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NL-17-084

July 27, 2017

U.S. Nuclear Regulatory Commission
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SUBJECT: Reply to Requests for Additional Information for the Review of the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application RAI SET 2017-06 (CAC Nos. MD5407 and MD5408)
Docket Nos. 50-247 and 50-286
License Nos. DPR-26 and DPR-64

REFERENCES:

1) NRC letter dated June 27, 2017, "Requests for Additional Information for the Review of the Indian Point License Renewal Application RAI SET 2017-06 (CAC Nos. MD5407 and MD5408)," (ML17170A286)

2) Entergy letter dated April 28, 2017, "Supplemental Information Associated with NRC issuance of LR-ISG-2015-01, "Changes to Buried and Underground Piping and Tank Recommendations," for the Review of the Indian Point Nuclear Generating Unit Nos. 2 and 3 License Renewal Application (NL-17-048)

3) Entergy letter dated July 24, 2013, "Reply to Request for Additional Information Regarding the License Renewal Application," Indian Point Nuclear Generating Unit Nos. 2 and 3 (NL-13-098)

4) Entergy letter dated March 5, 2013, "Revision to the Response to Request for Additional Information (RAI) Aging Management Programs," Indian Point Nuclear Generating Unit Nos. 2 and 3 (NL-13-037)

Dear Sir or Madam:

Entergy Nuclear Operations, Inc. (Entergy) is providing in Attachment 1, the additional information requested by the U.S. Nuclear Regulatory Commission (NRC) pertaining to the review of the License Renewal Application (LRA) for Indian Point Energy Center (IPEC) Unit Nos. 2 and 3 (Reference 1).

Changes to the LRA sections resulting from the responses in Attachment 1 are provided in Attachment 2. Changes to the List of Regulatory Commitments are provided in Attachment 3.

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NRR

In addition to the new Commitment # 55, Commitment # 51 was revised to add a reference that was inadvertently removed in letter NL-17-052 dated May 8, 2017.

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

I declare under penalty of perjury that the foregoing is true and correct. Executed on 7/27, 2017.

Sincerely,

AJV/rl

Attachments:

1. Reply to NRC Request for Additional Information Regarding the License Renewal Application
2. License Renewal Application Changes Due to Responses to Requests for Additional Information
3. License Renewal Application IPEC List of Regulatory Commitments Revision 34

cc: Mr. Daniel H. Dorman, Regional Administrator, NRC Region I
Mr. Sherwin E. Turk, NRC Office of General Counsel, Special Counsel
Mr. William Burton, NRC Senior Project Manager, Division of License Renewal
Mr. Richard V. Guzman, NRR Senior Project Manager
Ms. Bridget Frymire, New York State Department of Public Service
Ms. Alicia Barton, President and CEO NYSERDA
NRC Resident Inspector's Office

ATTACHMENT 1

to NL-17-084

REPLY TO NRC REQUEST FOR ADDITIONAL INFORMATION

REGARDING THE

LICENSE RENEWAL APPLICATION

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

RAI 3.0.3.1.2-1

Background

GALL Report AMP XI.M41, "Buried and Underground Piping and Tanks," as modified by LR-ISG-2015-01, "Changes to Buried and Underground Piping and Tank Recommendations," includes the following recommendations:

1. The "preventive actions" program element recommends that coatings are provided for buried stainless steel or the applicant provides justification when coatings are not provided.
2. Table XI.M41-2, "Inspection of Buried and Underground Piping and Tanks," recommends one inspection of buried stainless steel piping during each 10-year period, commencing 10 years prior to the period of extended operation.

Issue

The number of recommended inspections for buried stainless steel in GALL Report AMP XI.M41, as modified by LR-ISG-2015-01, is based on coatings being provided or adequate justification when coatings are not provided. It is unclear to the staff if buried stainless steel piping is coated, and if it is not coated, the justification for why coatings do not need to be provided.

Request

State if buried stainless steel piping is coated. If buried stainless steel piping is not coated, provide justification (e.g., increased extent or frequency of inspections, soil parameters) for why coatings do not need to be provided.

Response

Buried stainless steel piping subject to aging management review for license renewal is not coated at IPEC. As stated in NL-13-098, dated July 24, 2013, IPEC has performed soil testing and other surveys that have determined that the soils are non-aggressive (i.e., negligible degree of corrosivity). As stated in NL 13-037, dated March 5, 2013, IPEC will perform two (2) inspections of stainless steel piping during the period of extended operation (PEO) which exceeds the recommendations of the ISG for coated stainless steel piping. Inspections performed prior to the PEO detected no significant corrosion of buried stainless steel piping.

