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NL-15-092

August 18, 2015

U.S. Nuclear Regulatory Commission
Document Control Desk
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Rockville, MD 20852-2738

SUBJECT: Reply to Request for Additional Information for the Review of the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application, SET 2015-01 (TAC Nos. MD5407 and MD5408)
Docket Nos. 50-247 and 50-286
License Nos. DPR-26 and DPR-64

REFERENCE: NRC letter, "Request for Additional Information for the Review of the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application, SET 2015-01 (TAC Nos. MD5407 and MD5408)" dated May 4, 2015.

Dear Sir or Madam:

Entergy Nuclear Operations, Inc. (Entergy) is providing, in Attachment 1, the additional information requested in the referenced letter pertaining to NRC review of the License Renewal Application (LRA) for Indian Point 2 and Indian Point 3.

The responses provided in Attachment 1 contain new regulatory commitments that are identified on the list of regulatory commitments provided in Attachment 3. Changes to the LRA sections that are as a result of the responses are provided in Attachment 2. On July 29, 2015, Entergy requested and was subsequently granted a three-week extension to submit the subject response. A new due date of August 24, 2015 was agreed upon.

If you have any questions, or require additional information, please contact Mr. Robert Walpole at 914-254-6710.

A128
NRR

I declare under penalty of perjury that the foregoing is true and correct. Executed on Aug 18, 2015.

Sincerely,

FRD/rl

Attachments:

1. Reply to NRC Request for Additional Information Regarding the License Renewal Application
2. License Renewal Application Changes Due To Responses To Requests For Information
3. License Renewal Application IPEC List of Regulatory Commitments Revision 27

cc: Mr. Daniel H. Dorman, Regional Administrator, NRC Region I
Mr. Sherwin E. Turk, NRC Office of General Counsel, Special Counsel
Mr. Dave Wrona, NRC Branch Chief, Engineering Review Branch I
Mr. Douglas Pickett, NRR Senior Project Manager
Ms. Bridget Frymire, New York State Department of Public Service
NRC Resident Inspector's Office
Mr. John B. Rhodes, President and CEO NYSERDA

ATTACHMENT 1 TO NL-15-092

REPLY TO NRC REQUEST FOR ADDITIONAL INFORMATION

REGARDING THE

LICENSE RENEWAL APPLICATION

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

REQUEST FOR ADDITIONAL INFORMATION, SET 2015-01 RELATED TO INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL APPLICATION

RAI 3.0.3-3

Background:

Entergy Nuclear Operations Inc. (Entergy), in a letter dated December 16, 2014, responds to request for additional information (RAI) 3.0.3-1 and addresses the issues contained in LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation." Regarding LR-ISG-2012-02, Section A, "Recurring Internal Corrosion," the response states that reviews of past plant-specific operating experience identified recurring internal corrosion due to general, pitting, and crevice corrosion that resulted in through-wall leaks at least once in each of three refueling cycles in the last 10 years for both units. For the service water system, the response states that minor corrosion issues still occur, but these "do not compromise the intended functions of the service water system." In discussing through-wall leaks for cement-line carbon steel piping or stainless steel and copper alloy piping, the response also states that "based on operating experience, such leaks have no impact on system performance and have not threatened the structural integrity of the piping or the safety function of nearby equipment."

Issue:

During its review, the staff identified plant-specific operating experience which appears to indicate that corrosion issues did compromise the intended function of the service water system. In this regard, Licensee Event Report (LER) 286/2011-003, "Technical Specification Required Shutdown and a Safety System Functional Failure for a Leaking Service Water Pipe Causing Flooding in the SW [service water] Valve Pit Preventing Access for Accident Mitigation," dated April 25, 2011, states: "After further evaluation, it was concluded there was a loss of safety function," and "It was concluded that this condition was a safety system functional failure." Based on the 2011 LER, the statement in the December 2014 response, regarding "no impact of system performance," appears to be unfounded.

In addition, LER 286/2002-001, "Operation in a Condition Prohibited by Technical Specifications Due to an Inoperable Service Water Pipe Caused by a Leak that Exceeded the Allowable Outage Time," dated July 5, 2002, states, "Engineering evaluation of data collected concluded that the leaking pipe did not provide sufficient structural integrity for the piping to meet code allowables for pipe thinning and through wall leaks and therefore was inoperable." Although this LER is beyond the 10-year operating experience review window conducted for RAI 3.0.3-1, the staff notes that this operating experience was not included in the license renewal application (LRA) in the discussion for the operating experience of the Service Water Integrity Program. Also, the staff notes that by letter dated June 5, 2008, Entergy responded to RAI AUX-1, which relates to the staff's questions on the operating experience summaries for several aging management programs (AMPs), including the Service Water Integrity Program. For "IP3 service water degradation," the 2008 response discusses the detection of loss of material during inspections from 2001 to 2004 and states that "these conditions did not result in a loss of system intended function. Engineering review of external corrosion and a pinhole leak did not

result in any operability concerns." Based on LER 286/2002-001, the significance of past operating experience, regarding structural integrity and operability, may not have been adequately characterized by the statements made in the 2008 RAI response.

Request:

Explain and reconcile the information related to loss of safety function contained in the December 2014 response to RAI 3.0.3–1 and LER 286/2011-003. In addition, explain and reconcile the information related to the structural integrity and operability in the 2008 response to RAI AUX-1 and LER 286/2002-001.

Response to RAI 3.0.3-3

A. Information Contained in December 2014 Response to RAI 3.0.3–1 and LER 286/2011-003

By way of background, the Staff issued RAI 3.0.3-1 on April 1, 2014. That RAI requested, in pertinent part, that Entergy provide details on how the updated guidance of LR-ISG-2012-02 has been accounted for in the IPEC license renewal AMPs and AMR items. In its December 16, 2014 response to RAI 3.0.3-1, Entergy stated that it reviewed (1) the updated guidance of LR-ISG-2012-02 Section A "Recurring Internal Corrosion" with respect to the IPEC LRA, and (2) the past 10 years of plant-specific operating experience for IP2 and IP3 to identify "recurring internal corrosion" as defined in LR-ISG-2012-02, Section A. With respect to the service water systems, the December 16, 2014 RAI response states, in relevant part:

> The Service Water Integrity Program implements the guidelines of NRC Generic Letter 89-13, including routine inspection and maintenance to ensure that degradation due to corrosion, erosion and biofouling cannot prevent safety-related systems cooled by service water from satisfactorily performing their intended functions. As concluded in NUREG-1930, the effects of aging are adequately managed by the Service Water Integrity Program so that the intended functions are maintained. However, minor corrosion issues that do not compromise the intended functions of the service water system still occur. Carbon steel service water system piping is internally lined with cement, which is very effective in protecting the carbon steel piping. Where discontinuities in the cement lining (such as at piping segment welds) allow the service water to directly contact the carbon steel, corrosion can occur. This corrosion can result in a through-wall leak. Stainless steel and copper alloy piping components also develop through-wall leaks due to localized pitting corrosion. Based on operating experience, such leaks have had no impact on system performance and have not threatened the structural integrity of the piping or the safety function of nearby equipment.

RAI 3.0.3–3 appears to be based on the notion that the event reported in LER 286/2011-003 resulted from recurring internal corrosion issues that compromised the intended function of the service water system, in apparent contradiction of Entergy's statement above that "such leaks have had no impact on system performance." LER 286/2011-003 reported a leak from Unit 3 service water line 1222 downstream of an isolation valve. That leak did not result from the aging effect of recurring internal corrosion or the "minor corrosion issues" discussed in Entergy's December 16, 2014 RAI response. Although the event reported in LER 286/2011-003 involved

a through-wall leak that resulted in a loss of safety function, the root cause of the leak was a work control issue. Specifically, LER 286/2011-003 describes the cause of the event as follows:

> The direct cause of the leak was a 3/4 inch hole in the 10 inch Conventional Essential SW header line #1222 downstream of valve SWN-6 due to a through wall leak. The likely cause of the through wall hole was corrosion due to inadequate coating of the interior of the carbon steel pipe during a previous pipe repair. <u>The root cause was an inadequate installation plan and repair of a flaw identified in 1992</u>. A review of work history for this portion of SW pipe identified a Work Order for line #1222 in the location of the leak that removed a temporary repair patch at a weld on the downstream flange of valve SWN-6 and installed a permanent repair. The method of repair chosen was a weld insert requiring a portion of the pipe to be cut out and a new piece installed. A WaterPlug epoxy coating was used to coat the inside of the pipe where the concrete lining was removed for the repair. The weld insert method did not take into account the difficulty of coating the interior of the carbon steel pipe once the cement lining was removed. The WO that was planned for the repair in 1992 could not be properly implemented and resulted in inadequately coated carbon steel piping. Given the limited access to the pipe internals and the amount of pipe that would need to be coated after welding, the repair method should have been a replacement of the affected section of pipe.

The root cause determination was performed under the Unit 3 corrective action program. As noted above, the root cause of the failure and loss of safety function described in LER 286/2011-003 was determined to be "an inadequate installation plan and repair of a flaw identified in 1992." It was not due to the effects of aging. Entergy reviewed LER 286/2011-003 in preparing its response to RAI 3.0.3-1, and judged the information contained in the LER not relevant to the RAI. That is, Entergy did not consider the service water line leak described in LER 286/2011-003 an example of recurring internal corrosion, as defined in LR-ISG-2012-02. Accordingly, Entergy concludes that there is no inconsistency between statements in the December 2014 response to RAI 3.0.3-1 and the information contained in LER 286/2011-003.

B. <u>Information Contained in June 2008 Response to RAI AUX–1 and LER 286/2002-001</u>

LER 286/2002-001 does not contain any statements that are inconsistent with the response to RAI AUX-1, or raise concerns about the adequacy of operating experience or corrective actions considered under the Service Water Integrity Program (SWIP). As discussed in the LER, on June 5, 2002, Entergy personnel discovered a small leak in an 18-inch cement-lined carbon steel service water header (line 408) while performing routine rounds. Engineering personnel inspected the pipe and confirmed a leak in a weld to a tee connection. The condition was entered into the IP3 corrective action program. Entergy performed NDE on the weld as well as radiographic and ultrasonic testing to characterize the extent of degradation. Based on their review of the data collected, engineering personnel concluded that the degraded condition did not provide sufficient structural integrity, and results of a pipe stress analysis could not support operability with the existing flaw. Entergy repaired the affected service water piping in accordance with ASME Code Section XI requirements and conducted post-repair testing before declaring the pipe operable.

As explained in LER 286/2002-001, Entergy determined the cause of the condition to be long-term corrosion of the carbon steel weld metal at the unprotected gap at the weld seam on a butt weld of the pipe due to exposure of the carbon steel to brackish service water with oxygen. The exposure occurred as a result of an inadequate cement lining at the pipe weld juncture—i.e., a welding-related defect that occurred at the time of plant construction.

LER 286/2002-001 states there was no documented evidence of a previous piping repair or replacement in this area, and that this leak was the first leak in this location. Importantly, the LER further states that "[a] review of the NDE for the leaking piping (line number 408) did not identify any new degradation mechanism that is not already considered by the SW corrosion monitoring program required by Generic Letter 89-13", and that "[p]revious leaks on code class SW piping were found to be operable." It also states that the weld appears to be unique, in that a similar tee weld on line 409 was found satisfactory based on testing and inspections.

As documented in NRC Inspection Report No. 50-286/02-04, dated July 30, 2002, NRC inspectors confirmed the Entergy findings discussed above:

> The inspectors reviewed the root cause evaluation that was issued on July 10, 2002, for this specific pipe leak. The report concluded that the weld was defective from original plant construction and was aggravated by long-term crevice corrosion. The inspectors also reviewed with cognizant engineering personnel procedure TSP-048, "IP3 SWS Corrosion Monitoring Program Implementing Procedure," which implements service water corrosion-monitoring under the licensee's Generic Letter 89-13 program. This specific weld was not previously included in past inspection samples; however, the root cause evaluation did not identify any new degradation mechanism that was not already considered by the monitoring program.

In summary, although the line 408 service water header leak reported in LER 286/2002-001 involved internal corrosion of carbon steel, the root cause evaluation determined the root cause to be a unique weld defect that had existed since plant construction. The root cause evaluation did not identify any new degradation mechanism that is not already considered by the SWIP, which is consistent with GALL AMP XI.M20 and implements the recommendations of GL 89-13.

RAI 3.0.3-4

Background:

Entergy letter dated December 16, 2014, responds to RAI 3.0.3-1 and addresses the issues contained in LR-ISG-2012-02. Regarding LR-ISG-2012-02, Section A, "Recurring Internal Corrosion," the response states that reviews of past plant-specific operating experience identified at least one through-wall leak in each of three refueling cycles in the last 10 years for both units due to general, pitting, and crevice corrosion. For the service water system, the response states that minor corrosion issues still occur, but these "do not compromise the intended functions of the service water system." In discussing through-wall leaks for cement-line carbon steel piping or stainless steel and copper alloy piping, the response also states that "based on operating experience, such leaks have no impact on system performance and have not threatened the structural integrity of the piping or the safety function of nearby equipment." The response subsequently includes an enhancement to the Service Water Integrity Program "to incorporate the actions used to manage the minor corrosion issues in the service water system." The enhancement, to be implemented by 2019, consists of revising procedures to evaluate through-wall leaks under the corrective action program and to inspect portions of the buried service water by robotic crawler or manual crawl-through.

Recent LERs (286/2014–002, 247/2013–004, and 286/2011–003) discuss additional leaks in the service water system piping. The first LER (286/2014–002) states that Procedure 3-PTR185B (Primary Auxiliary Building SW Piping and Valve Flush) was developed specifically to address recurring problems with leaks in stagnant vent and drain piping and that the procedure is the "main line of defense for preventing future leaks in small bore carbon steel piping socket welds." The staff notes that the initial Service Water Integrity Program previously included periodic flushing of infrequently used loops to manage loss of material in service water components. The second LER (247/2013–004) discusses replacement of certain portions of Series 300 stainless steel piping (which replaced the original carbon steel piping) in the service water system with highly corrosion resistant material. The replacement plan was developed after deficiencies were identified in 2008. The third LER (286/2011–003) discusses the loss of safety function for a portion of the service water system and states that the Generic Letter (GL) 89-13 program (the basis for the Service Water Integrity Program) will be revised to prioritize inspection frequencies of service water welds.

