-3410(a), which includes no scoring or roughness on sliding surfaces. Any of the conditions described in IWF-3410(a) shall be corrected or evaluated for acceptance in accordance with IWF-3122.2 and IWF-3122.3, respectively. Corrective actions for this program will be administered under the site QA program which meets requirements of 10 CFR Part 50, Appendix B.

RAI 3.0.3.3.4-2

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

Response for RAI 3.0.3.3.4-2

The content of the "corrective actions" program element means that Entergy will implement the corrective action provisions in the ASME Code Section XI, Subsections IWA, IWB, IWC, IWD, and IWF that are applicable to the component Code Class in the applicable ASME Code Section XI edition of record.

RAI 3.0.3.3.7-1

LRA Table B-2 identifies AMP B.1.29, Periodic Surveillance and Preventative Maintenance Program, as an existing, plant-specific condition monitoring program for the LRA. NUREG-1800, Revision 1, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR), Appendix A, Section A.1.2.2 states that aging management programs for license renewal applications (LRAs) are to be defined in terms of the 10 program elements that are provided in Table A-1 of the same appendix.

The staff notes that the applicant plans to enhance the "scope of program," "parameters monitored," "detection of aging effects," and "acceptance criteria" program elements for this AMP to develop the program activities in the future (Commitment 21). Technical Specification (TS) 5.5.2 for IP2 and TS 5.5.2 for IP3 provide TS preventative maintenance and surveillance requirements.

1. The staff requests that Entergy supplement the "scope of program" program element to clearly identify the systems and components that are within the scope of this AMP.

2. The "detection of aging effects" program element did not clearly establish which type of non-visual NDE method (volumetric examination by UT, RT, or ET or surface examination by MT or PT) or visual method (i.e., EVT-1, VT-1, VT-2, or VT-3) would be credited for each of the aging effects that the program monitors for. In addition, it is not clear whether flexing of the elastomeric components in the circulating water system and emergency diesel generator exhaust system would be coupled to the visual examinations of the components, as it was proposed for other elastomeric components within the scope of the AMP. The staff requests a more definitive discussion on the specific inspection methods (UT, RT, ET, EVT-1, VT-1, VT-2, or VT-3) to detect the parameters that are associated with the aging effects the AMP monitors for. The staff also requests that Entergy clarify whether physical manipulation (i.e., flexing) of the elastomeric components in the circulating water system and emergency diesel generator exhaust system are credited under the AMP.

3. The "monitoring and trending" program element for the AMP did not provide any discussion on how the data from the inspections performed under the "detection of aging effects" program element would be collected, quantified, or evaluated against applicable acceptance criteria, and used to make predictions related to degradation growth or to schedule re-inspections of the components. The staff requests a more definitive discussion on how the inspection results or physical manipulation (flexing) results (for elastomers) will be collected and quantified, or evaluated against applicable acceptance criteria, and used to make predictions related to degradation growth or to schedule reinspections or repairs of the components.

4. The "acceptance criteria" program element for the AMP only states that "acceptance criteria are defined in specific inspection and testing procedures and that these acceptance criteria include appropriate temperature, no significant wear, corrosion, cracking, change in material properties (for elastomers), and significant fouling based on applicable intended functions established by plant design basis. The program element discuss does not clearly identify the quantitative or qualitative criteria that will be used to assess the inspection results or reference the regulatory-based documents or standards that contain these criteria. The staff requests a clarification on the specific quantitative or qualitative acceptance criteria that will be used to evaluate the results of the specific inspection methods or physical manipulation methods (for elastomers) that are implemented under this AMP.

5. With respect to operating experience and the discussion on the NaOH tanks and recirculation pumps, clarify whether the term "no deficiencies" means that no evidence of loss of material (by corrosion, erosion, wear, or other mechanisms) was detected in the components or whether the meaning is that some amount of age-related degradation had been detected in the components and the amount of cracking or loss of material (wall loss) was found to be acceptable when compared to appropriate acceptance standards.

With respect to the discussion on the IP2 and IP3 emergency diesel generators, the security diesel generator, and the IP3 Appendix R fire protection diesel generator, clarify whether the statements "no unacceptable loss of material" and "no significant corrosion or wear" mean that no loss of material (by corrosion, erosion, wear, or other mechanisms) was detected in the components or that some loss of material was detected in the components and the amount of loss of material was found to be acceptable when compared to appropriate acceptance standards. If some degradation was detected in these components and the amount of degradation was in conformance with the applicable acceptance criteria, clarify whether the scope of the AMP included appropriate reinspections of the components in order to account for potential degradation of the components.

Response for RAI 3.0.3.3.7-1

1. Systems and components within the scope of Periodic Surveillance and Preventive Maintenance Program are identified in the program description of LRA Section B.1.29.

2. The program uses established NDE techniques, including visual, volumetric (RT or UT), and surface techniques performed by qualified personnel. Visual inspection is used only when the potential aging effect can be detected by direct surface examination. The inspection and test techniques have a demonstrated history of effectiveness in detecting the aging effect of concern. For new inspection activities implemented prior to the period of extended operation, selection of the specific type of examination technique will be based on the configuration, materials, aging effects and accessibility of the components. The following table provides appropriate examination techniques for specific aging effects and mechanisms.