RAI 3.0.3.1.2-2

Background

Attachment 1 of letter dated April 28, 2017, states that polyvinyl chloride (PVC) piping exposed to soil has no aging effects due to the lack of stressors in a soil environment and non-aggressive soil as confirmed by soil samples.

GALL Report AMP XI.M41, as modified by LR-ISG-2015-01, includes the following recommendations:

1. The "parameters monitored or inspected" program element recommends visual inspections of the external surface condition of polymeric materials to detect loss of material due to wear.
2. Table XI.M41-2, "Inspection of Buried and Underground Piping and Tanks," recommends one inspection of buried polymeric piping when backfill is in accordance with the "preventive actions" program element, and the smaller of one percent of the length of the pipe or two inspections when backfill is not in accordance with the "preventive actions" program element.

Issue

As noted above, GALL Report AMP XI.M41, as modified by LR-ISG-2015-01, recommends reducing the number of inspections for polymeric piping based on backfill quality, but does not recommend eliminating inspections based on soil aggressiveness. It is unclear to the staff how lack of stressors in a soil environment and non-aggressive soil as confirmed by soil samples precludes the need to perform visual inspections to detect loss of material due to wear.

Request

State the basis for why loss of material due to wear is not an aging effect requiring management for PVC piping exposed to soil. Alternatively, revise the program to address loss of material due to wear for buried PVC piping.

Response

The piping in question is schedule 80 PVC that was installed in 2008. The PVC piping that is in scope and subject to aging management review is placed with backfill around the piping consisting of 6 inches of sand free of any foreign material that could result in wear. Nevertheless, IPEC will identify loss of material due to wear as an aging effect and inspect the piping in accordance with the recommendations of LR-ISG-2015-01. Because the backfill meets the provisions of the ISG, IPEC will perform one inspection per unit every 10 years during the period of extended operation. The resulting changes to LRA Section 3.3.2.1.18, LRA Tables 3.3.2-18-IP2 and 3.3.2-18-IP3, and LRA Appendix A and Appendix B are shown in Attachment 2. Additions are underlined and deletions are lined through.

RAI 3.0.3.1.2-3

Background

Attachment 1 of letter dated April 28, 2017, states "[c]athodic protection levels are maintained as described in NL-13-132 [response to RAI 3.0.3.1.2-4a dated October 3, 2013] and soil conditions are not aggressive such that cracking is not an aging effect requiring management. In addition, the stainless steel piping in the program operates at temperatures below 140°F, which is the threshold for stress corrosion cracking in stainless steel."

GALL Report AMP XI.M41, as modified by LR-ISG-2015-01, provides the following recommendations:

1. Stainless steel components can experience stress corrosion cracking when exposed to soil due to the potential presence of halides.
2. Steel components can experience stress corrosion cracking when exposed to a carbonate/bicarbonate environment depending on cathodic polarization level, temperature, and pH. See NACE SP0169-2013, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems," Figure 2, "SCC [stress corrosion cracking] Range of Pipe Steel in Carbonate/Bicarbonate Environments."

Issue

1. The threshold temperature for stress corrosion cracking of stainless steel in a treated water environment (i.e. water whose chemistry has been altered and is maintained) is 140°F; however, due to the potential presence of halides, stress corrosion cracking is an applicable aging effect for stainless steel piping exposed to soil.
2. The subject letter does not address cracking of steel exposed to soil, which can occur in a carbonate/bicarbonate environment depending on cathodic polarization level, temperature, and pH. It is unclear to the staff if steel piping is exposed to a carbonate/bicarbonate environment, and if it is, how factors such as cathodic polarization level, temperature, and pH preclude the need to manage steel piping for cracking.

Request

1. For buried stainless steel components, state the specific soil parameters (e.g., bacteria, presence of halogens) and results that demonstrate that cracking will not occur. Alternatively, revise the program to address cracking of buried stainless steel piping.
2. State the basis for why cracking is not an aging effect requiring management for steel piping exposed to soil. Alternatively, revise the program to address cracking of buried steel piping.

