Entergy

Entergy Nuclear Northeast
Indian Point Energy Center
450 Broadway, GSB
P.O. Box 249
Buchanan, NY 10511-0249
Tel (914) 788-2055

Fred Dacimo
Vice President
License Renewal

NL-11-032

March 28, 2011

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

SUBJECT: Response to Request for Additional Information (RAI)
Aging Management Programs
Indian Point Nuclear Generating Unit Nos. 2 & 3
Docket Nos. 50-247 and 50-286
License Nos. DPR-26 and DPR-64

REFERENCE: 1. NRC Letter, "Request for Additional Information for the Review of the Indian Point Nuclear Generating Unit Numbers 2 and 3, License Renewal Application," dated February 10, 2011

Dear Sir or Madam:

Entergy Nuclear Operations, Inc is providing, in Attachment 1, the response to the referenced letter request for additional information (RAI). In addition, Attachment 1 includes a response to questions asked of other license renewal applicants regarding fatigue analysis software. Attachment 2 provides the latest list of regulatory commitments to include new commitments contained in this letter.

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

A128
NRR

I declare under penalty of perjury that the foregoing is true and correct. Executed on
March 28, 2011.

Sincerely,

FRD/cbr

Attachment: 1. Response to Request for Additional Information (RAI), Aging Management Programs

2. IPEC List of Regulatory Commitments (Rev. 13)

cc: Mr. William Dean, 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. John Boska, NRR Senior Project Manager
Mr. Paul Eddy, New York State Department of Public Service
NRC Resident Inspector's Office
Mr. Francis J. Murray, Jr., President and CEO NYSERDA

**ATTACHMENT 1 TO NL-11-032**

**LICENSE RENEWAL APPLICATION**
**RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION (RAI)**
**AGING MANAGEMENT PROGRAMS**

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

**INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3
LICENSE RENEWAL APPLICATION
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION (RAI)
AGING MANAGEMENT PROGRAMS**

**RAI 3.0.3.1.2-1**

Background

In light of Operating Experience (OE) that has occurred coincident with and after the staff evaluation of the Indian Point License Renewal Application (LRA) and issuance of the Safety Evaluation Report (SER), the staff is concerned about the continued susceptibility to failure of buried (i.e., piping in direct contact with soil) and/or underground piping (i.e., piping not in direct contact with soil, but located below grade in a vault, pipe chase, or other structure where it is exposed to air and where access is limited) that is within the scope of 10 CFR 54.4 and subject to aging management for license renewal. The staff reviewed the LRA, SER and a letter dated July 27, 2009 from the applicant addressing buried pipe program modifications as a result of recent site operating experience. Based on the review of these documents subsequent to the recent industry OE, the staff does not have enough information to evaluate how Indian Point is implementing changes to their program based on the industry experience.

Issue

1. The LRA and supplemental material did not contain enough specifics on the planned inspections for the staff to determine if the inspections would be adequate to manage the aging effect for all types/materials of in-scope buried pipes (e.g., safety/code class and potential to release materials detrimental to the environment (e.g., diesel fuel and radioisotopes that exceed Environmental Protection Agency (EPA) drinking water standards)).

2. The staff believes that buried coated steel piping is more susceptible to potential failure if it is not protected by a cathodic protection system unless soil resistivity is greater than 20,000 ohm-cm.

3. The LRA and supplemental material did not contain enough specifics for the staff to understand the general condition of the backfill used in the vicinity of buried in-scope piping.

4. In a letter dated July 27, 2009, the applicant stated that it will employ qualified inspection methods with demonstrated effectiveness for detection of aging effects during the period of extended operation. The staff acknowledges that where examining buried pipe from the exterior surface is not possible due to plant configuration (e.g., the piping is located underneath foundations) it is reasonable to substitute a volumetric examination from the interior of the pipe provided the surface is properly prepared. However, beyond ultrasonic techniques, the staff is not aware of another reliable volumetric inspection methodology that is suitable for inspecting buried in scope piping. This is particularly true, in light of industry experience, with guided wave ultrasonic technology.

5. Based on a review of the LRA and UFSAR, it is not clear to the staff what in-scope systems (if any) have underground piping or if such piping will receive inspections consistent with the program described in LRA AMP B.1.11 External Surfaces Monitoring Program.

6. LRA Sections A.2.1.5 and A.3.1.5 states that corrosion risk will be determined through consideration of material, soil resistivity, drainage, presence of cathodic protection and type of coating. Given that cathodic protection has not been installed for all buried in-scope piping, the staff lacks sufficient information to conclude that the applicant's evaluation of soil corrosivity will provide reasonable assurance that in-scope buried piping will meet its intended license renewal function(s). Specifically, the staff is concerned with the following:

   a. While the applicant stated that it will include consideration of soil resistivity and drainage, it did not state that other important soil parameters would be included such as, pH, chlorides, redox potential, sulfates and sulfides.
   b. The applicant did not state how often it will conduct testing of localized soil conditions, nor provide the specific locations relative to buried in-scope piping that is not cathodically protected.
   c. The applicant did not state how they would integrate the various soil parameters into an assessment of corrosivity of the soil, such as using "Assessment of Overall Soil Corrosivity to Steel,"[1] or AWWA C105[2].
   d. The applicant did not specifically state how localized soil data will be factored into increased inspections, including the specific increase in the number of committed inspections by material type and location.

Request

1. Respond to the following:

   a. Describe how many in-scope buried piping segments for each material, code/safety-related piping, and potential to release materials detrimental to the environment category will be inspected.

**Response for RAI 3.0.3.1.2-1 Part 1a**

**For the 10-year period prior to the PEO, the following table presents the planned inspections for buried piping subject to aging management review that is code/safety-related (Code/SR) or has the potential to release materials detrimental to the environment (hazmat). Inspections by material and category are indicated.**

| Material | Category | IP2 Inspections | IP3 Inspections |
|---|---|---|---|
| Carbon steel | Code/SR | 13 | 14 |
| Carbon steel | Hazmat | 13 | 5 |
| Stainless steel | Hazmat | N/A | 6 |

b. For the 45 planned inspections prior to the period of extended operation:

i. How many will consist of an excavated direct visual inspection of the external surfaces of the buried pipe?
ii. What length of piping will be excavated and have a direct visual inspection conducted?

**Response for RAI 3.0.3.1.2-1 Part 1b**

**The following table provides the number of planned direct visual inspections prior to the PEO. For planned direct visual inspections, future excavations will expose a minimum of 10 linear feet of pipe, for full circumferential inspections. Ten completed inspections have ranged from approximately five feet to more than ten feet averaging approximately eight linear feet.**

| Material | Category | IP2 Inspections | IP3 Inspections |
|---|---|---|---|
| Carbon steel | Code/SR | 9 | 8 |
| Carbon steel | Hazmat | 11 | 3 |
| Stainless steel | Hazmat | N/A | 3 |

c. Understanding that the total number of inspections performed will be informed by plant-specific and industry operating experience, what minimum number of inspections of buried in-scope piping is planned during the 40 – 50 and 50 – 60 year operating periods? When describing the minimum number of planned inspections, differentiate between material, code/safety-related piping, and potential to release materials detrimental to the environment category piping inspection quantities of buried in-scope piping.

**Response for RAI 3.0.3.1.2-1 Part 1c**

**IPEC will perform direct visual inspections during each 10-year period of the PEO in accordance with the following table. The table lists inspections for different materials, for code/safety-related piping, and for piping with the potential to release materials detrimental to the environment (indicated as hazmat.)**

| **Material** | **Category** | **IP2 Inspections** | **IP3 Inspections** |
|---|---|---|---|
| Carbon steel | Code/SR | 6 | 6 |
| Carbon steel | Hazmat | 8 | 8 |
| Stainless steel | Hazmat | N/A | 2 |

**If sample results indicate the soil is corrosive as described in the response to 2.c below, then the number of inspections for the carbon steel code/safety-related piping will be increased to eight and the number of inspections for the carbon steel hazmat piping will be increased to 12.**

d. What specific inspections will be performed for the IP3 security generator propane tank and at what frequency?

**Response for RAI 3.0.3.1.2-1 Part 1d**

**The nonsafety-related security generator system is credited for lighting during the response to fires in certain plant areas. Propane fuels the engine that drives the generator. Propane is non-toxic, non-caustic and will not create an environmental hazard if released as a liquid or vapor into water or soil. Monitoring the level of propane in the tank ensures the tank is capable of fulfilling its intended function. Consequently, only opportunistic inspections will be performed on the propane tank.**

2. Respond to the following:

   a. Confirm at IP2 that the service water system and at IP3 that the service water suction piping are the only in-scope steel piping systems currently protected by a cathodic protection (CP) system.