Parameters Monitored and Inspection Methods for Specific Aging Effects and Mechanisms			
Aging Effect	**Aging Mechanism**	**Parameter Monitored**	**Inspection Method**
Loss of Material	Crevice Corrosion	Surface condition or Wall thickness	Visual (VT-1 or equivalent) or Volumetric (RT or UT)
Loss of Material	Galvanic Corrosion	Surface condition or Wall thickness	Visual (VT-3 or equivalent) or Volumetric (RT or UT)
Loss of Material	General Corrosion	Surface condition or Wall thickness	Visual (VT-3 or equivalent) or Volumetric (RT or UT)
Loss of Material	MIC	Surface condition or Wall thickness	Visual (VT-3 or equivalent) or Volumetric (RT or UT)
Loss of Material	Pitting Corrosion	Surface condition or Wall thickness	Visual (VT-1 or equivalent) or Volumetric (RT or UT)
Loss of Material	Erosion	Surface condition or Wall thickness	Visual (VT-3 or equivalent) or Volumetric (RT or UT)
Cracking	SCC or Cyclic Loading	Cracks	Enhanced Visual (VT-1 or equivalent) or Volumetric (RT or UT)
Cracking (for elastomers)		Cracks	Visual (VT-3 or equivalent)
Change in Material Properties (for elastomers)		Hardening and Cracks	Visual (VT-3 or equivalent)

Manual flexing of the elastomeric components in the circulating water system and emergency diesel generator exhaust system are new activities within this program. The pertinent text of LRA Section B.1.29 Periodic Surveillance and Preventative Maintenance Program is revised as follows to explicitly specify manually flexing elastomeric components.

(underline – added, strikethrough – deleted)

Emergency diesel generators	Visually inspect both inside and outside surfaces of elastomer duct flexible connections on the intake portion of EDG duct. <u>Manually flex these connections.</u>

Nonsafety-related systems affecting IP2 safety-related systems	Use visual or other NDE techniques to inspect inside and outside surfaces of a representative sample of circulating water system elastomer flexible piping connections<u>, and manually flex these connections,</u> to manage loss of material and cracking and change in material properties.

Nonsafety-related systems affecting IP3 safety-related systems	Use visual or other NDE techniques to inspect inside and outside surfaces of a representative sample of circulating water system elastomer flexible piping connections<u>, and manually flex these connections,</u> to manage loss of material and cracking and change in material properties.

3. The initial periodicity of inspections and manual flexing are based on vendor recommendations, industry guidance, input from other Entergy nuclear sites, and IPEC-specific operating experience. Results of these inspections and manual flexing are collected as part of the work control process. Any indications or relevant conditions of degradation are reported and submitted for evaluation under the corrective action program. This evaluation is performed against criteria which ensure that the structure or component intended function(s) are maintained under all current licensing basis design conditions during the period of extended operation.

Results of these inspections and manual flexing are trended by an assigned "responsible engineer". If a potential need for a change in scope or frequency of inspections is indicated based on identified patterns of degradation, a preventive maintenance change request is processed.

4. Any indications or relevant conditions of degradation are reported and submitted for further evaluation as part of the corrective action program. This evaluation is performed against criteria which ensure that the structure or component intended function(s) are maintained under all current licensing basis design conditions during the period of extended operation. These criteria include <u>no</u> unacceptable wear, corrosion, cracking, change in material properties (for elastomers), or significant fouling. Specific quantitative or qualitative criteria for acceptability are contained in manufacturer information or vendor manuals for some individual components. The engineering review process is used in situations where appropriate manufacturer data is unavailable.

5. The inspections of the IP3 sodium hydroxide (NaOH) storage tank, IP2 and IP3 recirculation pumps, IP2 and IP3 emergency diesel generators, the security generator, and the IP3 Appendix R fire protection diesel generator listed in LRA Section B.1.29 found no evidence of loss of material.

RAI 3.1.2.2.7.2-1

Part A - The staff notes that the Inservice Inspection Program (as given in LRA Section B.1.18) is credited, in part, as an acceptable plant-specific condition monitoring program for the management of cracking in ASME Code Class 1 components, including ASME Code Class 1 cast austenitic stainless steel (CASS) components. However, the staff also notes that the inspections credited under this program might be either ultrasonic test (UT) examinations or enhanced VT-1 visual examinations. If UT examinations are credited for aging management of reduction of fracture toughness in the CASS components, clarify how the UT technique selected for the examination will be capable of differentiating between UT signals that derive from flaws or cracks in the CASS materials from those that derived from UT background noise signals as a result of the complexity of the CASS microstructure or component geometry.

Part B - The staff determined that Entergy credits its Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program in part to manage cracking in the non-ASME Code Class CASS pressurizer spray head. The staff also notes that the applicant's program includes a flaw evaluation methodology for CASS components that are susceptible to thermal aging embrittlement, and that alternatively, this AMP may credit UT or enhanced VT-1 visual examinations as an indirect basis for managing loss/reduction of fracture toughness as a result of thermal aging. However, the staff notes that the applicant's program is not specifically credited for the management of cracking in CASS components. The staff requests that Entergy justify its basis for crediting AMP B.1.37, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program, to manage and detect cracking in the CASS pressurizer spray heads at IP2 and IP3, particularly when GALL AMP XI.M12 only credits this type of program for management of reduction of fracture toughness in CASS components and when the program may not actually be performing inspections of these components (i.e., the program has the option only to do the flaw tolerance evaluation without implementation of either a UT or EVT-1 examination).

Response for RAI 3.1.2.2.7.2-1

Part A

Current volumetric examination methods, including ultrasonic (UT), are not adequate for reliable detection and evaluation of cracking in CASS components. Therefore, UT examinations are not credited for use in aging management of reduction of fracture toughness in CASS components at IPEC.