Response

1. At IPEC soil parameters are monitored in accordance with the provisions of AWWA C105. There is no data on halogens or bacteria. The most recent analyses in 2013 showed the following:

   Chlorides: 1.33 - 7.45 ppm
   Resistivity: 16,000 – 99,000 ohm*cm
   Sulfides were not detectable

   Soils containing less than 50 ppm chlorides, coupled with a resistivity of more than 10,000 ohm*cm, are categorized as "non-corrosive" soils relative to buried structures like galvanized-steel and iron-cast pipes. IPEC soil analysis concluded that even when assuming conservative values for redox potential, the soils at IPEC have a low corrosivity potential. In addition, the lack of detectable sulfides and low levels of chlorides in the soil surrounding the buried stainless steel safety injection system piping results in a minimal potential for cracking of the piping. As a result, cracking of stainless steel piping is not an aging effect requiring management. However, IPEC will perform a visual examination of stainless steel piping surfaces for evidence of cracking whenever piping surfaces are exposed during the period of extended operation. Provisions for these inspections have been included in LRA Sections A.3.1.5 and B.1.6 as shown in Attachment 2. Additions are underlined and deletions are lined through.

2. Cracking of carbon steel piping has been documented in the oil and gas pipeline industry but not in the nuclear industry. The cracking in the gas industry was documented as either high pH or neutral pH cracking. There are several potential reasons for the lack of similar operating experience in the nuclear industry. The most significant reason is the low operating pressures of buried piping at nuclear plants compared to operating pressures in gas pipelines. The significantly lower pressures result in lower hoop stresses on the pipe walls and a resultant lower likelihood of cracking. In addition, buried nuclear piping operates at relatively low temperatures, which also lowers the likelihood of high or neutral pH cracking and the potential impact of variances in the cathodic protection potential level.

   The piping exposed to soil in the scope of the program at IPEC is in low-temperature and low-pressure systems. IPEC soil samples in 2013 indicated pH in a range from 7.83 to 9.29. Based on this high basic pH, the potential for a carbonate/bicarbonate environment cannot be eliminated. However, this environment by itself does not create the potential for cracking of carbon steel. Cracking also requires stress and a breach in the protective coating on a susceptible material. The operating stresses at IPEC are low and the carbon steel material is coated with coal tar epoxy. Because of the low stress, the potential for cracking is very low even with a breach of the protective coating. The limited number of cathodic protection systems at IPEC are monitored and controlled to polarization levels that when combined with the low operating stresses, reduce the potential for cracking. As a result of these conditions, cracking is not an aging effect requiring management. However, IPEC will perform a visual examination of carbon steel piping surfaces for evidence of cracking whenever piping surfaces are exposed during the period of extended operation. Provisions for these inspections have been included in LRA Sections A.2.1.5, A.3.1.5 and B.1.6 as shown in Attachment 2. Additions are underlined and deletions are lined through.

RAI 3.0.3.1.2-4

Background

As amended by letter dated April 28, 2017, LRA Section B.1.6, "Buried Piping and Tanks Inspection," states "[i]f future inspections reveal significant coating damage caused by non-conforming backfill, then Entergy will double the inspection sample size up to an increase of five (5) inspections."

GALL Report AMP XI.M41, as modified by LR-ISG-2015-01, states that where the coatings, backfill or the condition of exposed piping does not meet acceptance criteria such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is extrapolated to the end of the period of extended operation, an increase in the sample size is conducted.

Issue

The staff noted that degradation of the base metal could occur for reasons besides significant coating damage caused by non-conforming backfill (e.g., coating degradation based on coating service life). Significant coating damage caused by non-conforming backfill is only an example of how degradation of the base metal could occur. In addition, in contrast to AMP XI.M41, which defines the degree of degradation (i.e., loss of pressure boundary function), "significant coating damage" is not defined.

Request

State the basis for why an increase in inspection sample size will only occur when significant coating damage caused by non-conforming backfill is revealed. Alternatively, revise the program to be consistent with LR-ISG-2015-01 regarding criteria for increasing inspection sample size.

Response

Appendix B.1.6 is revised to state "Where the coatings, backfill, or the condition of exposed piping does not meet acceptance criteria, the degraded condition is repaired or the affected component is replaced. In addition, where the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material is extrapolated to the end of the period of extended operation, an expansion of sample size is conducted. The number of inspections within the affected piping categories are doubled or increased by 5, whichever is smaller." This is consistent with LR-ISG-2015-01. The changes to LRA Appendix A, Sections A.2.1.5 and A.3.1.5 and LRA Appendix B, Section B.1.6 are shown in Attachment 2. Additions are underlined and deletions are lined through.