**Response for RAI 3.0.3.1.2-1 Part 2a**

**The IP2 service water lines near the river were originally provided with cathodic protection, but the rectifiers were subsequently removed. For IP2, the only in-scope steel piping cathodically protected is a portion of the city water piping in the area where they cross over the Algonquin gas pipelines.**

**At IP3, the service water suction is not piping and is not buried, but is the pump column in each respective intake bay. The pump columns were originally provided with cathodic protection. The cathodic protection, however, was subsequently removed. The pump columns have been replaced with materials with greater resistance to corrosion.**

**For IP3, the only in-scope buried piping cathodically protected is the city water line over the Algonquin gas pipelines.**

   b. For those systems that are protected by a CP system:
      i. Has annual NACE survey testing been conducted, and if so, for how many years?
      ii. Have the output of the beds been trended, and if so, what are the results of the trending?
      iii. What is the availability of the cathodic protection system?

**Response for RAI 3.0.3.1.2-1 Part 2b**

**A cathodic protection rectifier was installed in 2009 to protect the IP2 and IP3 city water lines near the Algonquin Gas pipelines.**

i. **Annual NACE surveys have been performed on the system since its installation in November 2009.**
ii. **The rectifier output has been steady. Final testing and adjustment of the system occurred in July 2010.**

iii. **The system has been in service since installation. It was out of service in July 2010 for one week. System availability since installation in November 2009 has been greater than 98%.**

c. For buried in-scope steel piping systems that are not cathodically protected:

i. Justify why this piping will continue to meet or exceed the minimum design wall thickness throughout the period of extended operation, assuming that no coatings are applied to the piping, or

ii. Justify why the number of the planned inspections of this piping is sufficient to reasonably assure that this piping will continue to meet or exceed the minimum design wall thickness throughout the period of extended operation.

**Response for RAI 3.0.3.1.2-1 Part 2c**

**The piping in question is coated which provides a significant barrier to corrosion. Inspections of excavated piping as discussed in the response to 3a below have found the coatings to be in good condition with no piping degradation. In addition, soil resistivity measurements as discussed in 3b below have shown the soil is non- aggressive. The number of planned inspections as discussed in 1a and the recent operating experience from site excavations provide reasonable assurance the piping will meet its license renewal intended functions during the PEO.**

**In addition, Entergy uses risk ranking to identify piping segments that are limiting (for example, closest to the water table) for direct visual inspection. Inspection results from these segments that show that the piping continues to maintain adequate wall thickness, provides reasonable assurance that similar piping in less limiting locations will maintain adequate wall thickness for the PEO.**

**To provide additional assurance that the piping will remain capable of performing its intended function, soil will be sampled prior to the PEO to confirm that the soil conditions are not aggressive. The number of inspections during the PEO will be based on the results the soil samples. The soil samples will be taken prior to the period of extended operation and at least once every 10 years thereafter to confirm the initial sample results. Soil samples will be taken at a minimum of two locations at least three feet below the surface near in-scope piping to obtain representative soil conditions for each system. The parameters monitored will include soil moisture, pH, chlorides, sulfates, and resistivity. American Water Works Association (AWWA) Standard C105 Appendix A will be used to determine corrosiveness of the soil in addition to soil resistivity. If the soil resistivity is < 20,000 ohm-cm or the soil scores higher than 10 points using AWWA C105, the number of inspections provided in the response to question 1.c will be increased to provide additional assurance that the piping can perform its design function during the PEO.**

**This approach provides reasonable assurance that piping will continue to meet its design function without cathodic protection.**

3. Respond to the following:

   a. Provide details on any further excavations conducted since July 2009 that provide insight on the extent of condition of the quality of the backfill in the vicinity of buried pipes.

**Response for RAI 3.0.3.1.2-1 Part 3a**

**Excavations since 2009:**

- **Oct, 2009 – 16-inch and 10-inch city water lines from the city water storage tank were inspected during a plant modification to install cathodic protection for city water lines near the Algonquin gas pipelines. Excavation and inspection covered approximately two 10-foot sections of 16-inch piping and approximately eight feet of the 10-inch piping. Inspections found good coating condition and good quality backfill.**

- **Nov. 2009 - 10-inch fire protection header. Inspection of approximately eight feet of piping found good condition of the coating and good quality of the backfill.**

  **In summary, visual inspections have not identified coating failures. Other than the condensate storage lines, visual observation of the backfill, has not identified rocks or foreign material with a reasonable potential to damage the piping external coating.**

   b. If there is no further information on the condition of the quality of backfill, justify why the planned inspections are adequate to detect potential degradation as a result of coating damage, particularly in steel buried pipe systems that are not protected by a CP system.

**Response for RAI 3.0.3.1.2-1 Part 3b**

**The results of the visual inspections performed to date indicate that the quality of the backfill in contact with the coatings is generally good (i.e. no large, sharp rock material in contact with the coating). In addition to those inspection results, data will be acquired from future excavations and direct inspections that will provide input to determine the need for additional inspections or adjusted inspection frequencies.**

4. Respond to the following:

   a. In absence of a qualified method, and until such time that one is demonstrated to be effective, what alternative inspection methods will Entergy employ when excavated direct visual examinations are not possible due to plant configuration.

**Response for RAI 3.0.3.1.2-1 Part 4a**

**In absence of a qualified method, and until such time that one is demonstrated to be effective, Entergy has no plans to employ alternate inspection methods.**

b. Justify why the methods identified in response to request 4a will be effective at providing reasonable assurance that the buried in-scope piping systems will meet their current licensing basis function.

**Response for RAI 3.0.3.1.2-1 Part 4b**

**Entergy has no plans to employ alternate inspection methods**

c. If a volumetric examination method is used, what percentage of interior axial length of the pipe will be inspected?

**Response for RAI 3.0.3.1.2-1 Part 4c**

**Entergy has no plans to employ alternate volumetric examination methods.**

5. For in-scope underground piping, respond to the following:

a. State what systems have underground piping and indicate the corresponding length of piping

**Response for RAI 3.0.3.1.2-1 Part 5a**

**Underground piping and tanks are below grade, but are contained within a tunnel or vault such that they are in contact with air and are located where access for inspection is restricted. In-scope SSCs that are subject to aging management review at IPEC include no underground piping or tanks.**

b. State how often and what quantity of underground piping for each system will be inspected by AMP, and indicate which AMP will be used.

**Response for RAI 3.0.3.1.2-1 Part 5b**

**Not applicable.**

6. Respond to the following for buried in-scope steel piping without cathodic protection:

   a. State what soil parameters will be included in the analysis of soil corrosivity beyond soil resistivity and drainage.
   b. State how often soil sampling will be conducted and in what locations.
   c. State how the various soil parameters will be integrated into an assessment of the corrosivity of the soil.
   d. State how localized soil conditions will be factored into increased inspections, including the specific increase in the number of committed inspections by material type and location.

**Response for RAI 3.0.3.1.2-1 Part 6a**

**Two commonly used methods for assessing soil corrosivity are (1) determination of soil resistivity alone, and (2) based on AWWA C105, which considers the following soil parameters: soil resistivity, pH, redox potential, sulfides, and moisture (drainage). Both of these measures will be used for determining soil corrosivity.**

**Response for RAI 3.0.3.1.2-1 Part 6b**

**Soil samples will be taken prior to the period of extended operation and at least once every 10 years thereafter to confirm the initial sample results. Soil samples will be taken at a minimum of two locations at least three feet below the surface near the in-scope piping to obtain representative soil conditions for each system.**

**Response for RAI 3.0.3.1.2-1 Part 6c**

**AWWA C105 soil corrosivity assessment utilizes a point system, using five (5) soil parameters: soil resistivity, pH, redox potential, sulfides, and moisture (drainage). Accordingly, soils scoring more than 10 points are considered corrosive. Based on soil resistivity alone, a resistivity > 20,000 ohm-cm is considered non-corrosive.**

**Response for RAI 3.0.3.1.2-1 Part 6d**

**Initial piping inspection priority and re-inspection interval will be based on the overall assessment of a piping segment's impact risk and corrosion risk, based on the best available data. Soil will be sampled prior to the PEO to confirm that the soil conditions are not aggressive. The number of inspections during the PEO will be based on the results of this soil survey. The soil samples will be taken prior to the period of extended operation and at least once every 10 years thereafter to confirm the initial sample results. If the soil resistivity is < 20,000 ohm-cm and the soil scores higher than 10 points using AWWA C105, the number of inspections will be increased as discussed in the response to question 1.c to ensure the piping can perform its design function during the PEO. The additional inspections will be in locations with aggressive soil condition.**

**RAI 3.0.3.1.6-1**

Background

NUREG-1801, Rev. 1, "Generic Aging Lessons Learned," (the GALL Report) addresses inaccessible medium voltage cables in Aging Management Program (AMP) XI.E3, "Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." The purpose of this program is to provide reasonable assurance that the intended functions of inaccessible medium voltage cables (2 kV to 35 kV), that are not subject to environmental qualification requirements of 10 CFR 50.49 and are exposed to adverse localized environments caused by moisture while energized, will be maintained consistent with the current licensing basis. The scope of the program applies to inaccessible (in conduits, cable trenches, cable troughs, duct banks, underground vaults or direct buried installations) medium-voltage cables within the scope of license renewal that are subject to significant moisture simultaneously with significant voltage.