The significance of the degradation identified in the third LER (286/2011–003) prompted the staff to review the responses to GL 89–13 for IP2 and IP3. The staff noted a difference between the current licensing basis for the two responses. The February 2, 1990, response for IP2 discussed an in-place "QA radiographic program" that randomly inspects 10 percent of the service water piping welds annually, whereas the September 9, 1992, response for IP3 includes ultrasonic inspections of non-cement lined portions and visual inspections using a robotic crawler with a high resolution camera. The staff notes that a 1991 status update for IP2 on various Action Items for GL 89–13 states: "We have initiated an internal visual inspection program for underground service water piping. This program utilizes pipe crawling video equipment to inspect and record the condition of the cement-lined underground pipe."

Issue:

Given the enhancements to the Service Water Integrity Program proposed in the December 16, 2014 letter, the current details of the program implementation are unclear to the staff. Since the IP2 and IP3 responses to GL 89-13 both refer to using remote crawlers and one response specifically addresses underground service water piping, it is not clear to the staff how the current enhancement for internally inspecting buried service water piping (to be implemented prior to 2019) differs from the program that (based on the current licensing basis) was previously in place. In addition, regarding the other currently proposed enhancement to the Service Water Integrity Program (evaluating leakage under the corrective action program), the need for revised procedures to evaluate through-wall leaks under the corrective action program implies that leakage currently may not be evaluated under the corrective action program. In this regard, too, it is not clear to the staff how the proposed enhancement differs from the program that was previously in place, given that LRA Section B.0.3 states the "corrective action controls of the Entergy (10 CFR Part 50, Appendix B) Quality Assurance Program are applicable to all aging management programs and activities."

Based on the operating experience discussed in the above LERs, enhancements to the Service Water Integrity Program have been implemented beyond the version of the program that was evaluated by the staff in NUREG-1930, "Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3." For LER 286/2011-003, the program apparently did not adequately manage the effects of aging because an intended function of the system was not maintained consistent with the current licensing basis. SRP-LR Section A.1.2.3.10 states that a past failure would not necessarily invalidate an aging management program because the feedback from operating experience should have resulted in appropriate program enhancements or new programs. In that regard, it is not clear to the staff what changes have been made to the program over the years as a result of past operating experiences or what changes have been made to the prior commitments for GL 89–13.

Request:

1) Provide a description and chronological history of any enhancements that have been made to the Service Water Integrity Program, from the version of the program reviewed by the staff as documented in NUREG–1930, as a result of Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3) site-specific operating experience. If no enhancements have been made, then discuss the meaning of the statement in LER 286/2011-003 regarding changes that will be made to the GL 89-13 program. In addition, clarify whether Procedure 3-PT-R185B was revised as a result of the extent of condition review discussed in LER 286/2014-002, and if it was not revised, discuss how the "recurring problems with leaks developing in stagnant vent and drain connection piping and valves" (identified in the extent of condition review) are being addressed.

2) Clarify whether (and if so, when) any changes have been made to previously docketed licensing commitments for the IP2 and IP3 responses to GL 89–13, and provide information as to whether (and if so, when) that the NRC has been informed of any changes.

3) For the two proposed enhancements in the response to RAI 3.0.3-1, clarify the differences between the new enhancement activities and the activities in the previously implemented program.

4) Provide the following details for the current Service Water Integrity Program:

    a) the amount and timing of any past (and if they are to be credited, any planned) service water system piping replacements;
    b) trend data from the past 10 years for the number of leaks caused by age-related degradation;
    c) the number and frequency of volumetric inspections being performed to both track known degradation locations and identify additional degradation locations;
    d) the type (internal or external), amount, and frequency of visual inspections being performed;
    e) the criteria used to determine locations for and adjustments to the number and frequency of volumetric and visual inspections, including any predictive methodology. In responding to Request No. 1 and Request No. 4, parts c, d, and e, state whether these actions will continue during the timely renewal period and period of extended operation; and revise the Service Water Integrity Program and corresponding Updated Final Safety Analysis Report supplement accordingly.

RAI 3.0.3-4, Request 1

Provide a description and chronological history of any enhancements that have been made to the Service Water Integrity Program, from the version of the program reviewed by the staff as documented in NUREG–1930, as a result of Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3) site-specific operating experience. If no enhancements have been made, then discuss the meaning of the statement in LER 286/2011-003 regarding changes that will be made to the GL 89-13 program. In addition, clarify whether Procedure 3-PT-R185B was revised as a result of the extent of condition review discussed in LER 286/2014-002, and if it was not revised, discuss how the "recurring problems with leaks developing in stagnant vent and drain connection piping and valves" (identified in the extent of condition review) are being addressed.

Response

An enhancement is typically a change to make an AMP consistent with the corresponding NUREG-1801 AMP. The NUREG-1801, Section XI.M20, Open-Cycle Cooling Water System Program is based upon the IPEC commitments to GL 89-13. See NUREG-1930, Vol. 2 at 3-54 ("The Service Water Integrity Program implements the recommendations of GL 89-13 for managing the effects of aging on the service water (SW) system, through the period of extended operation."). Therefore, changes to the IPEC AMP to make the AMP consistent with the GL 89-13 commitments would be considered an enhancement. By necessity, however, licensees sometimes make changes to programs that are below the level of detail typically provided in a NUREG-1801 AMP description. Below is a chronological summary of the changes that Entergy has made to the Service Water Integrity Program governing procedure since NUREG-1930 was issued in November 2009.

July 2011

The procedure was revised to raise the priority for inspections of nonsafety-related service water piping in locations where a leak can cause flooding, and where this flooding can prevent operators from manually manipulating valves. The inspection frequency for such piping was changed to the same inspection frequency as that for safety-related service water piping. The change was made under the corrective action program in response to an event involving a leak in nonsafety-related service water piping (LER 286/2011-003). Even though nonsafety-related piping inspections were already in the program, additional piping was added and inspection frequencies were increased to match those of safety-related piping. This was the direct result of site-specific OE. This reinforces the Staff's conclusion in the 2009 SER (NUREG-1930, Vol. 2, at 3-57) that "the applicant has provided an acceptable basis for managing aging effects in the nonsafety-related service water system components consistent with the program elements in GALL AMP XI.M20."

As the Staff notes, the initial Service Water Integrity Program previously included periodic flushing of infrequently used loops to manage loss of material in service water components. See also NUREG-1930, Vol. 2, at 3-56 to 3-57. However, a section for piping vent and drain connection flushing was added to the program governing procedure. This section was added in response to a corrective action assigned under the corrective action program, when it was noted that Unit 2 did not have a procedure equivalent to the Unit 3 flushing procedure, 3PT-R185B. The flushing procedure at Unit 3 was for stagnant piping or piping with low flow velocities that is subject to MIC formation, silt build-up, and general corrosion and pitting corrosion. The Unit 3 procedures have been effective since being instituted in 2001. Therefore, the program was enhanced to add similar flushing procedures for IP2.

<u>February 2012</u>

The program procedure was revised in response to site-specific OE involving silt build-up in the SW pump bays. IPEC increased the sonar mapping frequency from once every two years to once every three months to monitor and map the accumulation of silt in the bays. The increased frequency accounts for impacts of adverse weather and external events that can cause rapid accumulation of silt in the bays. This change was not made to manage the effects of aging, but to better manage the effects of weather-related events that influence the rate of silt accumulation.

<u>October 2012</u>

The program was updated for administrative reasons and not due to any site-specific OE related to managing the effects of aging. No substantive changes to the program were made.

Procedure 3PT-R185B was not revised as a result of the event described in LER 286/2014-002. This procedure, developed in 2001, is a periodic surveillance procedure that is performed every two years to flush and inspect lines that may be susceptible to silt build-up. Flushing the lines minimizes the effect of stagnant conditions in the service water system. As noted above, the procedure has been effective in achieving that objective. The leak described in LER 286/2014-

002 was on a ¾" sample line, downstream of a component cooling water heat exchanger. The leakage was so small that it could not be quantified. Because the flaw was on a socket weld, it could not be characterized with NDE. Therefore, the affected sample line was conservatively declared inoperable, isolated, and replaced. It is rare, however, that the issues identified in these small lines result in operability issues.

As a result of the review of the issue identified in the LER, Entergy found no need to make changes to procedure 3-PT-RI85B. The flushing and inspections performed under procedure 3-PT-R185B have been effective at managing the effects of aging. As a result, small bore socket weld leaks in the SW systems at both IPEC units are typically pinhole-sized leaks that are structurally acceptable and do not challenge SW cooling system inventory or cause flooding concerns.

RAI 3.0.3-4, Request 2

Clarify whether (and if so, when) any changes have been made to previously docketed licensing commitments for the IP2 and IP3 responses to GL 89–13, and provide information as to whether (and if so, when) that the NRC has been informed of any changes.

Response

The Service Water Integrity Program includes IPEC activities that implement commitments made in response to NRC Generic Letter 89-13. Those program activities are subject to inspection during the formal NRC triennial heat sink performance inspection. In addition to inspecting the IPEC program during the triennial heat sink performance inspections, the NRC Staff reviewed the program during the license renewal aging management program audits in 2008. Changes to the program since its inception in response to GL 89-13 were reflected in the program documentation reviewed in 2008. As described in response to item (1) above, there have been improvements and enhancements to the program since 2008. Typically, changes to the program entail the addition of activities that were not required by commitments to GL 89-13. For example, following a leak in 1995, the program was modified to add valve inspections in addition to the piping inspections that were established to meet GL 89-13 commitments. The program change identified in response to item (1) to increase the number and frequency of inspections of nonsafety-related piping is another example of a change that exceeds what was required by GL 89-13 commitments. These program changes do not involve commitment changes and, therefore, do not need to be evaluated against the commitment management process criteria for reporting to the NRC. No program changes have been identified since 2008 that have constituted changes to GL 89-13 commitments.

RAI 3.0.3-4, Request 3

For the two proposed enhancements in the response to RAI 3.0.3-1, clarify the differences between the new enhancement activities and the activities in the previously implemented program.

Response

The activities in the proposed enhancements (i.e., revising procedures to evaluate through-wall leaks under the corrective action program and to inspect portions of the buried service water

piping by robotic crawler or manual crawl-through) are performed as part of the established Service Water Integrity Program. The intent of the enhancements is to explicitly identify these activities in the program procedures as commitments related to the renewed license. Therefore, there is no difference between the new enhancement activities and the activities in the established program.

RAI 3.0.3-4, Request 4a

Provide the following details for the current Service Water Integrity Program:

The amount and timing of any past (and if they are to be credited, any planned) service water system piping replacements;

Response

The following are the service water (SW) piping replacements completed at IPEC. Piping lengths for replaced piping are approximate. In some cases, these projects were multi-year projects and the most relevant date is listed.

Unit 2

- Main Boiler Feed Water Pump cooling water piping replacement (60 ft, 2010)
- Containment Fan Cooler Unit Outlet piping at SWN TCV-1103, -1104, -1105 (40 ft, 2010)
- Main Generator Hydrogen cooler vent and drain piping (120 ft, 2010)
- Zurn Strainer Blowdown piping (120 ft, 2010)
- Radiation Monitoring piping replacement (200 ft, 2014)

Unit 3

- Containment Fan Cooler Unit Outlet - Replace piping around TCV-1103 (15 ft, 2011)
- Main Generator Exciter Cooler inlet piping (60 ft, 2009)

Prior to the year 2009, various piping replacements and upgrades were performed at IPEC. Some of these projects were multi-year projects and were planned based on feedback from the corrective action program. These include the Unit 2 Emergency Diesel Generator supply piping (45 ft). On Unit 3, projects included Central Control Room Air Conditioning supply and return piping (100 ft), Main Generator Iso-Phase Cooler supply and return piping (100 ft), Containment Fan Cooler Unit supply relief line (150 ft), Zurn Strainer SW Blowdown piping (120 ft), Emergency Diesel Generator supply piping (15 ft), Main Generator Seal Oil skid supply and return piping (80 ft), Instrument Air Closed Cooling supply and return piping (150 ft), Main Generator H2 Cooler vent and drain piping (80 ft).

The replacements are corrective actions resulting from findings during program inspection activities or from small leaks identified during plant operation. Piping replacements are not credited as preventive actions in the Service Water Integrity Program, but may be directed as corrective actions.

In addition to piping replacements, a new strategy was recently engineered and approved for non-ISI code portions of the service water system. This involves wrapping external portions of

system piping with carbon fiber material in lieu of intrusive piping replacements. This strategy was developed as a corrective action to improve the system material condition.

RAI 3.0.3-4, Request 4b

Provide the following details for the current Service Water Integrity Program:

Trend data from the past 10 years for the number of leaks caused by age-related degradation;

Response

The numbers of SW leaks in ISI Class 3 (safety-related) carbon and stainless steel piping by year for both IPEC units combined are as follows.

IPEC Total ISI Class 3 Leaks	
2005	5
2006	4
2007	8
2008	7
2009	6
2010	6
2011	3
2012	1
2013	3
2014	1
2015*	2

* As of 6/30/15

The total numbers of leaks on all portions of the service water system that were deemed due to the effects of aging are as follows. Leaks in safety-related and nonsafety-related piping are included.

IPEC Total Leaks	
2005	5
2006	5
2007	8
2008	16#
2009	10
2010	16
2011	9
2012	7
2013	11
2014	2
2015	2

On Unit 2, there were 9 leaks in 2008 that were due to pitting on a section of stainless steel zurn strainer blowdown piping that was subsequently replaced.