Part B

In IPEC LRA Tables 3.1.2-3-IP2 and 3.1.2-3-IP3, the pressurizer spray heads were compared to the CASS piping, piping components, and piping elements of NUREG-1801 Vol. 2 Rev. 1 line item IV.C2-3. The Water Chemistry Control – Primary and Secondary Program, which is consistent with NUREG-1801, is credited for aging management. The One-Time Inspection

Program will be used to verify the effectiveness of the Water Chemistry Control – Primary and Secondary Program for management of cracking due to stress corrosion as stated in LRA section B.1.27. Listing the Thermal Aging Embrittlement of CASS Program on the line item for cracking may be unnecessary, but was included to demonstrate consistency with NUREG-1801 Item IV.C-3, which recommends a plant-specific program to address thermal aging embrittlement.

Water chemistry and the One-Time Inspection Program alone are recommended in NUREG-1801 Item IV.C2-17 to address cracking in stainless steel pressurizer spray heads. Inclusion of the Thermal Aging Embrittlement of CASS Program to address reduction of fracture toughness is appropriate. The Thermal Aging Embrittlement of CASS Program is closely related to cracking in that it manages reduction of fracture toughness through examinations that detect and size cracks or by flaw tolerance evaluation to demonstrate the material has adequate toughness to resist crack propagation. Under Parameters Monitored/Inspected for XI.M12, NUREG-1801 states that "...loss of fracture toughness is of consequence only if cracks exist)."

For the non-Class 1, non-pressure boundary spray head, the credited aging management programs provide reasonable assurance that the effects of aging will be adequately managed to ensure the spray head remains capable of performing its intended function.

RAI 3.1.2-1 Nickel Alloy AMRs

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

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

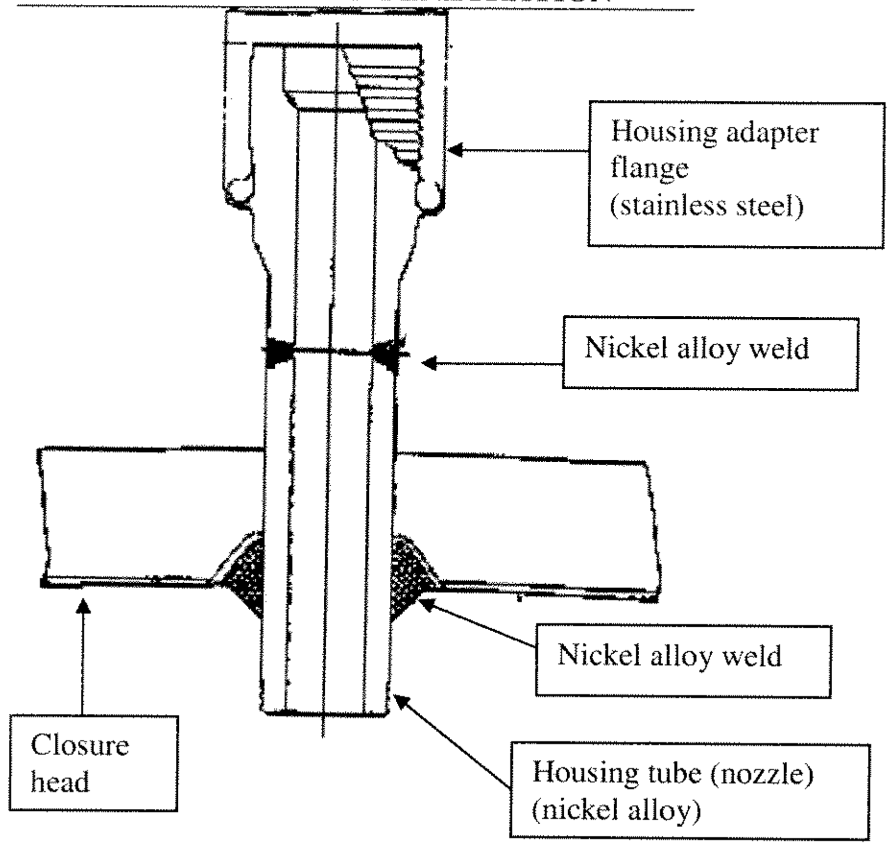
Part C - AMRs of LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3, which pertain to the management of cracking in the steam generator (SG) primary nozzle closure rings, credit only the Water Chemistry Control Program to manage cracking of the components. GALL Report Table IV.D1, line item D1-1 for these components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