The application of AMP XI.E3 to medium voltage cables was based on the operating experience available at the time Revision 1 of the GALL Report was developed. However, recently identified industry operating experience indicates that the presence of water or moisture can be a contributing factor in inaccessible power cables failures at lower service voltages (480 V to 2 kV). Applicable operating experience was identified in licensee responses to Generic Letter (GL) 2007-01, "Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients," which included failures of power cable operating at service voltages of less than 2 kV where water was considered a contributing factor.
Recently identified industry operating experience provided by NRC licensees in response to GL 2007-01 has shown: (a) that there is an increasing trend of cable failures with length in service beginning in the 6th through 10th years of operation and, (b) that moisture intrusion is the predominant factor contributing to cable failure. The staff has determined, based on the review of the cable failure distribution, that an annual inspection of manholes and a cable test frequency of at least every 6 years is a conservative approach to ensuring the operability of power cables and, therefore, should be considered.

In addition, recently identified industry operating experience has shown that some NRC licensees may experience cable manhole water intrusion events, such as flooding or heavy rain, that subjects cables within the scope of program for GALL Report XI.E3 to significant moisture. The staff has determined that event driven inspections of cable manholes, in addition to a 1 year periodic inspection frequency, is a conservative approach and, therefore, should be considered.

Issue

The staff has concluded, based on recently identified industry operating experience concerning the failure of inaccessible low voltage power cables (480 V to 2 kV) in the presence of significant moisture, that these cables can potentially experience age related degradation. The staff noted that the applicant's Inaccessible Medium-Voltage Cables Program does not address inaccessible low voltage power cables [400 V (nominally 480 V) to 2 kV inclusive]. In addition, more frequent cable test and cable manhole inspection frequencies (e.g., from 10 and two years to six and one year, respectively) should be evaluated to ensure that the Non-EQ Inaccessible Medium Voltage Cable program test and inspection frequencies reflect industry and plant-specific operating experience and that test and inspection frequencies may be increased based on future industry and plant-specific operating experience.

Request

Provide a summary of your evaluation of recently identified industry operating experience and any plant-specific operating experience concerning inaccessible low voltage power cable failures within the scope of license renewal (not subject to 10 CFR 50.49 environmental qualification requirements), and how this operating experience applies to the need for additional aging management activities at your plant for such cables.

**Response for RAI 3.0.3.1.6-1**

**As reported in the NRC's November 12, 2008 summary of licensee responses to GL 2007-01, the number of cable failures is a small percentage of the total number of cables in these categories for all nuclear plants.**

**Indian Point responded to GL 2007-01 on May 7, 2007 (ML071350410), and reported that Indian Point Unit 3 had experienced two cable failures, and that Unit 2 had experienced no failures based on the scope criteria set forth in GL 2007-01. Both Unit 3 failures involved low-voltage power cables, and were due to mechanical damage rather than the effects of aging. A search of plant-specific OE since the May 7, 2007 response to GL 2007-01 identified one Unit 2 failure and no Unit 3 failures of low or medium-voltage power cables that are in the scope of the maintenance rule or license renewal rule. Excavation activities associated with a plant modification damaged a Unit 2 13.8kV off-site power feeder cable causing the Unit 2 cable failure. The effects of aging did not cause the cable failure.**

**Indian Point is revising its Non-EQ Inaccessible Medium-Voltage Cable Program to include low-voltage power cables that may be exposed to significant moisture.**

1. Explain how Entergy will manage the effects of aging on inaccessible low voltage power cables within the scope of license renewal and subject to aging management review; with consideration of recently identified industry operating experience and any plant-specific operating experience. The discussion should include assessment of your aging management program description, program elements (i.e., Scope of Program, Parameters Monitored/Inspected, Detection of Aging Effects, and Corrective Actions), and FSAR summary description to demonstrate reasonable assurance that the intended functions of inaccessible low voltage power cables subject to adverse localized environments will be maintained consistent with the current licensing basis through the period of extended operation.

**Response for RAI 3.0.3.1.6-1 Part 1**

**Indian Point will include low-voltage power cables in the non-EQ inaccessible medium-voltage cable program, will increase cable testing and manhole inspedction frequency, and will provide for manhole inspections after events that could cause flooding of inaccessible cable raceways. The program will include provisions to increase cable testing and manhole inspection frequency based on the results of testing and inspections.**

**The following changes to LRA Sections A.2.1.22 and B.1.23 provide for the inclusion of low-voltage power cable in the Non-EQ Inaccessible Medium-Voltage Cable program.**

**A.2.1.22 Non-EQ Inaccessible Medium-Voltage Cable Program**

**The Non-EQ Inaccessible Medium-Voltage Cable Program is a new program that entails periodic and event-driven inspections for water collection in cable manholes, and periodic testing of cables. In scope medium-voltage cables (cables with operating voltage from 2kV to 35kV) and low-voltage power cables (400 V to 2 kV) exposed to significant moisture ~~and voltage~~ will be tested at least once every ~~ten~~ six years to provide an indication of the condition of the conductor insulation. Test frequencies are adjusted based on test results and operating experience. The program includes periodic inspections for water accumulation in manholes at least once every ~~two~~ year~~s~~ (annually). In addition to the periodic manhole inspections, inspection of event-driven occurrences, such as heavy rain or flooding will be performed. Inspection frequency will be increased as necessary based on evaluation of inspection results.**

**The Non-EQ Inaccessible Medium-Voltage Cable Program will be implemented prior to the period of extended operation. 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.**

**B.1.23 NON-EQ INACCESSIBLE MEDIUM-VOLTAGE CABLE**

**Program Description**

**The Non-EQ Inaccessible Medium-Voltage Cable Program is a new program that entails periodic inspections for water collection in cable manholes and periodic testing of cables. In scope medium-voltage cables (cables with operating voltage from 2kV to 35kV) and low-voltage power cables (400 V to 2 kV) exposed to significant moisture ~~and voltage~~ will be tested at least once every ~~ten~~ six years to provide an indication of the condition of the conductor insulation. Test frequencies will be adjusted based on test results and operating experience. The program includes inspections for water accumulation in manholes at least once every ~~two~~ year~~s~~ (annually). In addition to the periodic manhole inspections, inspection for event-driven occurrences, such as heavy rain or flooding will be performed. Inspection frequency will be increased as necessary based on evaluation of inspection results.**

**This program will be implemented prior to the period of extended operation.**

**Operating Experience**

**The Non-EQ Inaccessible Medium-Voltage Cable Program is a new program. Industry and plant-specific operating experience will be considered when implementing this program. Industry operating experience that forms the basis for the program is described in the operating experience element of the NUREG-1801 program description. IPEC plant-specific operating experience is not inconsistent with the operating experience in the NUREG-1801 program description.**

**The inspection frequency for manholes is based on plant-specific operating experience with cable wetting or submergence in manholes (i.e., the inspection is performed periodically based on water accumulation over time and events such as heavy rain or flooding).**

**The IPEC program is based on the program description in NUREG-1801, which in turn is based on industry operating experience. As such, operating experience provides assurance that the Non-EQ Inaccessible Medium-Voltage Cable Program will manage the effects of aging such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.**

**Conclusion**

**The Non-EQ Inaccessible Medium-Voltage Cable Program will be effective for managing aging effects since it will incorporate proven monitoring techniques and industry and plant-specific operating experience. The Non-EQ Inaccessible Medium-Voltage Cable Program assures that the effects of aging will be managed such that the applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.**

**Commitment 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~~ Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.**

2. Provide an evaluation showing that the proposed Non-EQ Inaccessible Medium-Voltage Cable program test and inspection frequencies, including event-driven inspections, incorporate recent industry and plant-specific operating experience for both inaccessible low and medium voltage cable.

**Response for RAI 3.0.3.1.6-1 Part 2**

**The Non-EQ Inaccessible Medium-Voltage Cable Program has been revised to include low-voltage inaccessible power cables. The cable test and manhole inspection frequencies have been increased in response to recent industry operating experience and license renewal correspondence. Provisions have been added to the program to increase the test and inspection frequencies if warranted by plant-specific test and inspection results or industry operating experience. Event-driven inspections have been added to the program based on recent industry license renewal correspondence. No recent adverse plant-specific operating experience has been identified that is inconsistent with industry operating experience. Therefore, the revised program incorporates recent operating experience associated with inaccessible low- and medium-voltage power cables.**

3. In Commitment 40, Entergy committed to evaluate plant-specific and industry operating experience prior to entering the period of extended operation. Explain how the proposed Inaccessible Medium Voltage Program will continue to ensure that future industry and plant-specific operating experience will be incorporated into the program such that inspection and test frequencies may be increased based on test and inspection results.