RAI 3.0.3-4, Request 4c

Provide the following details for the current Service Water Integrity Program:

The number and frequency of volumetric inspections being performed to both track known degradation locations and identify additional degradation locations;

Response

The established Service Water Integrity Program targets susceptible locations for wall thickness inspections and conducts follow-up inspections for trending purposes of piping locations where corrosion has been previously identified.

The program provides a means to proactively detect and repair areas of concern, while also providing a means to schedule and perform future inspections/repairs. The Service Water Integrity Program inspects about 20-30 welds per unit prior to each outage (i.e., pre-outage) which includes both new inspection points as well as follow up exams of known areas of concern. Generally, new locations form the majority of the inspection points, and the follow up inspection points are a lesser portion. This is mainly because if areas of concern are found, wall thickness calculations are performed and repairs are planned based on the projected remaining life.

Since 1997, there have been over 600 weld examinations performed at both IPEC units, with greater than 90 percent of the examined welds meeting the applicable acceptance criteria. Those welds not meeting the established acceptance criteria are repaired during subsequent refueling outages.

RAI 3.0.3-4, Request 4d

Provide the following details for the current Service Water Integrity Program:

The type (internal or external), amount, and frequency of visual inspections being performed;

Response

At both IPEC units, exterior visual inspections of service water system piping are performed monthly by engineering personnel. Operations personnel also perform inspections as part of their normal watch routines. In addition, each time a SW system piping component or heat exchanger is opened for preventive or corrective maintenance, plant procedures require that Engineering perform an internal condition assessment. Program activities include interior visual inspections for condition assessment of sections of underground and buried piping via remote robotic crawlers fitted with video cameras.

When a portion of the system is routinely opened, or if preventative maintenance task requires opening the system, then an inspection is scheduled and performed. Engineering is contacted by the organization performing the work when the system is opened. Generally, in addition to

scheduled openings, when non-routine or unplanned openings of the system occur, the working organization also will contact engineering to perform an inspection.

External inspections of buried SW piping are implemented under the Buried Piping Program. The inspection locations, piping lengths inspected, and inspection frequencies are specified by that program and its implementing procedures.

For the large-bore buried SW headers where it is not possible to perform NDE at the weld locations, mechanical seals have been designed for weld locations to protect them from the brackish Hudson River water. These seals ensure that internal corrosion potential and related service water leaks from buried and underground piping are minimized. The seals have been installed at Unit 3 for both 24" service water headers and protect approximately 1500 ft. of buried pipe. Completion of mechanical seal installation at Unit 2 is pending.

RAI 3.0.3-4, Request 4e

Provide the following details for the current Service Water Integrity Program:

The criteria used to determine locations for and adjustments to the number and frequency of volumetric and visual inspections, including any predictive methodology.

Response

Examinations are performed on safety-related (Class A / Cat. I) portions of the SW piping (ISI Class A, Class 3/3A) as the first priority. Nonsafety-related piping is also examined on an as-needed basis as determined by trending of examination results. Applicable portions of nonsafety-related piping, the failure of which can cause damage to other safety systems/components due to flooding, are included in the program.

Volumetric examinations (radiography and ultrasonic testing) of large bore service water pipe are also conducted. Between outages, the Program Owner, in conjunction with the SW System Engineer, selects the areas to be inspected. Historical data and piping configuration are used in selecting future inspection points. The inspection results are compared to results from previous inspections. The program also includes consideration of follow-ups to previous repairs and condition assessments from preventive maintenance activities where components are opened.

Inspections of nonsafety-related SWS piping welds are performed via NDE methods using the same programmatic procedures as safety-related SWS piping welds, with the major difference being that the majority of inspections are conducted on safety-related piping welds. As an example, for the 2R18 outage in March/April 2008, approximately 10% of the scheduled volumetric weld examinations (RT & UT) were conducted on nonsafety-related SWS piping welds, and approximately 25% of the scheduled visual inspections were conducted on nonsafety-related SWS piping. The visual inspections were made using a remote video robotic crawler.

Scope expansion for indications found by program inspections of nonsafety-related piping is based on engineering analysis, judgment and program experience. The factors that are considered include piping location, severity of use, piping materials, previous inspection results, and repair history.

In responding to Request No. 1 and Request No. 4, parts c, d, and e, state whether these actions will continue during the timely renewal period and period of extended operation; and revise the Service Water Integrity Program and corresponding Updated Final Safety Analysis Report supplement accordingly.

Response

The actions described above that are found to be necessary to maintain program effectiveness will be continued during the timely renewal period and period of extended operation.

The Service Water Integrity Program description in LRA B.1.34 and the corresponding FSAR supplements in LRA A.2.1.33 and A.3.1.33 are revised as shown, although these activities are below the level of detail typically provided in the description of an aging management program and the corresponding FSAR supplement.

RAI 3.0.3-5

Background:

The response to RAI 3.0.3 1 dated December 16, 2014, states that the fire protection water and city water systems have experienced recurring internal corrosion (RIC), as defined in LR-ISG-2012-02. With regard to the fire protection water system, the response states, "[l]ocalized corrosion has resulted in minor through-wall leaks that have no impact on system performance and do not threaten the structural integrity of the piping or the safety function of nearby equipment." No changes were proposed to the Fire Water System Program to address RIC. With regard to the city water system, the response states, "[h]owever, based on past operating experience, they [through wall leaks] do not compromise the intended functions of these or any other system, and do not warrant aging management program activities beyond those provided by established aging management programs and the corrective action program."

Issue:

Past performance does not provide reasonable assurance that throughout the period of extended operation, internal general corrosion will be revealed by a through-wall leak prior to the general corrosion potentially impacting the structural integrity of the system. Nor does it provide reasonable assurance that larger through-wall flaws sufficient to challenge the pressure boundary function will not occur. It is also unclear to the staff that a sufficient representative sample exists for the carbon steel piping to demonstrate that general corrosion is progressing slowly enough that it will not prevent an in-scope component from performing its current licensing basis intended function during the period of extended operation.

Although to date through-wall leaks have not affected the safety function of nearby equipment, the staff lacks sufficient information to conclude with reasonable assurance that this will be the case throughout the period of extended operation.

Request:

1) State the basis and justification for concluding that existing inspection data are sufficient to demonstrate that general corrosion is progressing slowly enough that it will not prevent an in-scope component from performing its current licensing basis intended function during the period of extended operation.

2) State the basis and justification for concluding that through-wall leaks will not impact the safety function of nearby equipment throughout the period of extended operation.

3) Provide the staff with sufficient quantitative data for it to reach the same conclusion. Alternatively, propose periodic inspections in response to SRP-LR Section 3.3.2.2.8, "Loss of Material due to Recurring Internal Corrosion."

Response to RAI 3.0.3-5

1) The IP2 fire water system consists of piping originally installed for IP1 (*circa* 1955), the additional fire water piping installed for IP2 (*circa* 1970), and the city water piping that is the supply/suction piping for the fire main pumps and pressure maintenance pumps. Both the

city water system and fire protection system at IPEC are filled with treated water that is supplied by the Town of Buchanan, NY municipal water system. This potable water is tested periodically by the Town to ensure its quality. It is non-corrosive. Therefore, internal corrosion rates in these systems have historically been low and are expected to remain low. As discussed below, recent inspection data confirm that corrosion rates are low and unlikely to prevent an in-scope component from performing its current licensing basis (CLB) intended function during the period of extended operation (PEO).

As documented in a May 2013 engineering report, IPEC evaluated non-destructive examination ultrasonic testing (NDE UT) data collected from a broad cross-section of aboveground IP2 fire water system piping to identify evidence of loss of material due to internal corrosion. The review examined NDE UT data from 14 locations (nine Unit 1 locations and five Unit 2 locations) to provide a representative sample of the fire water piping for evaluation of internal piping conditions. IPEC performed this evaluation to satisfy License Renewal Commitment No. 8, as contained in Attachment 3 (List of Regulatory Commitments, Rev. 26) to NL-15-019, dated March 10, 2015.

The specific results of the NDE UT examinations are summarized in Part 3 of this RAI response. As stated in the May 2013 report, the evaluation concluded that: (1) for all of the sample locations, the calculated remaining life of the IP2 piping, without exceeding the allowable minimum wall thickness (T_{min}), is greater than the 20-year PEO; (2) internal corrosion rates, as conservatively calculated based on observed degradation, are not expected to cause the piping to exceed the structural integrity T_{min} during the 20-year PEO; and (3) both the above- and below-grade fire protection piping (which includes the city water piping that is the supply/suction piping for the fire main booster pumps and pressure maintenance pumps) are bounded by the evaluation. The report further concludes that continuing evaluation of the IP2 fire protection water piping via NDE UT examination during the IP2 PEO is not warranted based on projected corrosion rates.

Based on the results of the engineering evaluation, Entergy concludes that current inspection data are sufficient to demonstrate that general corrosion is progressing slowly enough that it will not prevent an in-scope component from performing its CLB intended function during the PEO. Entergy notes that in May 2013, the NRC inspected activities conducted by Entergy to complete IP2 license renewal commitments, including License Renewal Commitment No. 8. NRC Inspection Report 05000247 / 2013009 states that the inspectors reviewed the May 2013 engineering report, the NDE UT examination data records, and the associated structural assessments of minimum wall thickness and corrosion rate determinations. The inspectors compared the UT data results to the established minimum wall thickness criteria for the selected piping locations to verify adequate pressure boundary and structural integrity of the fire water piping system. The inspectors also evaluated Entergy's determination that the wall thickness at UT test locations would remain greater than the minimum required wall thickness at the end of the PEO, based upon worst-case test results and conservative estimates of corrosion rates.

In addition, the inspectors evaluated the locations Entergy selected for UT examination of fire water piping to verify the locations were sufficiently diverse and represented an adequate sample population to ensure the test results were indicative of the piping system as a whole. The inspectors walked down all UT test locations and other portions of the fire water system to independently assess the material condition of the fire water piping.

Inspection Report 05000247 / 2013009 states that no findings were identified. Thus, the NRC inspection findings support Entergy's conclusion that inspection data are sufficient to demonstrate that general corrosion is progressing slowly enough that it will not prevent an in-scope component from performing its CLB intended function during the PEO.

Entergy considers the engineering evaluation results documented in the May 2013 report as representative of both IP2 and IP3 piping, given that the piping was installed in accordance with similar piping specifications. Also, the piping material and the treated water are the same for both IP2 and IP3. Finally, the relevant operating experience for both systems has been similar. This provides assurance that general corrosion will not prevent the IP3 fire protection water and city water systems from performing their CLB intended functions during the PEO.

2) As discussed above, NDE UT inspection data confirm that general corrosion of the fire protection piping and city water piping is progressing slowly enough that it will not prevent an in-scope component from performing its CLB intended function during the PEO. In addition to the previous review of 10 years of plant operating experience, a review of IPEC Unit 2 and Unit 3 LERs issued over the 12-year period from 1/1/2003 to 5/24/2015 identified no cases in which leaks in fire protection or city water piping caused the unavailability or inoperability of safety-related systems or components.

   Although some pinhole leaks in piping have occurred due to localized pitting corrosion, that corrosion mechanism is localized (not severe) and would rarely, if ever, affect the structural integrity of the piping. Further, NDE exams typically are performed to confirm that degradation associated with through-wall leaks is localized, and to confirm the integrity of the piping. The supporting UT exam results have demonstrated that gross general corrosion is not occurring, and that the piping remains structurally sound.

   The May 2013 engineering evaluation results, the recent LER review, and plant operating experience support the conclusions that potential corrosion issues will be adequately managed by existing programs, and that the likelihood is low that through-wall leaks in fire protection and city water piping will impact the safety function of nearby equipment.

3) As noted in the Part 1 response above, the May 2013 engineering evaluation evaluated NDE UT data from 14 locations providing a representative sample of internal piping conditions in the fire water piping. Both original IP1 piping and later-installed IP2 piping locations were included in the sample.

   The UT reports that indicated as-found pipe wall thicknesses greater than 87.5% were considered acceptable with no further evaluation. The UT reports with one or more points of the as-found pipe wall thickness less than 87.5% of nominal wall thicknesses were subjected to further evaluation, because indications of less than nominal wall thickness suggest possible degradation.

   NDE UT data for eight of the sample points (three Unit 1 and five Unit 2 locations) indicated no degradation of the piping below the accepted fabrication tolerance for piping wall thickness of 87.5% of nominal. NDE UT data for six of the sample points (all Unit 1 piping) indicated wall thinning below 87.5% of nominal, but in all cases, the pipe wall was significantly greater than the calculated minimum (T_{min}) for piping structural integrity.

Extrapolation of the evaluated data, assuming a continuing degradation rate consistent with the as-found condition of the piping, determined that in all cases, the degradation of the piping is not expected to result in wall thickness that is less than the structural integrity T_{min} during the IP2 20-year PEO. For those six points, the remaining calculated life varied between 29 and 94 years.

Entergy considers the engineering evaluation results documented in the May 2013 report as representative of both IP2 and IP3 piping, given that the piping was installed in accordance with similar piping specifications. Also, the piping material and the treated water are the same for both IP2 and IP3. Finally, the relevant operating experience for both systems has been similar.

Based on the May 2013 evaluation of the piping and the NRC's related inspection activities (as documented in Inspection Report 05000247 / 2013009), it is reasonable to conclude that general corrosion is progressing sufficiently slowly that it will not prevent in-scope components from performing their CLB intended functions during the PEO, and the likelihood of through-wall leaks that could impact the safety function of nearby equipment during the PEO is low.

RAI 3.0.3-6

Background:

As amended by letter dated December 16, 2014, LRA Section B.1.14 states an exception to the "detection of aging effects" program element. This exception states that adhesion testing will not be conducted on the internal surfaces of fire water storage tanks in accordance with ASTM D 3359, "Standard Test Methods for Measuring Adhesion by Tape Test," as required by NFPA 25 Section 9.2.7. The justification for the exception states in part that holiday testing and wall thickness measurements are conducted. It also states that adhesion testing, in accordance with ASTM D 3359, would not be conducted because the recommended type of adhesion testing is destructive and test results are variable.