Response for RAI 3.1.2-1

Part A – (1) control rod drive (CRD) housing-CRD nozzle welds

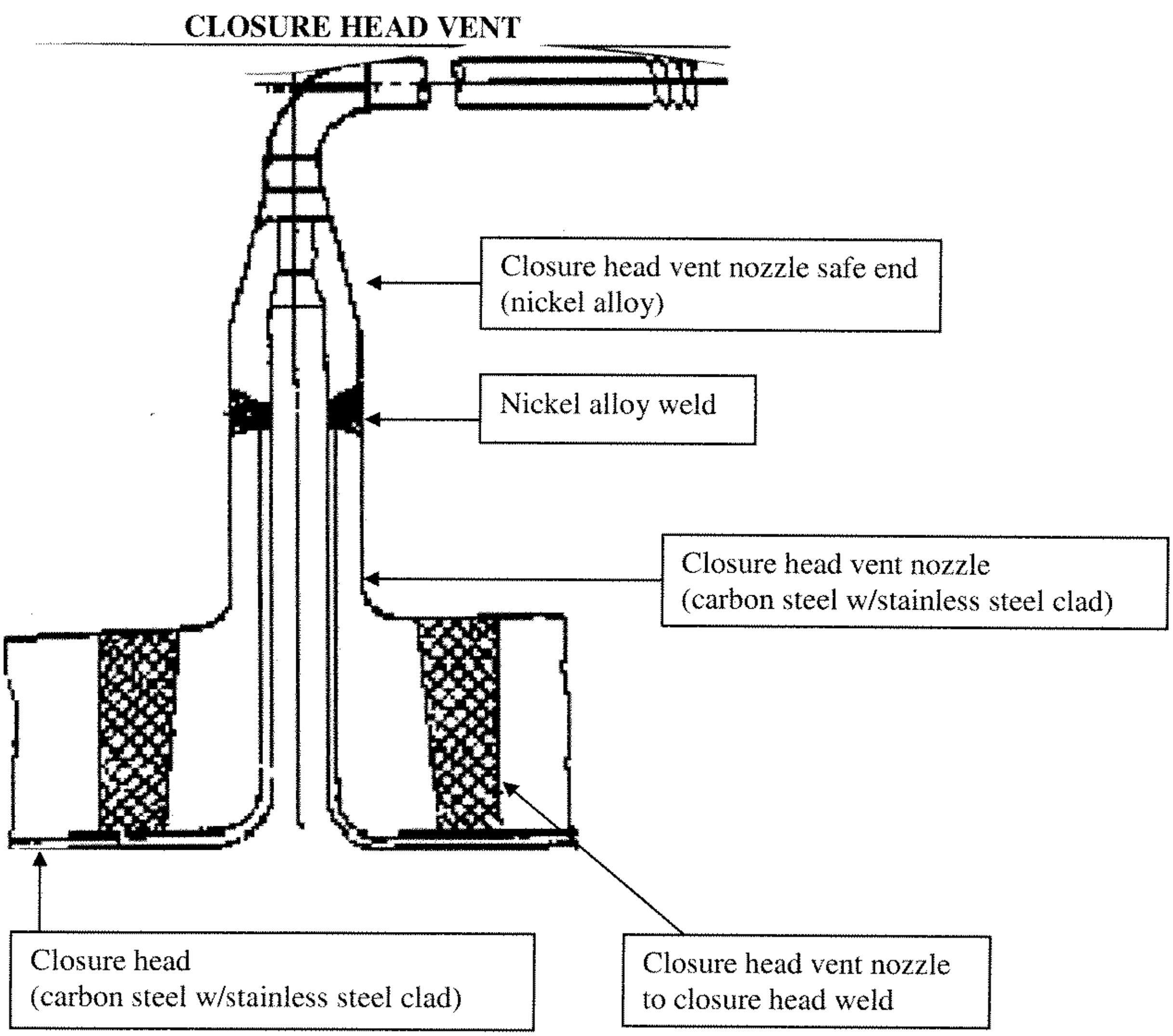
The reactor vessel closure head CRDM housing tubes (nozzles) for IP2 and IP3 are fabricated from nickel-based alloy. The nozzles penetrate the closure head. These nozzles are attached to the head with partial penetration nickel alloy welds. A stainless steel housing adapter flange is welded to the top of each nozzle. These housing adapter flanges are machined forgings onto which the CRDMs, instrumentation port female flanges, capped latch housings, and head adapter plugs/caps are threaded and seal-welded. The following figure provides details of the penetration.

CONTROL ROD DRIVE HEAD PENETRATION



(2) upper reactor vessel closure head (RVCH) head vent nozzle-to-RVCH welds

The reactor vessel closure heads are each penetrated by a head vent nozzle. The steel vent nozzle is welded to the steel closure head and the entire assembly is clad with stainless steel. There is no nickel alloy in the nozzle to head joint. A nickel alloy safe end is welded to the vent nozzle with a nickel alloy weld. The following figure provides details of the penetration.



(3) CRD housing penetration core exit thermocouple nozzle assembly components.

The CETNA utilize the CRD nozzle penetrations as shown in part A. A CET head port adaptor is connected to the penetration housing adapter flange, and then connected to the CETNA assembly via a conoseal joint. All CETNA assemblies are sealed to the CET columns with Grafoil seals using a compression collar and hold down nut with no welds. As shown in the LRA tables, the CETNA are constructed of stainless steel.

Part B

The IP2 and IP3 reactor vessels do not have bottom head drains. The bottom head penetrations provide access into the reactor vessel core for the bottom-mounted instrumentation (BMI). Each bottom head penetration consists of a tubular member made of nickel based alloy. Bottom head penetration safe ends are short tube lengths of stainless steel on the external extension of the penetration tubes that facilitate field welding of the austenitic stainless steel BMI instrumentation tubing. The response to Audit Queston 208 should say "bottom head penetration safe ends" rather than "bottom head drain safe ends

Part C

The steam generator primary nozzle closure rings are fabricated of nickel alloy. The closure rings are attached to the nozzles to support nozzle dams installed during outages. The closure rings are not relied on to maintain primary pressure boundary integrity and are therefore not subject to inservice inspection requirements.