**Response for RAI 3.0.3.1.6-1 Part 3**

**The revised Non-EQ Inaccessible Medium Voltage Cable Program specifies that cable testing frequency and manhole inspection frequency will be adjusted as necessary based on the results of cable testing and manhole inspections. Indian Point will incorporate lessons learned from future industry and plant-specific operating experience, including plant-specific test and inspection results during implementation of the Non-EQ Inaccessible Medium Voltage Program.**

**RAI 3.0.3.1.10-1**

Background

By letter dated July 26, 2010, the applicant provided clarification of LRA Section B.1.28, "One Time Inspection – Small Bore Piping." The applicant stated that its Inservice Inspection (ISI) Program includes periodic volumetric examinations on ASME Class 1 small bore socket welds. The applicant further stated that the inspection volume is in accordance with guidelines established in MRP-146 which recommends examination of the base metal one-half inch beyond the toe of the weld. The applicant also cited recent plant-specific operating experience in which leakage was detected in a Class 1 socket weld, and referenced the related Licensee Event Report (LER#2010-004-00). The staff noted that the applicant did not provide information that supports its conclusion on the failure mechanism.

The staff noted that for IP2, the facility operating license (DPR-26) expires at midnight September 28, 2013, and for IP3, the facility operating license (DPR-64) expires at midnight December 12, 2015. The staff further noted that both IP2 and IP3 will be in their 4th ISI interval upon entering the period of extended operation.

Issue

The staff noted that the inspections performed by its Inservice Inspection Program for ASME Class 1 small bore socket welds only include the base metal, one-half inch beyond the toe of the weld. It is not clear to the staff how an inspection of the base metal, one-half inch beyond the toe of the weld, is capable of detecting cracking in the ASME Class 1 small bore socket weld metal.

Request

1. Explain how Entergy will manage aging (i.e., cracking) in the weld metal of ASME Code Class 1 small bore socket welds.

**Response for RAI 3.0.3.1.10-1 Part 1**

**IPEC will continue to perform visual examination (VT-2) as is required by ASME Code Case N-578, to manage the effects of aging on the ASME Class 1 small-bore socket welds for both units. In addition, IPEC will implement the One-Time Inspection - Small Bore Piping Program for IP3 and for butt welds on IP2.**

**For butt welds, IP2 will implement the One-Time Inspection - of ASME Code Class 1 Small Bore Piping Program, which manages cracking due to aging effects. The program will include volumetric examinations of small-bore piping butt weld metal on locations selected by the ISI Program using risk-informed methods to detect potential indications of cracking due to thermal fatigue and stress corrosion. For IP2, IPEC will perform volumetric examination of the weld metal of ten socket welds in 2012 and of at least ten socket welds during each 10-year period of the period of extended operation. These inspections will be included in the IP2 ISI Program.**

**IP3 has performed volumetric inspections on 25 small-bore piping welds, 21 of which were socket welds. Inspections on 18 of the welds inspected the root of the socket weld metal. The remaining three welds were inspected in accordance with MRP-146 (the base metal ½ inch from the weld). Sixteen (16) inspections had no recordable indications. Two socket welds had recordable indications and were cut out and destructively tested by EPRI. Metallographic evaluation determined that the recordable indications noted during the NDE inspections were root anomalies due to lack of fusion (LOF) during the welding process and were not part of the effective throat of the welds.**

2. Clarify if the inspection volume selected for the proposed volumetric examinations of ASME Class 1 small bore butt welds, performed by the One Time Inspection – Small Bore Piping Program, includes the weld metal. If it does not include the weld metal, justify that the inspection volume is sufficient and capable of detecting cracking in the ASME Code Class 1 small bore butt weld metal.

**Response for RAI 3.0.3.1.10-1 Part 2**

**The inspection volume selected for the proposed volumetric examination of ASME Class 1 small bore butt welds, performed under the One Time Inspection – Small Bore Piping Program, includes the weld metal. The inspection volume of the completed volumetric examinations of ASME Class 1 small bore butt welds, credited for the One Time Inspection – Small Bore Piping Program, included the weld metal.**

3. Based on the operating experience at Indian Point, justify that an aging management program that performs periodic volumetric inspections of the weld metal for ASME Code Class 1 small bore socket and butt welds is not necessary. In lieu of this justification provide an aging management program that includes periodic volumetric inspections to manage cracking in small-bore piping and the associated weld metal (socket weld metal and butt weld metal).

**Response for RAI 3.0.3.1.10-1 Part 3**

**The operating experience at IPEC indicates no Class 1 small bore socket weld or butt weld failures due to stress corrosion, cyclical loading (thermal, mechanical, and vibration fatigue), or thermal stratification and thermal turbulence. A review of operating experience at IP3 identified no leaks from small bore Class 1 piping socket welds. In approximately 38 years of operation, IP2 has experienced five leaks from small bore Class 1 socket welds, but cracking has never been identified as the cause. Rounded or pin hole defects caused three leaks, including the May 2010 leak, and mechanical damage caused a fourth. No cause was determined for the fifth leak which occurred in 1980, over 30 years ago. Nevertheless, IPEC performs periodic volumetric inspections of ASME Code Class 1 small bore socket welds. Ongoing inspections under the IPEC Inservice Inspection Program include periodic volumetric inspections of small bore piping welds on both units as determined by risk-informed selection criteria in the program. IPEC will volumetrically inspect the weld metal of at least ten socket welds in 2012 and at least ten socket welds during each 10-year period of the period of extended operation.**

4. Whether a one-time inspection program or periodic inspection program is selected, clarify the implementation schedule of the inspections for ASME Code Class 1 small-bore piping including the associated welds (socket welds and butt welds).

**Response for RAI 3.0.3.1.10-1 Part 4**

**For IP2, the schedule for ASME Class 1 small-bore piping inspections is contained in the IP2 ISI Program. In 2006, two butt welds were inspected. In 2010, three butt welds were inspected. Ten small-bore piping socket welds will be inspected in 2012 and one butt weld will be inspected prior to the period of extended operation. These future inspections will include the weld metal. In addition to the ten socket weld inspections in 2012, IPEC will perform volumetric weld metal inspections of ten socket welds during each 10-year period of the period of extended operation.**

**For IP3, One-Time Inspections have been completed. The associated inspections were completed from 2003 through 2007. In 2003, three welds were inspected; two socket welds and one butt weld. In 2005, 18 welds were inspected; 16 socket welds and two butt welds. In 2007, four welds were inspected; three socket welds and one butt weld. Thus, the total numbers of welds inspected was 21 socket welds and four butt welds. Eighteen of the socket weld inspections were volumetric inspections of the weld metal, two of which underwent subsequent destructive examinations. Because more information can be obtained from a destructive examination than from a nondestructive examination, each weld destructively examined is considered equivalent to two welds volumetrically examined. Counting the destructive examinations as two each, the number of volumetric socket weld inspections is 20 welds, which represents 6% of the population of 333 Class 1 small-bore piping socket welds at IP3. The four butt weld inspections, which inspected the weld metal, constitute 4.1% of the population of 96 butt welds.**

**RAI 3.0.3.1.10-2**

Background

SRP-LR Section A.1.2.3.4 states that when sampling is used a basis should be provided for the inspection population and sample size.
The "monitoring and trending" program element of GALL AMP XI.M35 recommends that the volumetric inspection should be performed at a sufficient number of locations to assure an adequate sample. Furthermore, this number, or sample size, will be based on susceptibility, inspectability, dose considerations,

operating experience, and limiting locations of the total population of ASME Code Class 1 small bore piping locations.
Issue

The staff noted that the applicant did not provide its basis for the sample size that it selected. Specifically, the weld populations and the sample size were not provided to the staff, therefore it is not clear to the staff what percentage of ASME Code Class 1 welds, both full penetration welds and socket welds, will be inspected. It is also not clear to the staff if a sufficient number of locations will be selected to ensure an adequate sample.

Request

Provide the total populations of ASME Code Class 1 small bore butt welds and socket welds at Indian Point for each unit. Justify that the number of samples, for both butt welds and socket welds, is sufficient to ensure that an adequate sample is selected for inspections to be performed.

**Response for RAI 3.0.3.1.10-2**

**There are 433 small bore socket welds and 195 small bore butt welds at IP2. There are 333 small bore socket welds and 96 small bore butt welds at IP3.**

**Of the 195 small bore butt welds on IP2, 5 butt welds have been inspected. All five weld inspections included the weld metal. In addition one butt weld (including the weld metal) will be inspected in 2012, thereby yielding a total sample size of 3%. Of the 333 small bore socket welds on IP3, 21 welds have been inspected. Of those 21 weld inspections, 18 inspections included the weld metal, two of which underwent subsequent destructive examinations. Counting the destructive examinations as two each, the total volumetric socket weld inspections is 20 welds, which represents 6% of the population of 333 Class 1 small-bore piping socket welds at IP3. Of the 96 small bore butt welds, four welds, or 4.1% of butt welds, have been inspected. All four weld inspections included the weld metal. Since IPEC has had no failures of small bore piping welds due to cracking resulting from stress corrosion, cyclical loading (thermal, mechanical, and vibration fatigue), or thermal stratification and thermal turbulence, the numbers of inspections constitute an adequate sample of the small bore weld populations.**

**Of the 433 small bore socket welds on IP2, 10 welds will be inspected (including the weld metal) in 2012 and 10 welds will be inspected during each 10-year period of the period of extended operation.**

**Commitment #46**
**Include in the IP2 ISI Program volumetric weld metal inspections of ten socket welds in 2012 and of at least ten socket welds during each 10-year period of the period of extended operation.**

**RAI 3.0.3.2.10-1**

Background

NRC staff has determined that masonry walls that are within the scope of license renewal should be visually examined at least every five years, with provisions for more frequent inspections in areas where significant loss of material or cracking is observed.
Issue

The LRA did not discuss the inspection interval for in scope masonry walls.