Issue:

An alternative to adhesion testing was not proposed.

Request:

State how potential peeling, delamination, or blistering, or the extent of these aging mechanisms, would be detected by holiday testing or ultrasonic wall thickness measurements, or propose an alternative to the adhesion testing cited in NFPA 25.

Response to RAI 3.0.3-6

Dry film thickness and spot wet-sponge tests are used to identify holidays in coatings. Neither holiday testing nor ultrasonic wall thickness measurements are credited for detection of all forms of loss of coating integrity. The initial manifestations of loss of coating integrity, such as peeling, delamination and blistering, on the fire water tank interior coating are detected using a visual inspection per NFPA 25 (2011 Edition) Section 9.2.6.4. Adhesion testing is used as appropriate in evaluating the condition of degraded coatings identified through visual inspection or holiday testing. In accordance with the corrective action program, any signs of coating/tank degradation require evaluation to assess the extent of degradation and determine if the tank can be returned to service without repairing, replacing or removing the defective coating. If the fire water tank is returned to service without repairing, replacing or removing the coating, a coating specialist, qualified in accordance with an ASTM international standard endorsed by Regulatory Guide (RG) 1.54, and design engineering evaluate the extent of the coating degradation and must conclude that the coating condition will not prevent the tank from performing its design function until the next inspection.

The qualified coating inspector and design engineering determine the testing necessary to adequately evaluate coating condition. For example, ASTM D714-87, or a later revision, would be used to categorize the blisters according to size and frequency. A fire water tank with blisters in the coating would only be returned to service after a qualified coating inspector has determined there are only a few small intact blisters that are completely surrounded by sound coating bonded to the substrate. Although the testing may include destructive adhesion testing as described in ASTM D3359, non-destructive adhesion testing is preferred. The type of adhesion testing is based on evaluation of the specific condition.

The coating system applied to the IPEC fire water tanks consists of multiple layers. The acceptance criteria for the coating within the fire water tank are no more than a few small intact blisters that are completely surrounded by coating bonded to the substrate, and no delamination or peeling. The fire water tank would only be returned to service with coating defects after the following actions are taken:

1. The blistered, delaminated, or peeled coating is removed.
2. The exposed underlying coating is verified to be securely bonded to the substrate as determined by an adhesion test endorsed by RG 1.54 at a minimum of three locations adjacent to the defective area.
3. The outermost coating is feathered and the remaining outermost coating is determined to be securely bonded to the coating below via an adhesion test endorsed by RG 1.54 at a minimum of three locations adjacent to the defective area.
4. Ultrasonic testing is performed where there is evidence of pitting or corrosion.
5. An evaluation is performed to ensure downstream flow blockage is not a concern.
6. A follow-up inspection is scheduled to be performed within two years and every two years after that until coating is repaired, replaced or removed.

RG 1.54 describes the use of ASTM test standard D 4541-09, "Pull-Off Strength of Coatings Using Portable Adhesion Testers" as an acceptable alternative method for performing adhesion testing of coatings on metal substrates using a fixed-alignment adhesion tester. In addition, lightly tapping, scraping or cleaning the degraded area per Society of Protective Coatings (SSPC), SSPC-SP2 Hand Tool Cleaning, SSPC-SP3 Power Tool Cleaning, SSPC SP11 Cleaning of Bare Metal, and SSPC-SP WJ-1, 2, 3 and 4 Water Jet Cleaning allow a qualified inspector and design engineering the ability to determine the extent of peeling, delamination and blistering to ensure that downstream flow blockage and tank integrity are not an issue. If there is evidence of pitting or corrosion, then ultrasonic thickness measurements of the affected areas are performed to confirm that the tank wall thickness is sufficient to perform its pressure boundary function.

The following enhancements will be added to the Fire Water System Program.

- Revise Fire Water System Program procedures to determine the extent of coating defects on the interior of the fire water tanks by using one or more of the following methods when conditions such as cracking, peeling, blistering, delamination, rust or flaking are identified during visual examination.

  1. Lightly tapping and scraping the coating to determine coating integrity.
  2. Wet-sponge testing or dry film testing to identify holidays in the coating.
  3. Adhesion testing in accordance with ASTM D3359, ASTM D4541, or equivalent testing endorsed by RG 1.54 at a minimum of three locations.
  4. Ultrasonic testing where there is evidence of pitting or corrosion to determine if the tank thickness meets the minimum thickness criteria.

- Revise the Fire Water System Program procedures to ensure a fire water tank is not returned to service after identifying interior coating blistering, delamination or peeling unless

there are only a few small intact blisters surrounded by coating bonded to the substrate as determined by a qualified coating inspector, or the following actions are performed:

1) Any blistering in excess of a few small intact blisters, or blistering not completely surrounded by coating bonded to the substrate is removed.
2) Any delaminated or peeled coating is removed.
3) The exposed underlying coating is verified to be securely bonded to the substrate as determined by an adhesion test endorsed by RG 1.54 at a minimum of three locations.
4) The outermost coating is feathered and the remaining outermost coating is determined to be securely bonded to the coating below via an adhesion test endorsed by RG 1.54 at a minimum of three locations adjacent to the defective area.
5) Ultrasonic testing is performed where there is evidence of pitting or corrosion to ensure the tank meets minimum wall thickness requirements.
6) An evaluation is performed to ensure downstream flow blockage is not a concern.
7) A follow-up inspection is scheduled to be performed within two years and every two years after that until the coating is repaired, replaced, or removed.

RAI 3.0.3-7

Background:

As amended by letter dated December 16, 2014, LRA Section B.1.14 states an exception to the "detection of aging effects" program element. The exception states that preaction valve testing is not conducted with the control valve fully open for the electric tunnels as specified by NFPA 25 Section 13.4.3.2.3.

Issue:

The staff lacks sufficient information to conclude that adequate flow to detect potential flow blockage will be achieved during the test. The staff also noted that NFPA 25 Section 13.4.3.2.2.5 allows air to be used as a test medium when the nature of the protected property is such that water cannot be discharged.

Request:

State and justify the basis for why flow rates sufficient to detect flow blockage will be achieved during preaction valve testing.

Response to RAI 3.0.3-7

The fire water system for the electric tunnel is a preaction system (i.e., the spray heads downstream of the preaction valve are of the closed head type). The piping downstream of the preaction valve is normally dry and the spray heads would open only when the fusible link melts. The Fire Water System Program procedures will be enhanced to remove a sprinkler head at the end of a branch line to perform an air test when cycling the electric tunnel preaction valve to ensure there is no downstream flow blockage.

RAI 3.0.3-8

Background:

As amended by letter dated December 16, 2014, an enhancement to LRA Section B.1.14 was revised to state that the acceptance criteria used during the internal inspection of foam based fire suppression tanks will be signs of abnormal corrosion.

Issue:

The staff lacks sufficient information to complete its evaluation of the acceptance criteria portion of this enhancement because abnormal corrosion is not described.

Request:

State the magnitude of corrosion that would be considered unacceptable during the inspection of internal surfaces of foam based fire suppression tanks.

Response to RAI 3.0.3-8

The letter dated December 16, 2014, states: "In addition, visual inspection results that identify excessive accumulation of corrosion products and appreciable localized corrosion (e.g., pitting) beyond a normal oxide layer will be entered into the corrective action program, and a follow-up volumetric wall thickness examination will be performed." This acceptance criterion also applies to the internal visual inspection of the foam-based fire suppression tanks and is part of the program description for the Fire Water System Program in SAR supplement Sections A.2.1.13 and A.3.1.13.

RAI 3.0.3-9

Background:

As amended by letter dated December 16, 2014, an enhancement to LRA Section B.1.14 states that sprinkler heads will be replaced if they show signs of abnormal corrosion, excessive loading, leakage, or if the glass bulb heat responsive element is empty. LRA Section B.1.14 was also amended to state that charcoal filter unit nozzles will be inspected for abnormal corrosion when the charcoal is replaced.

Issue:

The staff notes that NFPA 25, Sections 5.2.1.1.2(2) and 5.2.1.1.4 state that sprinklers that exhibit corrosion, not "abnormal corrosion" should be replaced.

Request:

a) Describe the degree of corrosion that would be found acceptable during a visual inspection of a sprinkler and justify why this degree of corrosion would not impact the performance of the sprinkler (e.g., water distribution).

b) Describe the degree of corrosion that would be found acceptable during a visual inspection of charcoal filter nozzles and justify why this degree of corrosion would not impact the performance of the charcoal filter deluge system.

Response to RAI 3.0.3-9

a) In accordance with NFPA 25 (2011 Edition) Section 5.2.1.1.2 and Section 5.2.1.1.4, sprinkler heads will be replaced if they show any signs of leakage, corrosion, physical damage, loss of fluid, or loading. In lieu of replacing sprinklers that are loaded with a coating of dust, it is permitted to clean sprinklers with compressed air or by vacuum provided that the equipment does not touch the sprinkler.

b) It has been determined the IP3 charcoal filter fire suppression systems and IP2 primary auxiliary building and containment ventilation charcoal filter fire suppression systems do not have nozzles within the charcoal filter units. Fire water is distributed through a series of holes in the piping within the charcoal filter beds. The IP2 technical support center charcoal filter fire suppression system unit has nozzles within the charcoal filtration units. The accessible portions of this piping and nozzles are inspected during routine charcoal sampling. Signs of corrosion beyond normal surface corrosion will be entered into the corrective action program and evaluated to ensure the components can perform their intended function.

LRA Sections A.2.1.13, A.3.1.13, and B.1.14 are revised accordingly.

RAI 3.0.3-10

Background:

As amended by letter dated December 16, 2014, an enhancement to LRA Section B.1.14 states that air flow testing will be conducted during each refueling outage through the foam system open head nozzles to ensure there is no blockage. It also states that if blockage is detected, the system will be cleaned and retested.

Issue:

The staff notes that LR ISG 2012 02 AMP 27, Table 4a recommends that an operational discharge pattern test be conducted annually in accordance with NFPA 25 Section 11.3.2.6, Table 4a footnote 6 states that, "[w]here the nature of the protected property is such that foam cannot be discharged, the nozzles or open sprinklers shall be inspected for correct orientation and the system tested with air to ensure that the nozzles are not obstructed." A justification was not provided for testing every refueling outage in lieu of annual testing.

Request:

Provide a justification as to why the frequency for testing the foam system open head nozzles every refueling outage in lieu of annually is acceptable.

Response to RAI 3.0.3-10

In order to perform air flow testing of the foam system through the foam system open head nozzles, the system must be taken out of service. To minimize the risk associated with taking the system out of service, it is reasonable to coordinate the air flow testing with a refueling outage. In addition, operating experience indicates no history of obstructions or incorrect orientation of these nozzles. Therefore, inspecting the foam system open head nozzles every refueling outage provides reasonable assurance that the nozzles are oriented correctly and there are no blockages.

<u>RAI 3.0.3-11</u>

<u>Background</u>:

As amended by letter dated December 16, 2014, an enhancement to LRA Section B.1.14 states that in buildings' with multiple wet piping systems, one third of the systems will be inspected every five years such that all systems will be inspected during each 15 year period.

<u>Issue</u>:

A justification was not stated for inspecting one third of the systems where there are multiple wet pipe systems in lieu of every other system as cited in NFPA 25 Section 14.2. In addition, the enhancement does not state whether all the systems in a building will be inspected if foreign organic or inorganic material is found in any system in that building.

<u>Request</u>:

Provide a justification as to why testing one third of the systems every 5 years and not testing all the systems in a building when foreign organic or inorganic material is found in any system in that building is sufficient to provide reasonable assurance that the wet fire water system piping and piping components will meet their current licensing basis intended functions during the period of extended operation.

<u>Response to RAI 3.0.3-11</u>

Each wet pipe sprinkler system in IP2 and IP3 is supplied by the respective unit fire water supply, which ultimately comes from the same fire water source. The aging effects in the systems are expected to be the same because the systems are fabricated from the same material and exposed to the same environment. Therefore, test results from one third of the systems in each building every five years are representative of the other systems and provide reasonable assurance that the wet pipe sprinkler systems will perform their current licensing basis function during the period of extended operation. In the event foreign organic or inorganic material is found during any of the wet pipe systems tested in a building, the inspection scope will be expanded to include the other wet pipe systems in that building.

LRA Sections A.2.1.13, A.3.1.13, and B.1.14 require internal inspections at the end of one fire main and the end of one branch line on one third of the wet pipe systems in each building. During each five-year period, different wet pipe sprinklers will be inspected such that all of the wet pipe sprinkler systems in each building will be internally inspected every 15 years. In the event internal obstructions are identified in a building wet pipe system, the inspection scope will be expanded to include all of the wet pipe sprinkler systems in that building. Performing the above inspections provides reasonable assurance that the wet pipe sprinkler systems will perform their intended function during the period of extended operation and meets the intent of NFPA 25 (2011 Edition) Section 14.2.2.

LRA Sections A.2.1.13, A.3.1.13, and B.1.14 are revised to include this guidance.

RAI 3.0.3-12

Background:

As amended by letter dated December 16, 2014, LRA Section B.1.14 states, "[i]n addition to NFPA codes, portions of the water-based fire protection system (a) that are normally dry but periodically subject to flow (e.g., dry-pipe or preaction sprinkler system piping and valves) and (b) that cannot be drained or allow water to collect are subject to augmented testing and inspections."

Issue:

LRA Sections A.1.14 and B.1.14 do not state what augmented testing will be conducted. In addition, the staff noted that there were no enhancements associated with this program requirement.