GALL Report Table IV.D1, line item D1-1 applies to stainless steel components and is therefore not appropriate for comparison. Of the GALL Report Table IV.D1 line items that apply to cracking of nickel alloy, all but two (D1-4 and D1-6) are associated with steam generator tube integrity. Line item D1-4 applies to primary pressure boundary components. Line item D1-6 applies to the steam generator primary side divider plate, which is not part of the primary pressure boundary. Although it is a different component as denoted by Note C in the LRA table line item, alignment of the closure rings to line item D1-6 provides the best comparison to the GALL aging management review results. Line item D1-6 lists only the Water Chemistry Program for primary water. Inservice inspection is not specified as a program since the component is not part of the primary pressure boundary.

INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3
LICENSE RENEWAL APPLICATION
SER Open Items

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

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

Therefore, the staff considers that these components are subject to an AMR in accordance with 10 CFR 54.21(a)(1).

The applicant should justify why the yard hose houses and chamber housings are not subject to an AMR.

Response for OI 2.3A.3.11-1:

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

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

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

During an audit, the staff reviewed program basis documents (for IP3) associated with the fire protection AMP. One of the basis documents states that 15 percent of the fire seals located in fire barriers are demonstrated to be operable by visual inspection on a frequency of 24 months. However, for those penetration seals that are inaccessible, the frequency of inspection is given as "not required." By letter dated April 29, 2008, the staff requested that the applicant justify the lack of visual inspections of inaccessible penetration seals. In its response, dated May 28, 2008, the applicant stated that penetration seals are inspected at least once every seven operating cycles. However, IP3 site surveillance procedure provides provisions for cases where a penetration seal may become inaccessible for periodic inspection as result of plant configuration changes (i.e., installation of new plant equipment, walls, barriers, or other obstacles). In such cases, the IP3 site procedure includes guidance for the cessation of periodic surveillance of such penetration seals, subject to preparation of a formal fire protection engineering evaluation justifying the discontinuance of periodic visual surveillance.

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

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

Response for OI 3.0.3.2.7-1:

There are no IP3 fire barrier penetration seals excluded from periodic inspection due to inaccessibility. Therefore, there are no corresponding engineering evaluations.

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

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

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

Further information is required regarding the apparent discrepancies, before this item may be closed.

Response for OI 3.3-1:

LRA Table 3.3.2-2-IP2 is correct for titanium heat exchanger shell externally exposed to condensation with no aging effect and no AMP. LRA Table 3.3.2-9-IP2 is corrected as shown below to be consistent with Table 3.3.2-2-IP2. (underline – added, strikethrough – deleted)

In the second part of the Open Item the staff noted a difference between Tables 3.3.2-14-IP2 and 3.3.2-2-IP2 in that cracking was not identified as an aging effect for titanium heat exchanger tubes exposed to raw water (internal) in Table 3.3.2-14-IP2. The reason for this difference is that the titanium tubes in Table 3.3.2-14-IP2 for the emergency diesel generator are ASTM SB-338 Grade 2 titanium. As specified in the EPRI Mechanical Tools and the Metals Handbook, Ninth Edition, Volume 13, grades 1, 2, 7, 11, and 12 of titanium and its alloys are virtually immune to SCC except in a few specific environments (such as anhydrous methanol/halide solutions, red fuming nitric acid (HNO3), and liquid cadmium). Since these tubes are exposed to raw water cracking was not identified as an aging effect requiring management in Table 3.3.2-14-IP2. However in Table 3.3.2-2-IP2, the grade of titanium installed in the service water system is unknown so it was conservatively assumed that the material was not grades 1, 2, 7, 11 or 12 and cracking was identified as an aging effect requiring management.

Table 3.3.2-9-IP2: Containment Cooling and Filtration

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Heat exchanger (header)	Pressure boundary	Titanium	Condensation (ext)	~~Loss of material~~ None	~~Periodic Surveillance and Preventive Maintenance~~ None	--	--	F

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

Item 3.5.1-40 of LRA Table 3.5.1 addresses building concrete at locations of expansion and grouted anchors for the aging effect of reduction in concrete anchor capacity due to local concrete degradation/service-induced cracking or other concrete aging mechanisms. The GALL Report recommends the Structures Monitoring Program (SMP) for monitoring this concrete component for the stated aging effect. The staff finds that the applicant has appropriately credited the SMP for Groups B2 through B5 component supports and surrounding concrete consistent with the GALL Report. However, for the Group B1 (ASME Class 1, 2, 3 & MC) supports, the applicant's reference to "IP concrete anchors and surrounding concrete" implies that the applicant is crediting the ISI-IWF AMP for both the supports and surrounding concrete.

The staff finds that, while ISI-IWF is appropriate for the Group B1 component supports themselves, ISI-IWF is not specifically applicable for concrete surrounding the anchors for these supports, because the code support boundary definition which extends to the surface of the building but does not include the building structure. Therefore, the applicant should indicate which AMP it will use to manage the effects of aging for the concrete surrounding the B1 supports.

Response for OI 3.5-3:

As indicated in the discussion column for Item 3.5.1-40 of LRA Table 3.5.1, the applicable aging management program for concrete surrounding concrete anchors is the Structures Monitoring Program. The evaluation provided in LRA section 3.5.2.2.2.6 (1) is clarified to read as follows.

Concrete surrounding IPEC concrete anchors is included in the Structures Monitoring Program (Groups B1 through B5).

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

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

Response for OI 4.3-1:

The actual number of IP3 plant heatups and plant cooldowns through March 31, 2006 (including the period from 1995 to March 31, 2006) was determined to be 55. The 60 year projection of this value results in an estimate of 109 plant heatups and 109 plant cooldowns. This information was previously provided in response to audit item 14 in license renewal application Amendment 3 (NL-08-057) dated March 24, 2008.