Request

Provide the inspection interval for in-scope masonry walls. If the interval exceeds five years, clearly explain why and how the interval will ensure that there is no loss of intended function between inspections.

**Response for RAI 3.0.3.2.10-1**

**The inspection interval for masonry walls within the scope of license renewal is every five years.**

**RAI 3.0.3.2.15-1**

Background

NRC staff has determined that adequate acceptance criteria for the Structures Monitoring Program should include quantitative limits for characterizing degradation. Chapter 5 of ACI 349.3R provides acceptable criteria for concrete structures. If the acceptance criteria in ACI 349.3R are not used, the plant-specific criteria should be described and a technical basis for deviation from ACI 349.3R should be provided.

Issue

The LRA did not clearly identify quantitative acceptance criteria for the Structures Monitoring Program inspections.

Request

1. Provide the quantitative acceptance criteria for the Structures Monitoring Program. If the criteria deviate from those discussed in ACI 349.3R, provide technical justification for the differences.

**Response for RAI 3.0.3.2.15-1 Part 1**

**For concrete structures, the Structures Monitoring Program (SMP) has a responsible engineer with the appropriate education and experience to identify and evaluate existing conditions using the appropriate industry standards for concrete structures, including ACI standards. Prior to the period of extended operation (PEO), Entergy will enhance the SMP to include more detailed quantitative acceptance criteria of ACI 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures" for concrete structures.**

**Commitment**
**Entergy is revising the following commitment (Commitment 25) for the Structures Monitoring Program for implementation prior to 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".**

2. If quantitative acceptance criteria will be added to the program as an enhancement, state whether Entergy plans to conduct an inspection with the quantitative acceptance criteria prior to the period of extended operation. If there are no plans to conduct an inspection with quantitative acceptance criteria prior to entering the period of extended operation, explain how Entergy plans to monitor and trend data.

**Response for RAI 3.0.3.2.15-1 Part 2**

**Program procedures specify that the inspection engineer be a degreed engineer or registered professional engineer, knowledgeable or trained in the design, evaluation, and performance requirements of structures, with at least 5 years structural design/analysis/field evaluation experience. Using applicable industry codes and standards, the responsible engineer has adequate training and education to determine the acceptability of identified conditions using appropriate references, which may include ACI 349.3R.**

**While all the detailed quantitative acceptance criteria of ACI 349.3R are not in the existing SMP procedures, the knowledge and experience of the qualified inspection engineers performing regularly scheduled inspections provides reasonable assurance of continued functionality of the concrete structures at IPEC. The enhanced inspection criteria from ACI 349.9-3R will be adopted prior to the PEO and will be applied during regularly scheduled inspections.**

**The enhancement described in part 1 (above) to include more detailed acceptance criteria of ACI 349.3R does not affect ongoing monitoring and trending of data collected during the inspections. Although the acceptance criteria of ACI 349.3R are not explicitly identified in inspection procedures, qualified inspection personnel have a working knowledge of those criteria. Based on their knowledge and experience, inspectors identify and record degradation outside the acceptance criteria of ACI 349.3R discovered during the inspections so that future monitoring can determine a trend. The documentation includes critical measurements, i.e., crack width, length, depth, or area and depth of spall, so that future inspectors can determine the degree of change, if any. Prior to performing inspections, inspection engineers perform a thorough review of previous inspection reports to identify existing deficiencies. Photos, checklists, notes, etc. are used to determine if further deterioration has occurred. This process for monitoring and trending inspection data will continue during the period of extended operations.**

**RAI 3.1.2.2.13-1**

Background

SRP-LR Section 3.1.2.2.13 identifies that cracking due to primary water stress corrosion cracking (PWSCC) could occur in PWR components made of nickel alloy and steel with nickel alloy cladding, including reactor coolant pressure boundary components and penetrations inside the RCS such as pressurizer heater sheathes and sleeves, nozzles, and other internal components. GALL Report Volume 2 Item IV.D1-06 recommends Chapter XI.M2, "Water Chemistry," for PWR primary water to manage the aging effect of cracking in the nickel alloy steam generator (SG) divider plate exposed to reactor coolant.

LRA Table 3.1.1, item 3.1.1-81, credits the Water Chemistry Control – Primary and Secondary Program to manage cracking due to primary stress corrosion cracking in nickel-alloy steam generator primary channel head divider plate exposed to reactor coolant in the steam generators, and LRA Table 3.1.1, Item 82, indicates that the SG primary side divider plates are composed of nickel alloy.

Unit 2 FSAR Section 4.2.2.3 and Table 4.2-1 describe the construction materials for the replacement Model 44F steam generators. The staff noted that there is no information about the construction materials of the divider plate assembly for the Unit 2 steam generators.

Unit 3 FSAR Section 4.2.2 and Table 4.2-1 describe the construction materials for the replacement Model 44F steam generators. The staff noted that there is no information about the construction materials of the divider plate assembly for the Unit 3 steam generators.

Issue

In some foreign steam generators with a similar design to that of Indian Point Units 2 and 3 steam generators, extensive cracking due to PWSCC has been identified in SG divider plate assemblies made with Alloy 600, even with proper primary water chemistry. Specifically, cracks have been detected in the stub runner, very close to the tubesheet/stub runner weld and with depths of almost a third of the divider plate thickness. Therefore, the staff noted that the Water Chemistry Control – Primary and Secondary Program may not be effective in managing the aging effect of cracking due to PWSCC in SG divider plate assemblies.

Although these SG divider plate assembly cracks may not have a significant safety impact in and of themselves, such cracks could affect adjacent items that are part of the reactor coolant pressure boundary, such as the tubesheet and the channel head, if they propagate to the boundary with these items. For the tubesheet, PWSCC cracks in the divider plate could propagate to the tubesheet cladding with possible consequences to the integrity of the tube-to-tubesheet welds. For the channel head, the PWSCC cracks in the divider plate could propagate to the SG triple point and potentially affect the pressure boundary of the SG channel head.

Request

1. Discuss the materials of construction of the Units 2 and 3 SG divider plate assemblies, including the welds within these assemblies and to the channel head and to the tubesheet.

**Response for RAI 3.1.2.2.13-1 Part 1**

**At IP2 and IP3 the divider plates are Inconel 600 (ASME-SB-168). It is conservatively assumed that the weld materials are the associated Alloy 600 weld materials.**

2. If any constitutive/weld material of the SG divider plate assemblies is susceptible to cracking (e.g., Alloy 600 or the associated Alloy 600 weld materials), explain how Entergy plans to manage PWSCC of the SG divider plate assemblies to prevent the propagation of cracks into other items that are part of the RCPB, whereby it challenges the integrity of the adjacent items.

**Response for RAI 3.1.2.2.13-1 Part 2**

**At IP2 the original Westinghouse Model 44 steam generators were replaced with Model 44F steam generators in 2000. At IP3 the original Westinghouse Model 44 steam generators were replaced with Model 44F steam generators in 1989.**

**The Electric Power Research Institute (EPRI) has extensively evaluated the foreign operating experience with divider plate cracking in their reports dated June 2007, November 2008, and December 2009, and concluded that a cracked divider plate in a Westinghouse Model F SG is not a safety concern, and does not affect the design of the adjacent pressure boundary components.**

**The industry plans are to study the potential for divider plate crack growth and develop a resolution to the concern through the EPRI Steam Generator Management Program (SGMP) Engineering and Regulatory Technical Advisory Group. This industry-lead effort is expected to begin in 2011 and be completed within two years.**

**Recognizing that the EPRI SGMP resolution of this issue is under development, Entergy will inspect all IPEC steam generators 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 welds. The steam generator divider plate inspections will be completed within the first ten years of the PEO. (Commitment 41)**

**RAI 3.1.2.2.16-1**

Background

SRP-LR Section 3.1.2.2.16 identifies that cracking due to primary water stress corrosion cracking (PWSCC) could occur on the primary coolant side of PWR steel steam generator (SG) tube-to-tube sheet welds made or clad with nickel alloy. The GALL Report recommends ASME Section XI ISI and control of water chemistry to manage this aging effect and recommends no further aging management review for PWSCC of nickel alloy if the applicant complies with applicable NRC Orders and provides a commitment in the FSAR supplement to implement applicable (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines. In GALL Report Revision 1, Volume 2, this aging effect is addressed in item IV.D2-4, applicable only to once-through SGs, but not to recirculating SGs.