Request:

a) State what augmented testing and inspections will be conducted for fire protection water systems that are normally dry but periodically subject to flow (e.g., dry-pipe or preaction sprinkler system piping and valves) that cannot be drained or allow water to collect.

b) State whether an enhancement is necessary to incorporate these augmented tests and inspections.

c) Revise the LRA Section A.1.14 or B.1.14 as necessary.

Response to RAI 3.0.3-12

Based on the results of an inspection of the dry portions of the fire water system, IPEC LRA Sections A.2.1.13, A.3.1.13 and B.1.14, Fire Water System, shall be revised to remove the provisions for these augmented inspections. It was determined that the periodically wetted dry IPEC fire water systems are configured to drain properly, and are in fact drained via station procedures before returning them to service after testing. In addition, an enhancement to the Fire Water System Program requires the performance of an air test when cycling the preaction and deluge valves to ensure there is no flow blockage downstream. Therefore, no augmented inspections or revisions to the LRA are needed.

RAI 3.0.3-13

Background:

As amended by letter dated December 16, 2014, LRA Sections A.2.1.13 and A.3.1.13 state that the enhancements to the Fire Water System Program will be implemented by December 31, 2019.

Issue:

As stated in RAI 3.0.3 12, it is not clear whether an enhancement is necessary to address augmented testing for fire protection water systems that are normally dry but periodically subject to flow (e.g., dry-pipe or preaction sprinkler system piping and valves) that cannot be drained or allow water to collect. SRP LR Table 3.0 1, as amended by LR ISG 2-12 02, states that the augmented testing should commence 5 years prior to the period of extended operation. Given that IP2 is beyond the expiration of its initial license (September 2013) and IP3 will be beyond its initial license period in December 2015, the staff questions why the augmented testing would not commence sooner than December 31, 2019.

Request:

State and justify the basis for why the augmented testing for fire protection water systems that are normally dry but periodically subject to flow (e.g., dry-pipe or preaction sprinkler system piping and valves) that cannot be drained or allow water to collect will not commence until December 31, 2019.

Response to RAI 3.0.3-13

As stated in the response to RAI 3.0.3-12, there are no IPEC fire water systems that are normally dry but periodically subject to flow that cannot be drained or that allow water to collect. Therefore, this augmented testing is not necessary at IPEC. The response to RAI 3.0.3-12 includes revised LRA Sections A.2.1.13, A.3.1.13, and B.1.14 to delete the statement about augmented testing.

RAI 3.0.3-14

Background:

By letter dated December 16, 2014, the Aboveground Steel Tanks Program was enhanced to develop or revise program implementation documents to incorporate the inspection details that are tabulated in the program description. The tabulated tank inspection techniques and frequencies are provided for each applicable material, environment, and aging effect. The enhancement will be implemented prior to December 31, 2019. An exception was also added to the program stating that the timing of the inspections will not be consistent with the guidance in LR-ISG-2012-02. The exception noted that the implementation schedule for the inspections could not be consistent with LR-ISG-2012-02 because of the date that the guidance was issued. The enhancement will be implemented prior to December 31, 2019. The initial operating license for Unit 2 expired in September of 2013. The initial operating license for Unit 3 will expire in December of 2015.

LR-ISG-2012-02 was issued in November of 2013. The implementation schedule in SRP LR Table 3.0 1, as amended by LR ISG 2-12 02, for GALL Report AMP XI.M29 states that the program is implemented and inspections begin 10 years before the period of extended operation. Additionally, Table 4a, in GALL Report AMP XI.M29, as amended by LR ISG 2012 02, provides inspection frequencies that begin 10 years prior to the period of extended operation.

Issue:

LRA Sections A.2.1.1, A.3.1.1, and B.1.1 state that the program enhancements will be implemented prior to December 31, 2019. Given that the inspections recommended to be performed prior to entering the period of extended operation have not occurred, IP2 is beyond the expiration of its initial license (September 2013), and IP3 will be beyond its initial license period in December 2015, it is unclear to the staff why the inspections in the enhancement might not be implemented until late 2019 rather than earlier.

Request:

State the basis and justify why implementation of inspections described in the program description do not need to be implemented until December 31, 2019.

Response to RAI 3.0.3-14

The timing of inspections identified in LR-ISG-2012-02, Table 4a, are tied to the date a particular unit will enter the period of extended operation (PEO). For both IPEC units, the date of entering the PEO was not a realistic date for implementing the program enhancements from the ISG. Specifically, IP2 has already entered the PEO and IP3 enters the PEO in December 2015, less than six months from now. Therefore, the responses to RAI set #2014-01, letter dated December 16, 2014, identified December 31, 2019, as a realistic implementation date to be treated in the same manner as a date for entering the PEO. Where the ISG specifies activities to be completed "prior to the period of extended operation," those activities at IPEC for both units will be completed prior to December 31, 2019.

The ISG provided a ten-year window in which to perform the first inspections prior to the period of extended operation. Since IPEC did not have ten years from the time the RAI was received, a five-year period was deemed reasonable. The five-year period (December 2014 through December 2019) allows for two outages for each unit in which to perform the specified inspections, some of which may necessitate an outage. The scope of an outage is established many months in advance to allow for adequate planning and coordination with system and train outages, etc. Given that the ISG provided a ten-year window for the first inspections, the five-year window for IPEC is reasonable to allow for adequate planning and scheduling around and within outage windows.

The implementation date of "prior to December 31, 2019," allows for the following activities to occur.

- Planning the activities specified in the ISG as ordinarily being performed prior to the PEO.
    - Revising procedures to include the enhancements described in LRA Sections A.2.1.1, A.3.1.1, and B.1.1.
    - Ensuring availability of test equipment as needed.
- Scheduling and completing the activities specified in the ISG as ordinarily being performed prior to the PEO.
    - Working with two units, each with two-year operating cycles affecting opportunities for tank inspections.
    - Multiple tank surfaces and inspection techniques.
- Assessing the results from the activities specified in the ISG as ordinarily being performed prior to the PEO.
    - Determining corrective actions as needed.
    - Establishing scope and frequency for future activities.
- Planning and scheduling the activities specified in the ISG to be performed during the PEO.
    - Evaluating the necessity of subsequent 10-year inspections as stated in RAI response Notes 9 and 11 to the tank inspection table in LRA Sections A.2.1.1, A.3.1.1, and B.1.1.
    - Scheduling inspections for refueling outages.
    - Scheduling 10-year inspections as specified.

The approach discussed herein is consistent with the discussion of enhancements to other programs in the IPEC LRA Appendix A and B (stated as, "Enhancements will be implemented prior to the period of extended operation") where the following is understood:

- "Prior to the PEO" activities will be completed prior to the implementation date.
- Results of the "prior to the PEO" activities will be assessed to establish scope and frequency for future activities as specified.

- "During the PEO activities" will be planned prior to the implementation date.

RAI 3.0.3-15

Background:

By letter dated December 16, 2014, LRA Table 3.3.2-14-IP2, "City Water, Summary of Aging Management Review," was revised. The table includes an AMR item for steel tanks exposed to an internal environment of treated water that was revised to manage the aging effect of loss of material using the Aboveground Steel Tanks Program instead of the Periodic Surveillance and Preventative Maintenance Program. This AMR item cites generic note G and plant specific note 305. Plant specific note 305 states that "This treated water environment includes water that has been treated but is not maintained by a chemistry control program, such as water from the city water system. There is no environment in NUREG-1801 that will support a useful comparison for this line" item.

Section IX.D, "Selected Definitions & Use of Terms for Describing and Standardizing Environments," of GALL Report, revision 2, provides descriptions of treated water and raw water. Treated water includes demineralized water or water containing corrosion inhibitors. Raw water includes potable water and water used for drinking or other personal use.

GALL Report AMP XI.M29, "Aboveground Metallic Tanks," as amended by LR-ISG-2012-02 provides different guidance for managing the loss of material for steel tanks exposed to treated water and raw water. The differences are illustrated in Table 4a, "Tank Inspection Reconditions," and AMR line items 3.3.1-129 and 3.3.1-137.

Issue:

The environment of city water is being categorized as treated water; however, city water appears to more closely resemble raw water. The aging management of loss of material for steel tanks exposed to treated water is not equivalent to that exposed to raw water in that steel exposed to treated water may use a one time inspection to verify aging effects, whereas for steel exposed to raw water it is recommended that periodic inspections be conducted.

Request:

State the basis and justify why city water is being categorized as treated water instead of raw water. Additionally, state the basis and justify why steel tanks exposed to city water are being managed for loss of material in accordance with LR-ISG-2012-02 inspection guidance for treated water instead of raw water.

Response to RAI 3.0.3-15

The Environment column entries in LRA Table 3.3.2-17-IP2, "City Water, Summary of Aging Management Review," are the environments used in the evaluation of applicable aging effects for the material/environment combination. These environments generally align with those used in NUREG-1801, Revision 1, except for treated water. As identified in footnote 1 of LRA Table 3.0-1, treated water encompasses a range of water types, all of which were chemically treated or demineralized. City water was categorized as treated water instead of raw water because the aging effects resulting from material exposed to city water more closely align with those resulting from exposure to treated water than to raw water.

Plant-specific note 305 states that the "treated water" in this item was treated but is not maintained by a chemistry control program, indicating that it is different from treated water as defined by NUREG-1801. This difference was considered for the determination of the program used to manage loss of material. Consequently, periodic inspections were originally delineated under the Periodic Inspection and Preventive Maintenance Program.

The change to the Aboveground Metallic Tanks Program made in the December 16, 2014, letter from Entergy did not modify plant-specific note 305 since the difference from treated water as defined by NUREG-1801 was still relevant. There was no intent to redefine treated water in this item to match treated water as used in LR-ISG-2012-02, Table 4a, "Fire Water System Inspection and Testing Recommendations." However, the tables defining Aboveground Metallic Tank Program inspection details for LRA Sections A.2.1.1 and B.1.1 did not include the appropriate lines delineating the inspection details for the city water tank. Therefore, the tables in LRA Sections A.2.1.1 and B.1.1 are revised to add a line item specifically for the city water tank that will require periodic inspections.

ATTACHMENT 2 TO NL-15-092

LICENSE RENEWAL APPLICATION

CHANGES DUE TO RESPONSES TO REQUESTS FOR INFORMATION

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

Revisions to LRA text and tables are provided below with additions underlined and deletions marked through.

A.2.1.1 Aboveground Steel Tanks Program

The Aboveground Steel Tanks Program will be enhanced to include the following tank inspection details[1].

Material	Environment	AERM	Inspection Technique[2]	Inspection Frequency
Inspections to identify degradation of inside surfaces of tank shell, roof[3], and bottom inside surface (IS), outside surface (OD)[4, 5]				
Steel	Raw water (city water)	Loss of material	Volumetric from OS[6] or visual from IS	Each 10-year period of the period of extended operation

6. At least 25 percent of the tank surface is inspected using a method capable of precisely determining wall thickness. The inspection method should be demonstrated capable of detecting both general and pitting corrosion.

A.2.1.13 Fire Water System Program

The Fire Water System Program is an existing program that manages water-based fire protection systems that consist of sprinklers, nozzles, fittings, valves, hydrants, hose stations, fire pump casings, water storage tanks, standpipes, piping, and components that are tested in accordance with applicable National Fire Protection Association (NFPA) codes. Such testing assures functionality of systems. To determine if abnormal corrosion has occurred in water-based fire protection systems, periodic flushing, system performance testing and inspections are conducted. ~~In addition to NFPA codes, portions of the water-based fire protection system (a) that are normally dry but periodically subject to flow (e.g., dry-pipe or preaction sprinkler system piping and valves) and (b) that cannot be drained or allow water to collect are subject to augmented testing and inspections.~~ Also, many of these systems are normally maintained at required operating pressure and monitored such that leakage resulting in loss of system pressure is immediately detected and corrective actions initiated.

- Revise Fire Water System Program procedures to inspect the ~~nozzles~~water distribution piping inside the charcoal filter units for ~~abnormal~~ corrosion when the charcoal is replaced. In the event the amount of corrosion exceeds normal surface corrosion, enter the condition into the corrective action program. (Refer to NFPA-25 (2011 Edition), Section~~s 13.4.3.2.2 and~~ 14.2.)

- Revise Fire Water System Program procedures to inspect for and require replacement of sprinkler heads (nozzles) if they show signs of ~~abnormal~~ corrosion, ~~excessive~~ loading*, leakage, or if the glass bulb heat responsive element is found empty. (Refer to NFPA-25 (2011 Edition), Section 5.2.1.1.)

  * In lieu of replacing a loaded sprinkler head, sprinklers that are loaded with a coating of dust can be cleaned with compressed air or by vacuum provided that the equipment does not touch the sprinkler head.

- Revise Fire Water System Program procedures to inspect the accessible portions of the water distribution piping inside the charcoal filter units for corrosion when the charcoal is sampled. In the event the amount of corrosion exceeds normal surface corrosion, enter the condition into the corrective action program.

- Revise Fire Water System Program procedures to inspect the interior and exterior of the fire water storage tanks in accordance with NFPA 25 (2011 Edition), Sections 9.2.5.5, 9.2.6 and 9.2.7, with the exception of NFPA (2011 Edition) Sections 9.2.7.1 and 9.2.7.6. In lieu of testing specified in Section 9.2.7.1, alternate adhesion testing endorsed by Regulatory Guide (RG) 1.54 may be performed ~~perform holiday testing~~. In lieu of testing specified in Section 9.2.7.6, perform ultrasonic thickness checks or mechanical measurements of any identified corroded areas at least once every five years.

- Revise Fire Water System Program procedures to determine the extent of coating defects on the interior of the fire water tanks by using one or more of the following methods when conditions such as cracking, peeling, blistering, delamination, rust or flaking are identified during visual examination.

  1. Lightly tapping and scraping the coating to determine the coating integrity.
  2. Wet-sponge testing or dry film testing to identify holidays in the coating.
  3. Adhesion testing in accordance with ASTM D3359, ASTM D4541, or equivalent testing endorsed by RG 1.54 at a minimum of three locations.
  4. Ultrasonic testing where there is evidence of pitting or corrosion to determine if the tank thickness meets the minimum thickness criteria.