Clarification for Table 4.3-10: Cumulative Usage Factors for the IP3 Steam Generators

Transposition errors of CUF values were identified in the application that resulted in the LRA requiring revision as described below. (underline – added, strikethrough – deleted)

Table 4.3-10
Cumulative Usage Factors for the IP3 Steam Generators

Location	CUF
Primary Side	
Divider plate	0.789
Tubesheet/shell junction	0.416
Tube/tubesheet weld	0.082
Tubes	0.161
Secondary Side	
Main feedwater nozzle	1.00
Secondary manway stud[1]	0.920
Steam nozzle	0.023
Steam nozzle support ring	~~0.894~~ 0.208
Steam nozzle insert	~~0.208~~ 0.894

ATTACHMENT 2 TO NL-09-018

IPEC Commitment List, Revision 7

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 & 3
DOCKET NOS. 50-247 AND 50-286

List of Regulatory Commitments

Rev. 7

The following table identifies those actions committed to by Entergy in this document.

Changes are shown as strikethroughs for ~~deletions~~ and underlines for additions.

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
1	Enhance the Aboveground Steel Tanks Program for IP2 and IP3 to perform thickness measurements of the bottom surfaces of the condensate storage tanks, city water tank, and fire water tanks once during the first ten years of the period of extended operation. Enhance the Aboveground Steel Tanks Program for IP2 and IP3 to require trending of thickness measurements when material loss is detected.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.1 A.3.1.1 B.1.1
2	Enhance the Bolting Integrity Program for IP2 and IP3 to clarify that actual yield strength is used in selecting materials for low susceptibility to SCC and clarify the prohibition on use of lubricants containing MoS_2 for bolting. The Bolting Integrity Program manages loss of preload and loss of material for all external bolting.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.2 A.3.1.2 B.1.2 Audit Items 201, 241, 270
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.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.5 A.3.1.5 B.1.6 Audit Item 173

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
4	Enhance the Diesel Fuel Monitoring Program to include cleaning and inspection of the IP2 GT-1 gas turbine fuel oil storage tanks, IP2 and IP3 EDG fuel oil day tanks, IP2 SBO/Appendix R diesel generator fuel oil day tank, and IP3 Appendix R fuel oil storage tank and day tank once every ten years. Enhance the Diesel Fuel Monitoring Program to include quarterly sampling and analysis of the IP2 SBO/Appendix R diesel generator fuel oil day tank, IP2 security diesel fuel oil storage tank, IP2 security diesel fuel oil day tank, and IP3 Appendix R fuel oil storage tank. Particulates, water and sediment checks will be performed on the samples. Filterable solids acceptance criterion will be less than or equal to 10mg/l. Water and sediment acceptance criterion will be less than or equal to 0.05%. Enhance the Diesel Fuel Monitoring Program to include thickness measurement of the bottom of the following tanks once every ten years. IP2: EDG fuel oil storage tanks, EDG fuel oil day tanks, SBO/Appendix R diesel generator fuel oil day tank, GT-1 gas turbine fuel oil storage tanks, and diesel fire pump fuel oil storage tank; IP3: EDG fuel oil day tanks, EDG fuel oil storage tanks, Appendix R fuel oil storage tank, and diesel fire pump fuel oil storage tank. Enhance the Diesel Fuel Monitoring Program to change the analysis for water and particulates to a quarterly frequency for the following tanks. IP2: GT-1 gas turbine fuel oil storage tanks and diesel fire pump fuel oil storage tank; IP3: Appendix R fuel oil day tank and diesel fire pump fuel oil storage tank. Enhance the Diesel Fuel Monitoring Program to specify acceptance criteria for thickness measurements of the fuel oil storage tanks within the scope of the program. Enhance the Diesel Fuel Monitoring Program to direct samples be taken and include direction to remove water when detected.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-057	A.2.1.8 A.3.1.8 B.1.9 Audit items 128, 129, 132, 491, 492, 510

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	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: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.10 A.3.1.10 B.1.11
6	Enhance the Fatigue Monitoring Program for IP2 to monitor steady state cycles and feedwater cycles or perform an evaluation to determine monitoring is not required. Review the number of allowed events and resolve discrepancies between reference documents and monitoring procedures. Enhance the Fatigue Monitoring Program for IP3 to include all the transients identified. Assure all fatigue analysis transients are included with the lowest limiting numbers. Update the number of design transients accumulated to date.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.11 A.3.1.11 B.1.12, Audit Item 164

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
7	Enhance the Fire Protection Program to inspect external surfaces of the IP3 RCP oil collection systems for loss of material each refueling cycle. Enhance the Fire Protection Program to explicitly state that the IP2 and IP3 diesel fire pump engine sub-systems (including the fuel supply line) shall be observed while the pump is running. Acceptance criteria will be revised to verify that the diesel engine does not exhibit signs of degradation while running; such as fuel oil, lube oil, coolant, or exhaust gas leakage. Enhance the Fire Protection Program to specify that the IP2 and IP3 diesel fire pump engine carbon steel exhaust components are inspected for evidence of corrosion and cracking at least once each operating cycle. Enhance the Fire Protection Program for IP3 to visually inspect the cable spreading room, 480V switchgear room, and EDG room CO_2 fire suppression system for signs of degradation, such as corrosion and mechanical damage at least once every six months.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.12 A.3.1.12 B.1.13