The staff noted that ASME Code Section XI does not require any inspection of the tube-to-tubesheet welds. In addition, there are no NRC Orders or bulletins requiring examination of this weld. However, the staff's concern is that, if the tubesheet cladding is Alloy 600 or the associated Alloy 600 weld materials, the tube-to-tubesheet weld region may have insufficient Chromium content to prevent initiation of PWSCC. Similarly, this concern applies to SG tubes made from Alloy 690TT. Consequently, such a PWSCC crack initiated in this region, close to a tube, could propagate into/through the weld, causing a failure of the weld and of the reactor coolant pressure boundary, for both recirculating and once-through steam generators.

In LRA Table 3.1.1, item 3.1.1-35, the applicant stated that the corresponding GALL Report line applies to once-through steam generators and was used as a comparison for the steam generator tubesheets. The applicant further stated that for the steel with nickel alloy clad steam generator tubesheets, cracking is managed by the Water Chemistry Control – Primary and Secondary and Steam Generator Integrity Programs. In LRA Section 2.3.1.4, the applicant described that the Unit 2 replacement Westinghouse Model 44 steam generator tubes are fabricated from Alloy 600TT and the Unit 3 replacement Westinghouse Model 44 steam generator tubes are fabricated from Alloy 690TT. The applicant also described that the tubesheet surfaces in contact with reactor coolant are clad with Inconel, and the tube-to-tube sheet joints are welded.

Issue
Unless the NRC has approved a redefinition of the pressure boundary in which the autogenous tube-to-tubesheet weld is no longer included, or the tubesheet cladding and welds are not susceptible to PWSCC, the staff considers that the effectiveness of the primary water chemistry program should be verified to ensure PWSCC cracking is not occurring. Moreover, it is not clear to the staff how the Steam Generator Integrity Program is able to manage PWSCC of the tubesheet cladding, including the tube-to-tubesheet welds.

Request

1a. For Unit 2 SGs, clarify whether the tube-to-tubesheet welds are included in the reactor coolant pressure boundary or alternate repair criteria have been permanently approved.

**Response for RAI 3.1.2.2.16-1 Part 1a**

**At IP2 the tube to tubesheet welds are included in the RCS pressure boundary. IP2 does not employ any tubesheet region alternate repair criterion.**

1b. If the SGs do not have permanently approved alternate repair criteria, justify how your Steam Generator Integrity Program is capable to manage PWSCC in tube-to-tubesheet welds, or provide a plant-specific AMP that will complement the primary water chemistry program, in order to verify the effectiveness of the primary water chemistry program and ensure that cracking due to PWSCC is not occurring in tube-to-tubesheet welds.

**Response for RAI 3.1.2.2.16-1 Part 1b**

**IP2 will address the potential failure of the steam generator reactor coolant pressure boundary due to PWSCC cracking of tube-to-tubesheet welds via one of two options, an analysis or an inspection. (Commitment 42)**

**Analysis Option:**

**IP2 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 to exclude the tube-to-tubesheet weld, and therefore the weld will not be required for the reactor coolant pressure boundary function. The redefinition of the reactor coolant pressure boundary will be submitted as part of a license amendment request requiring approval from the NRC. An approved analytical evaluation would obviate the need to develop a plant-specific AMP to verify effectiveness of the Water Chemistry Control – Primary and Secondary program.**

**Inspection Option:**

**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 replaced its steam generators in 2000. The tube-to-tubesheet welds have been in service approximately eleven years. Considering this limited service time, if Option 1 is not implemented, IP2 will implement Option 2 that includes tube-to-tubesheet weld inspections for PWSCC. These inspections will be performed between March 2020 and March 2024 such that the steam generators will have been in service between 20 and 24 years.**

**In 2R17 (2006), 166 tubes were inspected to the tube end with a rotating pancake coil (RPC) probe. No degradation was detected.**

2. For Unit 3 SGs tube-to-tubesheet welds, justify how your Steam Generator Integrity Program is capable to manage PWSCC in tube-to-tubesheet welds, or provide either a plant-specific AMP that will complement the primary water chemistry program, in order to verify the effectiveness of the primary water chemistry program and ensure that cracking due to PWSCC is not occurring in tube-to-tubesheet welds, or a rationale for why such a program is not needed.

**Response for RAI 3.1.2.2.16-1 Part 2**

**IP3 will address the potential failure of the steam generator reactor coolant pressure boundary due to PWSCC cracking of tube-to-tubesheet welds via one of two options, an analysis or an inspection. (Commitment 42)**

**Analysis Option:**

**IP3 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 to exclude the tube-to-tubesheet weld, and therefore the weld will not be required for the reactor coolant pressure boundary function. The redefinition of the reactor coolant pressure boundary will be submitted as part of a license amendment request requiring approval from the NRC. An approved analytical evaluation would obviate the need to develop a plant-specific AMP to verify effectiveness of the Water Chemistry Control – Primary and Secondary program.**

**Inspection Option:**

**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. This one-time inspection would verify the effectiveness of the water chemistry AMP. 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.**

**IP3 replaced its steam generators in 1989. The tube-to-tubesheet welds have been in service approximately twenty two years. If Option 1 is not implemented, IP3 will implement Option 2 that includes tube-to-tubesheet weld inspections for PWSCC. For IP3 these inspections will be performed within the first 2 refueling outages following the period of extended operation.**

**RAI RCS-3**

Background

In LRA Section 4.3.3 and Commitment 33 (as amended by the letter dated January 22, 2008) the applicant discussed the methodology used to determine the locations that required environmentally-assisted fatigue analyses consistent with NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components." The staff recognized that, in LRA Tables 4.3-13 and 4.3-14, there are eight plant-specific locations listed based on the six generic components identified in NUREG/CR-6260. The applicant also discussed in LRA Tables 4.3-13 and 4.3-14 that the surge line nozzle in the RCS piping is bounded by the surge line piping to safe end weld at the pressurizer nozzle. LRA Section 4.3.3 and Commitment 33 were amended as follow:

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, IPEC 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.

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.
More plant-specific limiting locations with a valid CUF may be evaluated. In particular, the pressurizer lower shell will be reviewed to ensure the surge nozzle remains the limiting component.

Representative CUF values from other plants, adjusted to or enveloping the IPEC plant-specific external loads may be used if demonstrated applicable to IPEC.

An analysis using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case) may be performed to determine a valid CUF.

Issue

GALL AMP X.M1 states the impact of the reactor coolant environment on a sample of critical components should include the locations identified in NUREG/CR-6260, as a minimum, and that additional locations may be needed. The staff identified two concerns regarding the applicant's environmentally-assisted fatigue analyses. First, item (1) of above LRA section and Commitment 33 indicated that more limiting plant-specific locations may be evaluated. However, it is only one of the *options* that may be taken. Furthermore, the limiting locations *may* be added and the staff is concerned whether the applicant is committed to verify that the plant-specific locations per NUREG/CR-6260 are bounding for the generic NUREG/CR-6260 components. Second, the staff noted that the applicant's plant-specific configuration may contain locations that should be analyzed for the effects of reactor coolant environment, that are more limiting than those identified in NUREG/CR-6260. This may include locations that are limiting or bounding for a particular plant-specific configuration or that have calculated CUF values that are greater when compared to the locations identified in NUREG/CR-6260.

Request

1. Confirm and justify that the plant-specific locations listed in LRA Tables 4.3-13 and 4.3-14 are bounding for the generic NUREG/CR-6260 components.

**Response for RAI RCS-3 Part 1**

**A review of the locations provided in LRA Tables 4.3-13 and 4.3-14 confirmed that they are equivalent to the locations provided in NUREG/CR-6260.**

2. Confirm and justify that the locations selected for environmentally-assisted fatigue analyses in LRA Tables 4.3-13 and 4.3-14 consist of the most limiting locations *for the plant* (beyond the generic components identified in the NUREG/CR-6260 guidance). If these locations are not bounding, clarify which locations require an environmentally-assisted fatigue analysis and the actions that will be taken for these additional locations. If the limiting locations identified consist of nickel alloy, state whether the methodology used to perform environmentally-assisted fatigue calculation for nickel alloy is consistent with NUREG/CR-6909. If not, justify the method chosen.