- Revise the Fire Water System Program procedures to ensure a fire water tank is not returned to service after identifying interior coating blistering, delamination or peeling unless there are only a few small intact blisters surrounded by coating bonded to the substrate as determined by a qualified coating inspector, or the following actions are performed:

  1) Any blistering in excess of a few small intact blisters, or blistering not completely surrounded by coating bonded to the substrate is removed,
  2) Any delaminated or peeled coating is removed,
  3) The exposed underlying coating is verified to be securely bonded to the substrate as determined by an adhesion test endorsed by RG 1.54 at a minimum of three locations,
  4) The outermost coating is feathered and the remaining outermost coating is determined to be securely bonded to the coating below via an adhesion test endorsed by RG 1.54 at a minimum of three locations adjacent to the defective area,
  5) Ultrasonic testing is performed where there is evidence of pitting or corrosion to ensure the tank meets minimum wall thickness requirements,
  6) An evaluation is performed to ensure downstream flow blockage is not a concern, and
  7) A follow-up inspection is scheduled to be performed within two years and every two years after that until the coating is repaired, replaced, or removed.

- Revise IP2 Fire Water System Program procedures to remove a sprinkler head at the end of a branch line and perform an air test to ensure there is no downstream flow blockage when performing the electric tunnel preaction valve testing prescribed in NFPA 25 (2011 Edition), Section 13.4.3.2.3.

- Revise Fire Water System Program procedures to perform an internal inspection of wet fire water system piping conditions every five years, or after an extended shutdown of greater than one year, by opening a flushing connection at the end of one main and by removing a closed sprinkler toward the end of one branch line for the purpose of inspecting the interior for evidence of loss of material and the presence of foreign organic and inorganic material that could result in flow obstructions or blockage of sprinkler heads or nozzles. In the event there are multiple wet pipe systems in a structure, one third will be inspected every five years such that all systems will be inspected during each 15-year period. The procedures will include (1) guidance to perform an evaluation for MIC in the event tubercles or slime are identified, and (2) acceptance criteria that states "no abnormal debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged). Corrective actions will specify that any signs of abnormal corrosion or blockage will be removed and the condition will be entered into the corrective action program~~,~~. Inspection scope will be expanded to include all of the wet pipe sprinkler systems in that building and the source and extent of condition determined and corrected~~, and entered into the corrective action program~~. (Refer to NFPA-25 (2011 Edition), Section 14.2.)

A.3.1.13 Fire Water System Program

The Fire Water System Program is an existing program that manages water-based fire protection systems that consist of sprinklers, nozzles, fittings, valves, hydrants, hose stations, fire pump casings, water storage tanks, standpipes, piping, and components that are tested in accordance with applicable National Fire Protection Association (NFPA) codes. Such testing assures functionality of systems. To determine if abnormal corrosion has occurred in water-based fire protection systems, periodic flushing, system performance testing and inspections are conducted. ~~In addition to NFPA codes, portions of the water-based fire protection system (a) that are normally dry but periodically subject to flow (e.g., dry-pipe or preaction sprinkler system piping and valves) and (b) that cannot be drained or allow water to collect are subject to augmented testing and inspections.~~ Also, many of these systems are normally maintained at required operating pressure and monitored such that leakage resulting in loss of system pressure is immediately detected and corrective actions initiated.

- Revise Fire Water System Program procedures to inspect the ~~nozzles~~water distribution piping inside the charcoal filter units for ~~abnormal~~ corrosion when the charcoal is replaced. In the event the amount of corrosion exceeds normal surface corrosion, enter the condition into the corrective action program. (Refer to NFPA-25 (2011 Edition), Section~~s 13.4.3.2.2 and~~ 14.2)

- Revise Fire Water System Program procedures to inspect for and require replacement of sprinkler heads (nozzles) if they show signs of ~~abnormal~~ corrosion, ~~excessive~~ loading*, leakage, or if the glass bulb heat responsive element is found empty. (Refer to NFPA-25 (2011 Edition), Section 5.2.1.1.)

  * In lieu of replacing a loaded sprinkler head, sprinklers that are loaded with a coating of dust can be cleaned with compressed air or by vacuum provided that the equipment does not touch the sprinkler head.

- Revise Fire Water System Program procedures to inspect the accessible portions of the water distribution piping inside the charcoal filter units for corrosion when the charcoal is sampled. In the event the amount of corrosion exceeds normal surface corrosion, enter the condition into the corrective action program.

- Revise Fire Water System Program procedures to inspect the interior and exterior of the fire water storage tanks in accordance with NFPA 25 (2011 Edition), Sections 9.2.5.5, 9.2.6 and 9.2.7, with the exception of NFPA (2011 Edition) Sections 9.2.7.1 and 9.2.7.6. In lieu of testing specified in Section 9.2.7.1, alternate adhesion testing endorsed by Regulatory Guide (RG) 1.54 may be performed ~~perform holiday testing.~~ In lieu of testing specified in Section 9.2.7.6, perform ultrasonic thickness checks or mechanical measurements of any identified corroded areas at least once every five years.

- Revise Fire Water System Program procedures to determine the extent of coating defects on the interior of the fire water tanks by using one or more of the following methods when conditions such as cracking, peeling, blistering, delamination, rust or flaking are identified during visual examination.

  1. Lightly tapping and scraping the coating to determine the coating integrity.

2. Wet-sponge testing or dry film testing to identify holidays in the coating.
3. Adhesion testing in accordance with ASTM D3359, ASTM D4541, or equivalent testing endorsed by RG 1.54 at a minimum of three locations.
4. Ultrasonic testing where there is evidence of pitting or corrosion to determine if the tank thickness meets the minimum thickness criteria.

- Revise the Fire Water System Program procedures to ensure a fire water tank is not returned to service after identifying interior coating blistering, delamination or peeling unless there are only a few small intact blisters surrounded by coating bonded to the substrate as determined by a qualified coating inspector, or the following actions are performed:

  1) Any blistering in excess of a few small intact blisters, or blistering not completely surrounded by coating bonded to the substrate is removed,
  2) Any delaminated or peeled coating is removed,
  3) The exposed underlying coating is verified to be securely bonded to the substrate as determined by an adhesion test endorsed by RG 1.54 at a minimum of three locations,
  4) The outermost coating is feathered and the remaining outermost coating is determined to be securely bonded to the coating below via an adhesion test endorsed by RG 1.54 at a minimum of three locations adjacent to the defective area,
  5) Ultrasonic testing is performed where there is evidence of pitting or corrosion to ensure the tank meets minimum wall thickness requirements,
  6) An evaluation is performed to ensure downstream flow blockage is not a concern, and
  7) A follow-up inspection is scheduled to be performed within two years and every two years after that until the coating is repaired, replaced, or removed.

- Revise Fire Water System Program procedures to perform an internal inspection of wet fire water system piping conditions every five years, or after an extended shutdown of greater than one year, by opening a flushing connection at the end of one main and by removing a closed sprinkler toward the end of one branch line for the purpose of inspecting the interior for evidence of loss of material and the presence of foreign organic and inorganic material that could result in flow obstructions or blockage of sprinkler heads or nozzles. In the event there are multiple wet pipe systems in a structure, one third will be inspected every five years such that all systems will be inspected during each 15-year period. The procedures will include (1) guidance to perform an evaluation for MIC in the event tubercles or slime are identified, and (2) acceptance criteria that states "no abnormal debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged). Corrective actions will specify that any signs of abnormal corrosion or blockage will be removed and the condition will be entered into the corrective action program~~,~~. Inspection scope will be expanded to include all of the wet pipe sprinkler systems in that building and the source and extent of condition determined and corrected~~, and entered into the corrective action program~~. (Refer to NFPA-25 (2011 Edition), Section 14.2.)

A.2.1.33 Service Water Integrity Program

The Service Water Integrity Program is an existing program that relies on implementation of the recommendations of GL 89-13 to ensure that the effects of aging on the service water system are managed through the period of extended operation. The program includes component inspections for erosion, corrosion, and biofouling to verify the heat transfer capability of safety-related heat exchangers cooled by service water. Chemical treatment using biocides and sodium hypochlorite and periodic cleaning and flushing of infrequently used loops are methods used to control fouling within the heat exchangers and to manage loss of material in service water components. Scheduling of nonsafety-related piping examinations is determined by trending of examination results. Selection of large bore service water pipe points for volumetric inspection is based on piping configuration, results from previous inspections, consideration of follow-ups to previous repairs, and condition assessments when components are opened during preventive maintenance activities. Scope expansion for indications found by program inspections of nonsafety-related piping is based on engineering analysis, judgment and program experience. The factors that are considered include piping location, severity of use, piping materials, previous inspection results, and repair history.

A.3.1.33 Service Water Integrity Program

The Service Water Integrity Program is an existing program that relies on implementation of the recommendations of GL 89-13 to ensure that the effects of aging on the service water system are managed through the period of extended operation. The program includes component inspections for erosion, corrosion, and biofouling to verify the heat transfer capability of safety-related heat exchangers cooled by service water. Chemical treatment using biocides and chlorine and periodic cleaning and flushing of infrequently used loops are methods used to control fouling within the heat exchangers and to manage loss of material in service water components. Scheduling of nonsafety-related piping examinations is determined by trending of examination results. Selection of large bore service water pipe points for volumetric inspection is based on piping configuration, results from previous inspections, consideration of follow-ups to previous repairs, and condition assessments when components are opened during preventive maintenance activities. Scope expansion for indications found by program inspections of nonsafety-related piping is based on engineering analysis, judgment and program experience. The factors that are considered include piping location, severity of use, piping materials, previous inspection results, and repair history.

B.1.1 ABOVEGROUND STEEL TANKS PROGRAM

The Aboveground Steel Tanks Program will be enhanced to include the following tank inspection details[1].

Material	Environment	AERM	Inspection Technique[2]	Inspection Frequency
Inspections to identify degradation of inside surfaces of tank shell, roof[3], and bottom Inside Surface (IS), Outside Surface (OS)[4, 5]				
Steel	Raw water (city water)	Loss of material	Volumetric from OS[6] or visual from IS	Each 10-year period of the period of extended operation

6. At least 25 percent of the tank surface is inspected using a method capable of precisely determining wall thickness. The inspection method should be demonstrated capable of detecting both general and pitting corrosion.

B.1.14 FIRE WATER SYSTEM PROGRAM

The Fire Water System Program is an existing program that manages water-based fire protection systems consisting of sprinklers, nozzles, fittings, valves, hydrants, hose stations, fire pump casings, water storage tanks, standpipes, piping, and components that are tested in accordance with applicable National Fire Protection Association (NFPA) codes. Such testing assures functionality of systems. To determine if abnormal corrosion has occurred in water-based fire protection systems, periodic flushing, system performance testing, and inspections are conducted. ~~In addition to NFPA codes, portions of the water-based fire protection system (a) that are normally dry but periodically subject to flow (e.g., dry-pipe or preaction sprinkler system piping and valves) and (b) that cannot be drained or allow water to collect are subject to augmented testing and inspections.~~ Also, many of these systems are normally maintained at required operating pressure and monitored such that leakage resulting in loss of system pressure is immediately detected and corrective actions initiated.

Elements Affected	Exceptions
4. Detection of Aging Effects	5. During an inspection in accordance with NFPA 25 (2011 Edition), Sections 9.2.6.4 and 9.2.7.1 specify an evaluation of interior tank coatings in accordance with the adhesion test of ASTM D 3359,~~.~~ Standard Test Methods for Measuring Adhesion by Tape Test, generally referred to as the "cross-hatch test," when indications are identified in the fire water~~,~~ tank coating. ~~IPEC performs holiday testing. In addition,~~ IPEC performs ultrasonic thickness checks or mechanical measurements of any identified corroded areas at least once every five years. ~~IPEC does not apply the cross-hatch test.~~ Although coating degradation testing may consist of destructive adhesion testing as described in ASTM 3359, non-destructive adhesion testing is the preferred method.[5] 6. NFPA 25 (2011 Edition), Section 9.7.2.~~1~~6 specifies vacuum box testing of fire water tanks that are designed with a flat bottom. The IPEC fire water tanks were designed to have flat bottom. However, performing vacuum box testing to identify leakage may not be possible in the event the bottom of the tanks is uneven.[6]
4. Detection of Aging Effects	~~8. NFPA 25 (2011 Edition), Section 13.4.3.2.3 specifies performing preaction valve trip testing with the control valve fully open. IP2 does not perform the preaction valve with the control valve fully open for the electric tunnels.~~[8] ~~9~~8. NFPA 25 (2011 Edition), Section 14.2.1 specifies an internal inspection for blockage every five years of

Elements Affected	Exceptions
	normally dry fire water piping that may experience periodic wetting. IPEC does not perform these interior inspections of the dry piping downstream of the deluge valves for the transformers.[~~9~~8] ~~10~~9. NFPA 25 (2011 Edition), Section 5.3.1 requires an annual inspection of sprinkler heads for leakage. IPEC does not inspect open sprinkler heads for leakage.[~~10~~9]

5. The fire water tanks at IPEC have a capacity of 300,000 and 350,000 gallons with continuous monitoring through instrumentation with alarms in the control room. The adhesion testing suggested in NFPA 25 (2011 Edition), Section 9.2.7, Item #1 (ASTM D3359) is a destructive test that requires cutting an 'X' in the coating down to the substrate in a number of locations. According to ASTM D3359, this testing of coating adhesion is not a precise test of coating adhesion and it is not unexpected to get different test results from different personnel performing the same test. Different test results occur because the test depends on (1) the peel angle and rate, (2) subjective visual assessment of any coating removed, and (3) humidity and temperature. The repair of the coating adhesion test locations would require a specific humidity and temperature. For these reasons, the adhesion test is not considered a prudent inspection method and alternate methods such as that described in ASTM D4541 may be used.