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
8	Enhance the Fire Water Program to include inspection of IP2 and IP3 hose reels for evidence of corrosion. Acceptance criteria will be revised to verify no unacceptable signs of degradation. Enhance the Fire Water Program to replace all or test a sample of IP2 and IP3 sprinkler heads required for 10 CFR 50.48 using guidance of NFPA 25 (2002 edition), Section 5.3.1.1.1 before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner. Enhance the Fire Water Program to perform wall thickness evaluations 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: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-014	A.2.1.13 A.3.1.13 B.1.14 Audit Items 105, 106

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
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: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.15 A.3.1.15 B.1.16

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
10	Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to include the following heat exchangers in the scope of the program. • Safety injection pump lube oil heat exchangers • RHR heat exchangers • RHR pump seal coolers • Non-regenerative heat exchangers • Charging pump seal water heat exchangers • Charging pump fluid drive coolers • Charging pump crankcase oil coolers • Spent fuel pit heat exchangers • Secondary system steam generator sample coolers • Waste gas compressor heat exchangers • SBO/Appendix R diesel jacket water 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 acceptance criteria for heat exchangers visually inspected to include no ~~unacceptable signs of degradation~~ <u>indication of tube erosion, vibration wear, corrosion, pitting, fouling, or scaling</u>.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 <u>NL-09-018</u>	A.2.1.16 A.3.1.16 B.1.17, Audit Item 52

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
11	Enhance the ISI Program for IP2 and IP3 to provide periodic visual inspections to confirm the absence of aging effects for lubrite sliding supports used in the steam generator and reactor coolant pump support systems.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.17 A.3.1.17 B.1.18 Audit item 59
12	Enhance the Masonry Wall Program for IP2 and IP3 to specify that the IP1 intake structure is included in the program.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.18 A.3.1.18 B.1.19
13	Enhance the Metal-Enclosed Bus Inspection Program to add IP2 480V bus associated with substation A to the scope of bus inspected. 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: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-057	A.2.1.19 A.3.1.19 B.1.20 Audit Items 124, 133, 519

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
14	Implement the Non-EQ Bolted Cable Connections Program for IP2 and IP3 as described in LRA Section B.1.22.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.21 A.3.1.21 B.1.22
15	Implement the Non-EQ Inaccessible Medium-Voltage Cable Program for IP2 and IP3 as described in LRA Section B.1.23. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E3, Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.22 A.3.1.22 B.1.23 Audit item 173
16	Implement the Non-EQ Instrumentation Circuits Test Review Program for IP2 and IP3 as described in LRA Section B.1.24. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E2, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.23 A.3.1.23 B.1.24 Audit item 173
17	Implement the Non-EQ Insulated Cables and Connections Program for IP2 and IP3 as described in LRA Section B.1.25. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E1, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.24 A.3.1.24 B.1.25 Audit item 173

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
18	Enhance the Oil Analysis Program for IP2 to sample and analyze lubricating oil used in the SBO/Appendix R diesel generator consistent with 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: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.25 A.3.1.25 B.1.26
19	Implement the One-Time Inspection Program for IP2 and IP3 as described in LRA Section B.1.27. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M32, One-Time Inspection.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.26 A.3.1.26 B.1.27 Audit item 173
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: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.27 A.3.1.27 B.1.28 Audit item 173
21	Enhance the Periodic Surveillance and Preventive Maintenance Program for IP2 and IP3 as necessary to assure that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.28 A.3.1.28 B.1.29

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
22	Enhance the Reactor Vessel Surveillance Program for IP2 and IP3 revising the specimen capsule withdrawal schedules to draw and test a standby capsule to cover the peak reactor vessel fluence expected through the end of the period of extended operation. Enhance the Reactor Vessel Surveillance Program for IP2 and IP3 to require that tested and untested specimens from all capsules pulled from the reactor vessel are maintained in storage.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.31 A.3.1.31 B.1.32
23	Implement the Selective Leaching Program for IP2 and IP3 as described in LRA Section B.1.33. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M33 Selective Leaching of Materials.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.32 A.3.1.32 B.1.33 Audit item 173
24	Enhance the Steam Generator Integrity Program for IP2 and IP3 to require that the results of the condition monitoring assessment are compared to the operational assessment performed for the prior operating cycle with differences evaluated.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.34 A.3.1.34 B.1.35
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)	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-057	A.2.1.35 A.3.1.35 B.1.36 Audit items 86, 87, 88, 417

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	• nuclear service building (IP1) • primary water storage tank foundation (IP3) • refueling water storage tank foundation (IP3) • security access and office building (IP3) • service water pipe chase (IP2/3) • service water valve pit (IP3) • superheater stack • transformer/switchyard support structures (IP2) • waste holdup tank pits (IP2/3) Enhance the Structures Monitoring Program for IP2 and IP3 to clarify that in addition to structural steel and concrete, the following commodities (including their anchorages) are inspected for each structure as applicable. • cable trays and supports • concrete portion of reactor vessel supports • conduits and supports • cranes, rails and girders • equipment pads and foundations • fire proofing (pyrocrete) • HVAC duct supports • jib cranes • manholes and duct banks • manways, hatches and hatch covers • monorails • new fuel storage racks • sumps, sump screens, strainers and flow barriers Enhance the Structures Monitoring Program for IP2 and IP3 to inspect inaccessible concrete areas that are exposed by excavation for any reason. IP2 and IP3 will also inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring. 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			