**Response for RAI RCS-3 Part 2**

**Entergy 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 Indian Point plant 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. This evaluation will be completed prior to entering the period of extended operation.**

**Commitment**

**Entergy is providing the following new commitment (Commitment 43) for the Metal Fatigue NUREG/CR-6260;**

**Entergy 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 Indian Point 2 and 3 plant 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. This evaluation will be completed prior to the period of extended operation.**

**NRC WESTEMS Questions**

**Question #1**

**For any use of the WESTEMS "Design CUF" module in the future at IPEC, include written explanation and justification of any user intervention in the process.**

**Response for Question #1**

**IPEC will include written explanation and justification of user intervention in any future use of the WESTEMS "Design CUF" module. (Commitment 44)**

**Question #2**

**Provide a commitment that the NB-3600 option of the WESTEMS "Design CUF" module will not be implemented or used in the future at IPEC.**

**Response for Question #2**

**IPEC will not use the ASME Section III, NB-3600 option of the WESTEMS "Design CUF" module until the issues identified during the NRC review of the program has been resolved. (Commitment 45)**

**ATTACHMENT 2 TO NL-11-032**

**LICENSE RENEWAL APPLICATION**
**IPEC LIST OF REGULATORY COMITMENTS**

**Rev. 13**

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

List of Regulatory Commitments

Rev. 13

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

Changes are shown as strikethroughs for ~~deletions~~ and underlines for <u>additions</u>.

| # | 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.<br>Enhance the Aboveground Steel Tanks Program for IP2 and IP3 to require trending of thickness measurements when material loss is detected. | IP2: September 28, 2013<br>IP3: December 12, 2015 | NL-07-039 | A.2.1.1<br>A.3.1.1<br>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.<br>The Bolting Integrity Program manages loss of preload and loss of material for all external bolting. | IP2: September 28, 2013<br>IP3: December 12, 2015 | NL-07-039<br>NL-07-153 | A.2.1.2<br>A.3.1.2<br>B.1.2<br>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.<br>This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M34, Buried Piping and Tanks Inspection.<br>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:<br>September 28, 2013<br><br>IP3:<br>December 12, 2015 | NL-07-039<br><br>NL-07-153<br><br>NL-09-106<br><br>NL-09-111 | A.2.1.5<br>A.3.1.5<br>B.1.6<br>Audit Item 173 |

| # | COMMITMENT | IMPLEMENTATION SCHEDULE | SOURCE | RELATED LRA SECTION / AUDIT ITEM |
|---|---|---|---|---|
| 4 | Enhance the Diesel Fuel Monitoring Program to include cleaning and inspection of the IP2 GT-1 gas turbine fuel oil storage tanks, IP2 and IP3 EDG fuel oil day tanks, IP2 SBO/Appendix R diesel generator fuel oil day tank, and IP3 Appendix R fuel oil storage tank and day tank once every ten years.<br><br>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%.<br><br>Enhance the Diesel Fuel Monitoring Program to include thickness measurement of the bottom of the following tanks once every ten years. IP2: EDG fuel oil storage tanks, EDG fuel oil day tanks, SBO/Appendix R diesel generator fuel oil day tank, GT-1 gas turbine fuel oil storage tanks, and diesel fire pump fuel oil storage tank; IP3: EDG fuel oil day tanks, EDG fuel oil storage tanks, Appendix R fuel oil storage tank, and diesel fire pump fuel oil storage tank.<br><br>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.<br><br>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.<br><br>Enhance the Diesel Fuel Monitoring Program to direct samples be taken and include direction to remove water when detected.<br><br>Revise applicable procedures to direct sampling of the onsite portable fuel oil contents prior to transferring the contents to the storage tanks.<br><br>Enhance the Diesel Fuel Monitoring Program to direct the addition of chemicals including biocide when the presence of biological activity is confirmed. | IP2:<br>September 28, 2013<br><br>IP3:<br>December 12, 2015 | NL-07-039<br><br>NL-07-153<br><br>NL-08-057 | A.2.1.8<br>A.3.1.8<br>B.1.9<br>Audit items 128, 129, 132, 491, 492, 510 |

| # | COMMITMENT | IMPLEMENTATION SCHEDULE | SOURCE | RELATED LRA SECTION / AUDIT ITEM |
|---|---|---|---|---|
| 5 | Enhance the External Surfaces Monitoring Program for IP2 and IP3 to include periodic inspections of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(3). Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(2). | IP2: September 28, 2013<br><br>IP3: December 12, 2015 | NL-07-039 | A.2.1.10<br>A.3.1.10<br>B.1.11 |
| 6 | Enhance the Fatigue Monitoring Program for IP2 to monitor steady state cycles and feedwater cycles or perform an evaluation to determine monitoring is not required. Review the number of allowed events and resolve discrepancies between reference documents and monitoring procedures.<br><br>Enhance the Fatigue Monitoring Program for IP3 to include all the transients identified. Assure all fatigue analysis transients are included with the lowest limiting numbers. Update the number of design transients accumulated to date. | IP2: September 28, 2013<br><br>IP3: December 12, 2015 | NL-07-039<br><br>NL-07-153 | A.2.1.11<br>A.3.1.11<br>B.1.12,<br>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.<br><br>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.<br><br>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.<br><br>Enhance the Fire Protection Program for IP3 to visually inspect the cable spreading room, 480V switchgear room, and EDG room $CO_2$ fire suppression system for signs of degradation, such as corrosion and mechanical damage at least once every six months. | IP2: September 28, 2013<br><br>IP3: December 12, 2015 | NL-07-039 | A.2.1.12<br>A.3.1.12<br>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.<br><br>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.<br><br>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.<br><br>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:<br>September 28, 2013<br><br>IP3:<br>December 12, 2015 | NL-07-039<br><br>NL-07-153<br><br>NL-08-014 | A.2.1.13<br>A.3.1.13<br>B.1.14<br>Audit Items 105, 106 |

| # | COMMITMENT | IMPLEMENTATION SCHEDULE | SOURCE | RELATED LRA SECTION / AUDIT ITEM |
|---|---|---|---|---|
| 9 | Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to implement comparisons to wear rates identified in WCAP-12866. Include provisions to compare data to the previous performances and perform evaluations regarding change to test frequency and scope.<br><br>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.<br><br>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:<br>September 28, 2013<br><br>IP3:<br>December 12, 2015 | NL-07-039 | A.2.1.15<br>A.3.1.15<br>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.<br>• Safety injection pump lube oil heat exchangers<br>• RHR heat exchangers<br>• RHR pump seal coolers<br>• Non-regenerative heat exchangers<br>• Charging pump seal water heat exchangers<br>• Charging pump fluid drive coolers<br>• Charging pump crankcase oil coolers<br>• Spent fuel pit heat exchangers<br>• Secondary system steam generator sample coolers<br>• Waste gas compressor heat exchangers<br>• SBO/Appendix R diesel jacket water heat exchanger (IP2 only)<br><br>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.<br>Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to include consideration of material-environment combinations when determining sample population of heat exchangers.<br>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:<br>September 28, 2013<br><br>IP3:<br>December 12, 2015 | NL-07-039<br><br>NL-07-153<br><br>NL-09-018 | A.2.1.16<br>A.3.1.16<br>B.1.17,<br>Audit Item 52 |
| 11 | Delete commitment. | | NL-09-056 | |

| # | 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: September 28, 2013<br><br>IP3: December 12, 2015 | NL-07-039 | A.2.1.18<br>A.3.1.18<br>B.1.19 |
| 13 | Enhance the Metal-Enclosed Bus Inspection Program to add IP2 480V bus associated with substation A to the scope of bus inspected.<br><br>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.<br><br>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.<br><br>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.<br><br>The plant will process a change to applicable site procedure to remove the reference to “re-torquing” connections for phase bus maintenance and bolted connection maintenance. | IP2: September 28, 2013<br><br>IP3: December 12, 2015 | NL-07-039<br><br>NL-07-153<br><br>NL-08-057 | A.2.1.19<br>A.3.1.19<br>B.1.20<br>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: September 28, 2013<br><br>IP3: December 12, 2015 | NL-07-039 | A.2.1.21<br>A.3.1.21<br>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.<br><br>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:<br>September 28, 2013<br><br>IP3:<br>December 12, 2015 | NL-07-039<br><br>NL-07-153 | A.2.1.22<br>A.3.1.22<br>B.1.23<br>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.<br><br>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:<br>September 28, 2013<br><br>IP3:<br>December 12, 2015 | NL-07-039<br><br>NL-07-153 | A.2.1.23<br>A.3.1.23<br>B.1.24<br>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.<br><br>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:<br>September 28, 2013<br><br>IP3:<br>December 12, 2015 | NL-07-039<br><br>NL-07-153 | A.2.1.24<br>A.3.1.24<br>B.1.25<br>Audit item 173 |
| 18 | Enhance the Oil Analysis Program for IP2 to sample and analyze lubricating oil used in the SBO/Appendix R diesel generator consistent with oil analysis for other site diesel generators.<br><br>Enhance the Oil Analysis Program for IP2 and IP3 to sample and analyze generator seal oil and turbine hydraulic control oil.<br><br>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.<br><br>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:<br>September 28, 2013<br><br>IP3:<br>December 12, 2015 | NL-07-039 | A.2.1.25<br>A.3.1.25<br>B.1.26 |

| # | COMMITMENT | IMPLEMENTATION SCHEDULE | SOURCE | RELATED LRA SECTION / AUDIT ITEM |
|---|---|---|---|---|
| 19 | Implement the One-Time Inspection Program for IP2 and IP3 as described in LRA Section B.1.27.<br>This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M32, One-Time Inspection. | IP2:<br>September 28, 2013<br>IP3:<br>December 12, 2015 | NL-07-039<br>NL-07-153 | A.2.1.26<br>A.3.1.26<br>B.1.27<br>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.<br>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:<br>September 28, 2013<br>IP3:<br>December 12, 2015 | NL-07-039<br>NL-07-153 | A.2.1.27<br>A.3.1.27<br>B.1.28<br>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:<br>September 28, 2013<br>IP3:<br>December 12, 2015 | NL-07-039 | A.2.1.28<br>A.3.1.28<br>B.1.29 |
| 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.<br>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:<br>September 28, 2013<br>IP3:<br>December 12, 2015 | NL-07-039 | A.2.1.31<br>A.3.1.31<br>B.1.32 |
| 23 | Implement the Selective Leaching Program for IP2 and IP3 as described in LRA Section B.1.33.<br>This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M33 Selective Leaching of Materials. | IP2:<br>September 28, 2013<br>IP3:<br>December 12, 2015 | NL-07-039<br>NL-07-153 | A.2.1.32<br>A.3.1.32<br>B.1.33<br>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:<br>September 28, 2013<br>IP3:<br>December 12, 2015 | NL-07-039 | A.2.1.34<br>A.3.1.34<br>B.1.35 |