6. The fire water tanks at IPEC have a capacity of 300,000 and 350,000 gallons with continuous monitoring through instrumentation with alarms in the control room. Jockey pumps provide makeup to compensate for leakage from the system. Leakage in excess of jockey pump makeup capacity would be obvious to the operating staff and would result in corrective actions to identify and repair the source of the leakage. Therefore, the vacuum box testing is not necessary to ensure the tanks remain capable of fulfilling their license renewal intended functions.

~~8. Performing trip testing of the preaction valves for the IPEC electrical tunnels with the control valve in a closed or throttled position limits the amount of water that enters the piping designed to be dry downstream of the preaction valve.~~

~~9~~8 The deluge systems for the transformers are full flow tested every refueling outage and any blockage would be identified during that testing.

~~10~~9 Leakage from an open sprinkler head indicates a leaking deluge or control valve. Such leakage is due to degradation of the active subcomponents of the valves which are not subject to aging management review for license renewal. The Fire Water System Aging Management Program is not appropriate for managing degradation of active subcomponents.

Attributes Affected	Enhancements
4. Detection of Aging Effects	Revise IP2 and IP3 Fire Water System Program procedures to inspect for and require replacement of sprinkler heads (nozzles) if they show signs of ~~abnormal~~ corrosion, ~~excessive~~ loading*, leakage, or if the glass bulb heat responsive element is found empty.

Attributes Affected	**Enhancements**
	(Refer to NFPA-25 (2011 Edition), Section 5.2.1.1.) * In lieu of replacing a loaded sprinkler head, sprinklers that are loaded with a coating of dust can be cleaned with compressed air or by vacuum provided that the equipment does not touch the sprinkler head.
4. Detection of Aging Effects	Revise IP2 and IP3 Fire Water System Program procedures to inspect the ~~nozzles~~ water distribution piping inside the charcoal filter units for ~~abnormal~~ corrosion when the charcoal is replaced. In the event the amount of corrosion exceeds normal surface corrosion, enter the condition into the corrective action program. (Refer to NFPA-25 (2011 Edition), Section~~s~~ ~~13.4.3.2.2 and~~ 14.2.)
4. Detection of Aging Effects	Revise IP2 and IP3 Fire Water System Program procedures to inspect the accessible portions of the water distribution piping inside the charcoal filter units for corrosion when the charcoal is sampled. In the event the amount of corrosion exceeds normal surface corrosion, enter the condition into the corrective action program.
4. Detection of Aging Effects	Revise Fire Water System Program procedures to inspect the interior and exterior of the fire water storage tanks in accordance with NFPA 25 (2011 Edition), Sections 9.2.5.5, 9.2.6 and 9.2.7, with the exception of NFPA (2011 Edition) Sections 9.2.7.1 and 9.2.7.6. In lieu of testing specified in Section 9.2.7.1, alternate adhesion testing endorsed by Regulatory Guide (RG) 1.54 may be performed ~~perform holiday testing.~~ In lieu of testing specified in Section 9.2.7.6, perform ultrasonic thickness checks or mechanical measurements of any identified corroded areas at least once every five years.
4. Detection of Aging Effects	Revise Fire Water System Program procedures for inspecting the interior of the fire water tanks to include the following testing to determine the condition of the coating on the interior of the fire water tanks when conditions such as cracking, peeling, blisters, delamination, rust, or flaking are identified during the visual examination in accordance with NFPA 25 (2011 Edition), Section 9.2.6.4. 1. Lightly tapping and scraping the coating to determine the coating integrity.

Attributes Affected	Enhancements
	2. Wet-sponge testing or dry film testing to identify holidays in the coating. 3. Adhesion testing in accordance with ASTM D 3359, ASTM D4541, or equivalent testing endorsed by RG 1.54 at a minimum of three locations. 4. Ultrasonic testing where there is evidence of pitting or corrosion to determine if the tank thickness meets the minimum thickness criteria.
4. Detection of Aging Effects	Revise the Fire Water System Program procedures to ensure a fire water tank is not returned to service after identifying interior coating blistering, delamination or peeling unless there are only a few small intact blisters surrounded by coating bonded to the substrate as determined by a qualified coating inspector, or the following actions are performed: 1) Any blistering in excess of a few small intact blisters, or blistering not completely surrounded by coating bonded to the substrate is removed, 2) Any delaminated or peeled coating is removed, 3) The exposed underlying coating is verified to be securely bonded to the substrate as determined by an adhesion test endorsed by RG 1.54 at a minimum of three locations, 4) The outermost coating is feathered and the remaining outermost coating is determined to be securely bonded to the coating below via an adhesion test endorsed by RG 1.54 at a minimum of three locations adjacent to the defective area, 5) Ultrasonic testing is performed where there is evidence of pitting or corrosion to ensure the tank meets minimum wall thickness requirements, 6) An evaluation is performed to ensure downstream flow blockage is not a concern, and 7) A follow-up inspection is scheduled to be performed within two years and every two years after that until the coating is repaired, replaced, or removed.
4. Detection of Aging Effects	Revise IP2 Fire Water System Program procedures to remove a sprinkler head at the end of a branch line and perform an air test to ensure there is no downstream flow blockage when performing the electric tunnel preaction valve testing prescribed in NFPA 25 (2011 Edition), Section 13.4.3.2.3.
4. Detection of Aging Effects	Revise IP2 and IP3 Fire Water System Program

Attributes Affected	**Enhancements**
	procedures to perform an internal inspection of wet fire water system piping conditions every five years, or after an extended shutdown of greater than one year, by opening a flushing connection at the end of one main and by removing a closed sprinkler toward the end of one branch line for the purpose of inspecting the interior for evidence of loss of material and the presence of foreign organic and inorganic material that could result in flow obstructions or blockage of sprinkler head or nozzles. In the event there are multiple wet pipe systems in a structure, one third will be inspected every five years such that all systems will be inspected during each 15-year period. The procedures will include (1) guidance to perform an evaluation for MIC in the event tubercles or slime are identified, and (2) acceptance criteria that states "no abnormal debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged.) Corrective actions will specify that any signs of abnormal corrosion or blockage will be removed and the condition will be entered into the corrective action program~~,~~. Inspection scope will be expanded to include all of the wet pipe sprinkler systems in that building and the source and extent of condition determined and corrected~~, and entered into the corrective action program~~. (Refer to NFPA-25 (2011 Edition), Section 14.2.)

B.1.34 Service Water Integrity

Program Description

The Service Water Integrity Program is an existing program that relies on implementation of the recommendations of GL 89-13 to ensure that the effects of aging on the service water system are managed through the period of extended operation. The program includes component inspections for erosion, corrosion, and biofouling to verify the heat transfer capability of safety-related heat exchangers cooled by service water. Chemical treatment using biocides and sodium hypochlorite and periodic cleaning and flushing of infrequently used loops are methods used to control fouling within the heat exchangers and to manage loss of material in service water components. Prioritization of internal examinations of SW piping is based on safety classification. Scheduling of nonsafety-related piping examinations is determined by trending of examination results. Selection of large bore service water pipe points for volumetric inspection is based on piping configuration, results from previous inspections, consideration of follow-ups to previous repairs, and condition assessments when components are opened during preventive maintenance activities. Scope expansion for indications found by program inspections of nonsafety-related piping is based on engineering analysis, judgment and program experience. The factors that are considered include piping location, severity of use, piping materials, previous inspection results, and repair history.

ATTACHMENT 3 TO NL-15-092

LICENSE RENEWAL APPLICATION

IPEC LIST OF REGULATORY COMMITMENTS

Rev. 27

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

List of Regulatory Commitments

Rev. 27

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: Complete	NL-07-039 NL-13-122	A.2.1.1 A.3.1.1 B.1.1
	Implement LRA Sections, A.2.1.1, A.3.1.1 and B.1.1, as shown in NL-14-147.	IP2 & IP3: December 31, 2019	NL-14-147	A.2.1.1 A.3.1.1 B.1.1
	Implement LRA Sections, A.2.1.1 and B.1.1, as shown in NL-15-092	IP2 & IP3: December 31, 2019	NL-15-092	A.2.1.1 B.1.1
2	Enhance the Bolting Integrity Program for IP2 and IP3 to clarify that actual yield strength is used in selecting materials for low susceptibility to SCC and clarify the prohibition on use of lubricants containing MoS_2 for bolting. The Bolting Integrity Program manages loss of preload and loss of material for all external bolting.	IP2: Complete IP3: Complete	NL-07-039 NL-07-153 NL-13-122	A.2.1.2 A.3.1.2 B.1.2 Audit Items 201, 241, 270

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
3	Implement the Buried Piping and Tanks Inspection Program for IP2 and IP3 as described in LRA Section B.1.6. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M34, Buried Piping and Tanks Inspection. Include in the Buried Piping and Tanks Inspection Program described in LRA Section B.1.6 a risk assessment of in-scope buried piping and tanks that includes consideration of the impacts of buried piping or tank leakage and of conditions affecting the risk for corrosion. Classify pipe segments and tanks as having a high, medium or low impact of leakage based on the safety class, the hazard posed by fluid contained in the piping and the impact of leakage on reliable plant operation. Determine corrosion risk through consideration of piping or tank material, soil resistivity, drainage, the presence of cathodic protection and the type of coating. Establish inspection priority and frequency for periodic inspections of the in-scope piping and tanks based on the results of the risk assessment. Perform inspections using inspection techniques with demonstrated effectiveness.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153 NL-09-106 NL-09-111 NL-11-101	A.2.1.5 A.3.1.5 B.1.6 Audit Item 173
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	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 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
	oil storage tanks, EDG fuel oil day tanks, SBO/Appendix R diesel generator fuel oil day tank, GT-1 gas turbine fuel oil storage tanks, and diesel fire pump fuel oil storage tank; IP3: EDG fuel oil day tanks, EDG fuel oil storage tanks, Appendix R fuel oil storage tank, and diesel fire pump fuel oil storage tank. Enhance the Diesel Fuel Monitoring Program to change the analysis for water and particulates to a quarterly frequency for the following tanks. IP2: GT-1 gas turbine fuel oil storage tanks and diesel fire pump fuel oil storage tank; IP3: Appendix R fuel oil day tank and diesel fire pump fuel oil storage tank. Enhance the Diesel Fuel Monitoring Program to specify acceptance criteria for thickness measurements of the fuel oil storage tanks within the scope of the program. Enhance the Diesel Fuel Monitoring Program to direct samples be taken and include direction to remove water when detected. Revise applicable procedures to direct sampling of the onsite portable fuel oil contents prior to transferring the contents to the storage tanks. Enhance the Diesel Fuel Monitoring Program to direct the addition of chemicals including biocide when the presence of biological activity is confirmed.			
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: Complete	NL-07-039 NL-13-122	A.2.1.10 A.3.1.10 B.1.11
	Implement LRA Sections A.2.1.10, A.3.1.10 and B.1.11, as shown in NL-14-147.	IP2 & IP3: December 31, 2019	NL-14-147	A.2.1.10 A.3.1.10 B.1.11

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
6	Enhance the Fatigue Monitoring Program for IP2 to monitor steady state cycles and feedwater cycles or perform an evaluation to determine monitoring is not required. Review the number of allowed events and resolve discrepancies between reference documents and monitoring procedures. Enhance the Fatigue Monitoring Program for IP3 to include all the transients identified. Assure all fatigue analysis transients are included with the lowest limiting numbers. Update the number of design transients accumulated to date.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153	A.2.1.11 A.3.1.11 B.1.12, Audit Item 164
7	Enhance the Fire Protection Program to inspect external surfaces of the IP3 RCP oil collection systems for loss of material each refueling cycle. Enhance the Fire Protection Program to explicitly state that the IP2 and IP3 diesel fire pump engine sub-systems (including the fuel supply line) shall be observed while the pump is running. Acceptance criteria will be revised to verify that the diesel engine does not exhibit signs of degradation while running; such as fuel oil, lube oil, coolant, or exhaust gas leakage. Enhance the Fire Protection Program to specify that the IP2 and IP3 diesel fire pump engine carbon steel exhaust components are inspected for evidence of corrosion and cracking at least once each operating cycle. Enhance the Fire Protection Program for IP3 to visually inspect the cable spreading room, 480V switchgear room, and EDG room CO_2 fire suppression system for signs of degradation, such as corrosion and mechanical damage at least once every six months.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122	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: Complete	NL-07-039 NL-13-122 NL-07-153 NL-08-014	A.2.1.13 A.3.1.13 B.1.14 Audit Items 105, 106
	Implement LRA Sections, A.2.1.13, A.3.1.13 and B.1.14, as shown in NL-14-147.	IP2 & IP3: December 31, 2019	NL-14-147	A.2.1.13 A.3.1.13 B.1.14
	Implement LRA Sections A.2.1.13, A.3.1.13 and B.1.14, as shown in NL-15-019	IP2 & IP3: December 31, 2019	NL-15-019	A.2.1.13 A.3.1.13 B.1.14
	<u>Implement LRA Sections A.2.1.13, A.3.1.13 and B.1.14, as shown in NL-15-092</u>	<u>IP2 & IP3: December 31, 2019</u>	<u>NL-15-092</u>	<u>A.2.1.13 A.3.1.13 B.1.14</u>

#	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: Complete IP3: December 12, 2015	NL-07-039 NL-13-122	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 indication of tube erosion, vibration wear, corrosion, pitting, fouling, or scaling.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153 NL-09-018	A.2.1.16 A.3.1.16 B.1.17, Audit Item 52
11	Deleted		NL-09-056 NL-11-101	