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	identify loss of material.			
	Enhance the Structures Monitoring Program for IP2 and IP3 to perform an engineering evaluation of groundwater samples to assess aggressiveness of groundwater to concrete on a periodic basis (at least once every five years). IPEC will obtain samples from at least 5 wells that are representative of the ground water surrounding below-grade site structures and perform an engineering evaluation of the results from those samples for sulfates, pH and chlorides. Additionally, to assess potential indications of spent fuel pool leakage, IPEC will sample for tritium in groundwater wells in close proximity to the IP2 spent fuel pool at least once every 3 months.		NL-08-127	Audit Item 360
	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.			Audit Item 358
26	Implement the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.37. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.36 A.3.1.36 B.1.37 Audit item 173
27	Implement the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.38. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M13, Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.37 A.3.1.37 B.1.38 Audit item 173

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
28	Enhance the Water Chemistry Control – Closed Cooling Water Program to maintain water chemistry of the IP2 SBO/Appendix R diesel generator cooling system per EPRI guidelines. Enhance the Water Chemistry Control – Closed Cooling Water Program to maintain the IP2 and IP3 security generator and fire protection diesel cooling water pH and glycol within limits specified by EPRI guidelines.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-08-057	A.2.1.39 A.3.1.39 B.1.40 Audit item 509
29	Enhance the Water Chemistry Control – Primary and Secondary Program for IP2 to test sulfates monthly in the RWST with a limit of <150 ppb.	IP2: September 28, 2013	NL-07-039	A.2.1.40 B.1.41
30	For aging management of the reactor vessel internals, IPEC will (1) participate in the industry programs for investigating and managing aging effects 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: September 28, 2011 IP3: December 12, 2013	NL-07-039	A.2.1.41 A.3.1.41
31	Additional P-T curves will be submitted as required per 10 CFR 50, Appendix G prior to the period of extended operation as part of the Reactor Vessel Surveillance Program.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.2.1.2 A.3.2.1.2 4.2.3
32	As required by 10 CFR 50.61(b)(4), IP3 will submit a plant-specific safety analysis for plate B2803-3 to the NRC three years prior to reaching the RT_{PTS} screening criterion. Alternatively, the site may choose to implement the revised PTS rule when approved.	IP3: December 12, 2015	NL-07-039 NL-08-127	A.3.2.1.4 4.2.5

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
33	At least 2 years prior to entering the period of extended operation, for the locations identified in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3), under the Fatigue Monitoring Program, IP2 and IP3 will implement one or more of the following: (1) Consistent with the Fatigue Monitoring Program, Detection of Aging Effects, update the fatigue usage calculations using refined fatigue analyses to determine valid CUFs less than 1.0 when accounting for the effects of reactor water environment. This includes applying the appropriate Fen factors to valid CUFs determined in accordance with one of the following: 1. For locations in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3), with existing fatigue analysis valid for the period of extended operation, use the existing CUF. 2. Additional plant-specific locations with a valid CUF may be evaluated. In particular, the pressurizer lower shell will be reviewed to ensure the surge nozzle remains the limiting component. 3. Representative CUF values from other plants, adjusted to or enveloping the IPEC plant specific external loads may be used if demonstrated applicable to IPEC. 4. An analysis using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case) may be performed to determine a valid CUF. (2) Consistent with the Fatigue Monitoring Program, Corrective Actions, repair or replace the affected locations before exceeding a CUF of 1.0.	IP2: September 28, 2011 IP3: December 12, 2013	NL-07-039 NL-07-153 NL-08-021	A.2.2.2.3 A.3.2.2.3 4.3.3 Audit item 146
34	IP2 SBO / Appendix R diesel generator will be installed and operational by April 30, 2008. This committed change to the facility meets the requirements of 10 CFR 50.59(c)(1) and, therefore, a license amendment pursuant to 10 CFR 50.90 is not required.	April 30, 2008 Complete	NL-07-078 NL-08-074	2.1.1.3.5

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
35	Perform a one-time inspection of representative sample area of IP2 containment liner affected by the 1973 event behind the insulation, prior to entering the extended period of 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 extended period of operation, to assure liner degradation is not occurring in this area. <u>Any degradation will be evaluated for updating of the containment liner analyses as needed.</u>	IP2: September 28, 2013 IP3: December 12, 2015	NL-08-127 <u>NL-09-018</u>	Audit Item 27
36	Perform a one-time Inspection and evaluation of a sample of potentially affected IP2 refueling cavity concrete prior to the period of extended operation. The sample will be obtained by core boring the refueling cavity wall in an area that is susceptible to exposure to borated water leakage. The inspection will include an assessment of embedded reinforcing steel.	IP2: September 28, 2013	NL-08-127	Audit Item 359
37	Enhance the Containment Inservice Inspection (CII-IWL) Program to include inspections of the containment using enhanced characterization of degradation (i.e., quantifying the dimensions of noted indications through the use of optical aids) during the period of extended operation. The enhancement includes obtaining critical dimensional data of degradation where possible through direct measurement or the use of scaling technologies for photographs, and the use of consistent vantage points for visual inspections.	IP2: September 28, 2013 IP3: December 12, 2015	NL-08-127	Audit Item 361
38	For Reactor Vessel Fluence, should future core loading patterns invalidate the basis for the projected values of RTpts or C_VUSE, updated calculations will be provided to the NRC.	IP2: September 28, 2013 IP3: December 12, 2015	NL-08-143	4.2.1