| # | COMMITMENT | IMPLEMENTATION SCHEDULE | SOURCE | RELATED LRA SECTION / AUDIT ITEM |
|---|---|---|---|---|
| 25 | Enhance the Structures Monitoring Program to explicitly specify that the following structures are included in the program.<br>• Appendix R diesel generator foundation (IP3)<br>• Appendix R diesel generator fuel oil tank vault (IP3)<br>• Appendix R diesel generator switchgear and enclosure (IP3)<br>• city water storage tank foundation<br>• condensate storage tanks foundation (IP3)<br>• containment access facility and annex (IP3)<br>• discharge canal (IP2/3)<br>• emergency lighting poles and foundations (IP2/3)<br>• fire pumphouse (IP2)<br>• fire protection pumphouse (IP3)<br>• fire water storage tank foundations (IP2/3)<br>• gas turbine 1 fuel storage tank foundation<br>• maintenance and outage building-elevated passageway (IP2)<br>• new station security building (IP2)<br>• nuclear service building (IP1)<br>• primary water storage tank foundation (IP3)<br>• refueling water storage tank foundation (IP3)<br>• security access and office building (IP3)<br>• service water pipe chase (IP2/3)<br>• service water valve pit (IP3)<br>• superheater stack<br>• transformer/switchyard support structures (IP2)<br>• waste holdup tank pits (IP2/3)<br><br>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.<br><br>• cable trays and supports<br>• concrete portion of reactor vessel supports<br>• conduits and supports<br>• cranes, rails and girders<br>• equipment pads and foundations<br>• fire proofing (pyrocrete)<br>• HVAC duct supports<br>• jib cranes<br>• manholes and duct banks<br>• manways, hatches and hatch covers<br>• monorails | IP2:<br>September 28, 2013<br><br>IP3:<br>December 12, 2015 | NL-07-039<br><br>NL-07-153<br><br>NL-08-057 | A.2.1.35<br>A.3.1.35<br>B.1.36<br><br>Audit items 86, 87, 88, 417 |

| # | COMMITMENT | IMPLEMENTATION SCHEDULE | SOURCE | RELATED LRA SECTION / AUDIT ITEM |
|---|---|---|---|---|
| | • new fuel storage racks<br>• sumps, sump screens, strainers and flow barriers<br><br>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.<br><br>Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspections of elastomers (seals, gaskets, seismic joint filler, and roof elastomers) to identify cracking and change in material properties and for inspection of aluminum vents and louvers to identify loss of material. | | | |
| | Enhance the Structures Monitoring Program for IP2 and IP3 to perform an engineering evaluation of groundwater samples to assess aggressiveness of groundwater to concrete on a periodic basis (at least once every five years). IPEC will obtain samples from at least 5 wells that are representative of the ground water surrounding below-grade site structures and perform an engineering evaluation of the results from those samples for sulfates, pH and chlorides. Additionally, to assess potential indications of spent fuel pool leakage, IPEC will sample for tritium in groundwater wells in close proximity to the IP2 spent fuel pool at least once every 3 months.<br><br>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. | | NL-08-127 | Audit Item 360 |
| | Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspection of the degraded areas of the water control structure once per 3 years rather than the normal frequency of once per 5 years during the PEO. | | | Audit Item 358 |

| # | COMMITMENT | IMPLEMENTATION SCHEDULE | SOURCE | RELATED LRA SECTION / AUDIT ITEM |
|---|---|---|---|---|
| | 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-11-032 | |
| 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.<br>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:<br>September 28, 2013<br>IP3:<br>December 12, 2015 | NL-07-039<br>NL-07-153 | A.2.1.36<br>A.3.1.36<br>B.1.37<br>Audit item 173 |
| 27 | Implement the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.38.<br>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:<br>September 28, 2013<br>IP3:<br>December 12, 2015 | NL-07-039<br>NL-07-153 | A.2.1.37<br>A.3.1.37<br>B.1.38<br>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.<br>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:<br>September 28, 2013<br>IP3:<br>December 12, 2015 | NL-07-039<br>NL-08-057 | A.2.1.39<br>A.3.1.39<br>B.1.40<br>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:<br>September 28, 2013 | NL-07-039 | A.2.1.40<br>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:<br>September 28, 2011<br>IP3:<br>December 12, 2013 | NL-07-039 | A.2.1.41<br>A.3.1.41 |

| # | COMMITMENT | IMPLEMENTATION SCHEDULE | SOURCE | RELATED LRA SECTION / AUDIT ITEM |
|---|---|---|---|---|
| 31 | Additional P-T curves will be submitted as required per 10 CFR 50, Appendix G prior to the period of extended operation as part of the Reactor Vessel Surveillance Program. | IP2: September 28, 2013<br><br>IP3: December 12, 2015 | NL-07-039 | A.2.2.1.2<br>A.3.2.1.2<br>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<br><br>NL-08-127 | A.3.2.1.4<br>4.2.5 |
| 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:<br><br>(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:<br><br>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.<br><br>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.<br><br>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.<br><br>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.<br><br>(2) Consistent with the Fatigue Monitoring Program, Corrective Actions, repair or replace the affected locations before exceeding a CUF of 1.0. | IP2: September 28, 2011<br><br>IP3: December 12, 2013<br><br>Complete | NL-07-039<br><br>NL-07-153<br><br>NL-08-021<br><br>NL-10-082 | A.2.2.2.3<br>A.3.2.2.3<br>4.3.3<br>Audit item 146 |

| # | COMMITMENT | IMPLEMENTATION SCHEDULE | SOURCE | RELATED LRA SECTION / AUDIT ITEM |
|---|---|---|---|---|
| 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 50.59l(1) and, therefore, a license amendment pursuant to 10 CFR 50.90 is not required. | April 30, 2008<br><br>Complete | NL-07-078<br><br>NL-08-074 | 2.1.1.3.5 |
| 35 | Perform a one-time inspection of representative sample area of IP2 containment liner affected by the 1973 event behind the insulation, prior to entering the extended period of operation, to assure liner degradation is not occurring in this area.<br><br>Perform a one-time inspection of representative sample area of the IP3 containment steel liner at the juncture with the concrete floor slab, prior to entering the extended period of operation, to assure liner degradation is not occurring in this area.<br><br>Any degradation will be evaluated for updating of the containment liner analyses as needed. | IP2:<br>September 28, 2013<br><br>IP3:<br>December 12, 2015 | NL-08-127<br><br>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.<br><br>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.<br><br>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:<br>September 28, 2013 | NL-08-127<br><br>NL-09-056<br><br>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:<br>September 28, 2013<br><br>IP3:<br>December 12, 2015 | NL-08-127 | 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 $C_V$USE, updated calculations will be provided to the NRC. | IP2: September 28, 2013<br><br>IP3: December 12, 2015 | NL-08-143 | 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: September 28, 2013<br><br>IP3: December 12, 2015 | NL-09-106 | B.1.6<br>B.1.22<br>B.1.23<br>B.1.24<br>B.1.25<br>B.1.27<br>B.1.28<br>B.1.33<br>B.1.37<br>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 welds. The steam generator divider plate inspections will be completed within the first ten years of the period of extended operation (PEO). | IP2: Prior to September 28, 2023<br><br>IP3: Prior to December 12, 2025 | NL-11-032 | 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.<br><br>Option 1 (Analysis)<br><br>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 will be submitted as part of a license amendment request requiring approval from the NRC.<br><br>Option 2 (Inspection)<br><br>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:<br>a. The condition will be resolved through repair or engineering evaluation to justify continued service, as appropriate, and<br>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<br><br>IP3: Within the first 2 refueling outages following the beginning of the PEO. | NL-11-032 | 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.<br><br>IPEC will use the NUREG/CR-6909 methodology in the evaluation of the limiting locations consisting of nickel alloy, if any. | IP2:<br>Prior to September 28, 2013<br><br>IP3: Prior to December 12, 2015 | NL-11-032 | 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. | Within 60 days of issuance of the renewed operating license. | NL-11-032 | 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. | Within 60 days of issuance of the renewed operating license. | NL-11-032 | N/A |
| 46 | Include in the IP2 ISI Program volumetric weld metal inspections of ten socket welds in 2012 and of at least ten socket welds during each 10-year period of the period of extended operation. | IP2:<br>Prior to September 28, 2013 | NL-11-032 | N/A |