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
12	Enhance the Masonry Wall Program for IP2 and IP3 to specify that the IP1 intake structure is included in the program.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122	A.2.1.18 A.3.1.18 B.1.19
13	Enhance the Metal-Enclosed Bus Inspection Program for IP2 and IP3 to visually inspect the external surface of MEB enclosure assemblies for loss of material at least once every 10 years. The first inspection will occur prior to the period of extended operation and the acceptance criterion will be no significant loss of material. Enhance the Metal-Enclosed Bus Inspection Program to add acceptance criteria for MEB internal visual inspections to include the absence of indications of dust accumulation on the bus bar, on the insulators, and in the duct, in addition to the absence of indications of moisture intrusion into the duct. Enhance the Metal-Enclosed Bus Inspection Program for IP2 and IP3 to inspect bolted connections at least once every five years if performed visually or at least once every ten years using quantitative measurements such as thermography or contact resistance measurements. The first inspection will occur prior to the period of extended operation. The plant will process a change to applicable site procedure to remove the reference to "re-torquing" connections for phase bus maintenance and bolted connection maintenance.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153 NL-08-057 NL-13-077	A.2.1.19 A.3.1.19 B.1.20 Audit Items 124, 133, 519
14	Implement the Non-EQ Bolted Cable Connections Program for IP2 and IP3 as described in LRA Section B.1.22.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122	A.2.1.21 A.3.1.21 B.1.22

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
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: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153 NL-11-032 NL-11-096 NL-11-101	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: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 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: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 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 the oil analysis for other site diesel generators. Enhance the Oil Analysis Program for IP2 and IP3 to sample and analyze generator seal oil and turbine hydraulic control oil. Enhance the Oil Analysis Program for IP2 and IP3 to formalize preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria for all components included in the scope of this program. The program will specify corrective actions in the event acceptance criteria are not met. Enhance the Oil Analysis Program for IP2 and IP3 to formalize trending of preliminary oil screening results as well as data provided from independent laboratories.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 NL-11-101	A.2.1.25 A.3.1.25 B.1.26
19	Implement the One-Time Inspection Program for IP2 and IP3 as described in LRA Section B.1.27. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M32, One-Time Inspection.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 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: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 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: Complete IP3: December 12, 2015	NL-07-039 NL-13-122	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: Complete IP3: December 12, 2015	NL-07-039 NL-13-122	A.2.1.31 A.3.1.31 B.1.32
23	Implement the Selective Leaching Program for IP2 and IP3 as described in LRA Section B.1.33. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M33 Selective Leaching of Materials.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 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: Complete IP3: Complete	NL-07-039 NL-13-122	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) • nuclear service building (IP1) • primary water storage tank foundation (IP3) • refueling water storage tank foundation (IP3)	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153 NL-08-057 NL-13-077	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
	• security access and office building (IP3) • service water pipe chase (IP2/3) • service water valve pit (IP3) • superheater stack • transformer/switchyard support structures (IP2) • waste holdup tank pits (IP2/3) Enhance the Structures Monitoring Program for IP2 and IP3 to clarify that in addition to structural steel and concrete, the following commodities (including their anchorages) are inspected for each structure as applicable. • cable trays and supports • concrete portion of reactor vessel supports • conduits and supports • cranes, rails and girders • equipment pads and foundations • fire proofing (pyrocrete) • HVAC duct supports • jib cranes • manholes and duct banks • manways, hatches and hatch covers • monorails • new fuel storage racks • sumps Enhance the Structures Monitoring Program for IP2 and IP3 to inspect inaccessible concrete areas that are exposed by excavation for any reason. IP2 and IP3 will also inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspections of elastomers (seals, gaskets, seismic joint filler, and roof elastomers) to identify cracking and change in material properties and for inspection of aluminum vents and louvers to identify loss of material. Enhance the Structures Monitoring Program for IP2		NL-13-077	

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	and IP3 to perform an engineering evaluation of groundwater samples to assess aggressiveness of groundwater to concrete on a periodic basis (at least once every five years). IPEC will obtain samples from at least 5 wells that are representative of the ground water surrounding below-grade site structures and perform an engineering evaluation of the results from those samples for sulfates, pH and chlorides. Additionally, to assess potential indications of spent fuel pool leakage, IPEC will sample for tritium in groundwater wells in close proximity to the IP2 spent fuel pool at least once every 3 months. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspection of normally submerged concrete portions of the intake structures at least once every 5 years. Inspect the baffling/grating partition and support platform of the IP3 intake structure at least once every 5 years. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspection of the degraded areas of the water control structure once per 3 years rather than the normal frequency of once per 5 years during the PEO. Enhance the Structures Monitoring Program to include more detailed quantitative acceptance criteria for inspections of concrete structures in accordance with ACI 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures" prior to the period of extended operation.		NL-08-127 NL-11-032 NL-11-101	Audit Item 360 Audit Item 358
26	Implement the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.37. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122 NL-07-153	A.2.1.36 A.3.1.36 B.1.37 Audit item 173

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
27	Implement the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.38. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M13, Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153	A.2.1.37 A.3.1.37 B.1.38 Audit item 173
28	Enhance the Water Chemistry Control – Closed Cooling Water Program to maintain water chemistry of the IP2 SBO/Appendix R diesel generator cooling system per EPRI guidelines. Enhance the Water Chemistry Control – Closed Cooling Water Program to maintain the IP2 and IP3 security generator and fire protection diesel cooling water pH and glycol within limits specified by EPRI guidelines.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-08-057	A.2.1.39 A.3.1.39 B.1.40 Audit item 509
29	Enhance the Water Chemistry Control – Primary and Secondary Program for IP2 to test sulfates monthly in the RWST with a limit of <150 ppb.	IP2: Complete	NL-07-039 NL-13-122	A.2.1.40 B.1.41
30	For aging management of the reactor vessel internals, IPEC will (1) participate in the industry programs for investigating and managing aging effects 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: Complete IP3: Complete	NL-07-039 NL-13-122 NL-11-107	A.2.1.41 A.3.1.41
31	Additional P-T curves will be submitted as required per 10 CFR 50, Appendix G prior to the period of extended operation as part of the Reactor Vessel Surveillance Program.	IP2: Complete IP3: December 12, 2015	NL-07-039 NL-13-122	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: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-08-021 NL-10-082	A.2.2.2.3 A.3.2.2.3 4.3.3 Audit item 146
34	IP2 SBO / Appendix R diesel generator will be installed and operational by April 30, 2008. This committed change to the facility meets the requirements of 10 CFR 50.59(c)(1) and, therefore, a license amendment pursuant to 10 CFR 50.90 is not required.	Complete	NL-13-122 NL-07-078 NL-08-074 NL-11-101	2.1.1.3.5

#	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 period of extended operation, to assure liner degradation is not occurring in this area. Perform a one-time inspection of representative sample area of the IP3 containment steel liner at the juncture with the concrete floor slab, prior to entering the period of extended operation, to assure liner degradation is not occurring in this area. Any degradation will be evaluated for updating of the containment liner analyses as needed.	IP2: Complete IP3: December 12, 2015	NL-08-127 NL-13-122 NL-11-101 NL-09-018	Audit Item 27
36	Perform a one-time inspection and evaluation of a sample of potentially affected IP2 refueling cavity concrete prior to the period of extended operation. The sample will be obtained by core boring the refueling cavity wall in an area that is susceptible to exposure to borated water leakage. The inspection will include an assessment of embedded reinforcing steel. Additional core bore samples will be taken, if the leakage is not stopped, prior to the end of the first ten years of the period of extended operation. A sample of leakage fluid will be analyzed to determine the composition of the fluid. If additional core samples are taken prior to the end of the first ten years of the period of extended operation, a sample of leakage fluid will be analyzed.	IP2: Complete	NL-08-127 NL-11-101 NL-13-122 NL-09-056 NL-09-079	Audit Item 359
37	Enhance the Containment Inservice Inspection (CII-IWL) Program to include inspections of the containment using enhanced characterization of degradation (i.e., quantifying the dimensions of noted indications through the use of optical aids) during the period of extended operation. The enhancement includes obtaining critical dimensional data of degradation where possible through direct measurement or the use of scaling technologies for photographs, and the use of consistent vantage points for visual inspections.	IP2: Complete IP3: Complete	NL-08-127 NL-13-122	Audit Item 361

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
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: Complete IP3: December 12, 2015	NL-08-143 NL-13-122	4.2.1
39	Deleted		NL-09-079	
40	Evaluate plant specific and appropriate industry operating experience and incorporate lessons learned in establishing appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs. Documentation of the operating experience evaluated for each new program will be available on site for NRC review prior to the period of extended operation.	IP2: Complete IP3: December 12, 2015	NL-09-106 NL-13-122	B.1.6 B.1.22 B.1.23 B.1.24 B.1.25 B.1.27 B.1.28 B.1.33 B.1.37 B.1.38
41	IPEC will inspect steam generators for both units to assess the condition of the divider plate assembly. The examination technique used will be capable of detecting PWSCC in the steam generator divider plate assembly. The IP2 steam generator divider plate inspections will be completed within the first ten years of the period of extended operation (PEO). The IP3 steam generator divider plate inspections will be completed within the first refueling outage following the beginning of the PEO.	IP2: After the beginning of the PEO and prior to September 28, 2023 IP3: Prior to the end of the first refueling outage following the beginning of the PEO.	NL-11-032 NL-11-074 NL-11-090 NL-11-101	N/A

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
42	IPEC will develop a plan for each unit to address the potential for cracking of the primary to secondary pressure boundary due to PWSCC of tube-to-tubesheet welds using one of the following two options. Option 1 (Analysis) IPEC will perform an analytical evaluation of the steam generator tube-to-tubesheet welds in order to establish a technical basis for either determining that the tubesheet cladding and welds are not susceptible to PWSCC, or redefining the pressure boundary in which the tube-to-tubesheet weld is no longer included and, therefore, is not required for reactor coolant pressure boundary function. The redefinition of the reactor coolant pressure boundary must be approved by the NRC as a license amendment request. Option 2 (Inspection) IPEC will perform a one-time inspection of a representative number of tube-to-tubesheet welds in each steam generator to determine if PWSCC cracking is present. If weld cracking is identified: a. The condition will be resolved through repair or engineering evaluation to justify continued service, as appropriate, and b. An ongoing monitoring program will be established to perform routine tube-to-tubesheet weld inspections for the remaining life of the steam generators.	IP2: Prior to March 2024 IP3: Prior to the end of the first refueling outage following the beginning of the PEO. IP2: Between March 2020 and March 2024 IP3: Prior to the end of the first refueling outage following the beginning of the PEO.	NL-11-032 NL-11-074 NL-11-090 NL-11-096	N/A
43	IPEC will review design basis ASME Code Class 1 fatigue evaluations to determine whether the NUREG/CR-6260 locations that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting locations for the IP2 and IP3 configurations. If more limiting locations are identified, the most limiting location will be evaluated for the effects of the reactor coolant environment on fatigue usage. IPEC will use the NUREG/CR-6909 methodology in the evaluation of the limiting locations consisting of nickel alloy, if any.	IP2: Complete IP3: Prior to December 12, 2015	NL-11-032 NL-13-122 NL-11-101	4.3.3

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
44	IPEC will include written explanation and justification of any user intervention in future evaluations using the WESTEMS "Design CUF" module.	IP2: Complete IP3: Prior to December 12, 2015	NL-11-032 NL-11-101 NL-13-122	N/A
45	IPEC will not use the NB-3600 option of the WESTEMS program in future design calculations until the issues identified during the NRC review of the program have been resolved.	IP2: Complete IP3: Prior to December 12, 2015	NL-11-032 NL-11-101 NL-13-122	N/A
46	Include in the IP2 ISI Program that IPEC will perform twenty-five volumetric weld metal inspections of socket welds during each 10-year ISI interval scheduled as specified by IWB-2412 of the ASME Section XI Code during the period of extended operation. In lieu of volumetric examinations, destructive examinations may be performed, where one destructive examination may be substituted for two volumetric examinations.	IP2: Complete	NL-11-032 NL-11-074 NL-13-122	N/A
47	Deleted.		NL-14-093	N/A
48	Entergy will visually inspect IPEC underground piping within the scope of license renewal and subject to aging management review prior to the period of extended operation and then on a frequency of at least once every two years during the period of extended operation. This inspection frequency will be maintained unless the piping is subsequently coated in accordance with the preventive actions specified in NUREG-1801 Section XI.M41 as modified by LR-ISG-2011-03. Visual inspections will be supplemented with surface or volumetric non-destructive testing if indications of significant loss of material are observed. Consistent with revised NUREG-1801 Section XI.M41, such adverse indications will be entered into the plant corrective action program for evaluation of extent of condition and for determination of appropriate corrective actions (e.g., increased inspection frequency, repair, replacement).	IP2: Complete IP3: Prior to December 12, 2015	NL-12-174 NL-13-122	N/A

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
49	Recalculate each of the limiting CUFs provided in section 4.3 of the LRA for the reactor vessel internals to include the reactor coolant environment effects (F_{en}) as provided in the IPEC Fatigue Monitoring Program using NUREG/CR-5704 or NUREG/CR-6909. In accordance with the corrective actions specified in the Fatigue Monitoring Program, corrective actions include further CUF re-analysis, and/or repair or replacement of the affected components prior to the CUF_{en} reaching 1.0.	IP2: Complete IP3: Prior to December 12, 2015	NL-13-052 NL-13-122	A.2.2.2 A.3.2.2
50	Replace the IP2 split pins during the 2016 refueling outage (2R22).	IP2: Prior to completion of 2R22 IP3: N/A	NL-13-122 NL-14-067	A.2.1.41 B.1.42
51	Enhance the Service Water Integrity Program by implementing LRA Sections A.2.1.33, A.3.1.33 and B.1.34, as shown in NL-14-147.	IP2 & IP3: December 31, 2019	NL-14-147	A.2.1.33 A.3.1.33 B.1.34
52	Implement the Coating Integrity Program for IP2 and IP3 as described in LRA Section B.1.42, as shown in NL-15-019.	IP2 & IP3: December 31, 2024	NL-15-019	A.2.1.42 A.3.1.42 B.1.43