RAI 3.0.3.1.2-5

Background

As amended by letter dated April 28, 2017, LRA Sections A.2.1.5 and A.3.1.5 (Buried Piping and Tanks Inspection program UFSAR summary descriptions for Units 2 and 3, respectively) were revised in response to the issuance of LR-ISG-2015-01.
The UFSAR summary description issued in LR-ISG-2015-01 includes the following recommendations:

- This program manages the aging effects of cracking.
- Inspections are conducted by qualified individuals.
- Where the coatings, backfill or the condition of exposed piping does not meet acceptance criteria such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is

extrapolated to the end of the period of extended operation, an increase in the sample size is conducted.

Issue

The staff noted that aspects of the UFSAR summary description issued in LR-ISG-2015-01 (bulletized above) were not included in the revised LRA Sections A.2.1.5 and A.3.1.5. The licensing basis for this program for the period of extended operation may not be adequate if the applicant does not incorporate this information in its UFSAR supplement.

Request

State the basis for not including aspects of the UFSAR Summary Description issued in LR-ISG-2015-01 (bulletized above) in the revised LRA Sections A.2.1.5 and A.3.1.5. Alternatively, revise LRA Sections A.2.1.5 and A.3.1.5 to be consistent with LR-ISG-2015-01.

Response

LRA Sections A.2.1.5 and A.3.1.5 and B.1.6 are revised to include the items as discussed in the background section in the request above with the exception of managing the aging effect of cracking. As discussed in response to RAI 3.0.3.1.2-3, cracking was not identified as an aging effect requiring management. However, provisions were added to inspect piping for cracking whenever piping surfaces are exposed. Changes to the license renewal application are shown in Attachment 2. Additions are underlined and deletions are lined through.

ATTACHMENT 2

to NL-17-084

LICENSE RENEWAL APPLICATION CHANGES

DUE TO RESPONSES TO REQUESTS FOR ADDITIONAL INFORMATION

Deletions are shown with strikethroughs and additions are underlined.

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

3.3.2.1.18 Plant Drains

Materials

Plant drains components are constructed of the following materials.

- carbon steel
- stainless steel
- gray cast iron
- plastic
- copper alloy > 15% zinc

Environment

Plant drains components are exposed to the following environments.

- air – indoor
- air – outdoor
- concrete
- gas
- raw water
- soil
- treated borated water

Aging Effects Requiring Management

The following aging effects associated with the plant drains require management.

- loss of material
- loss of material - wear

Table 3.3.2-18-IP2: Plant Drains

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
Piping	Pressure Boundary	Plastic	Air-Indoor (int)	None	None	--	--	F
Piping	Pressure Boundary	Plastic	Air-Indoor (ext)	None	None	--	--	F
Piping	Pressure Boundary	Plastic	Soil (ext)	~~None~~ Loss of material - wear	~~None~~ Buried Piping and Tanks Inspection	--	--	F
Strainer	Filtration	Carbon steel	Air – indoor (ext)	Loss of material	External Surfaces Monitoring	VII.I-8 (A-77)	3.3.1-58	A
Strainer	Filtration	Stainless steel	Air – indoor (ext)	None	None	VII.J-15 (AP-17)	3.3.1-94	A
Tubing	Pressure boundary	Stainless steel	Air – indoor (ext)	None	None	VII.J-15 (AP-17)	3.3.1-94	A
Tubing	Pressure boundary	Stainless steel	Raw water (int)	Loss of material	One-Time Inspection	VII.C1-15 (A-54)	3.3.1-79	E
Valve body	Pressure boundary	Carbon steel	Air – indoor (ext)	Loss of material	External Surfaces Monitoring	VII.I-8 (A-77)	3.3.1-58	A

Table 3.3.2-18-IP3: Plant Drains								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Programs**	**NUREG-1801 Vol. 2 Item**	**Table 1 Item**	**Notes**
Piping	Pressure Boundary	Plastic	Air-Indoor (int)	None	None	--	--	F
Piping	Pressure Boundary	Plastic	Air-Indoor (ext)	None	None	--	--	F
Piping	Pressure Boundary	Plastic	Soil (ext)	~~None~~ Loss of material - wear	~~None~~ Buried Piping and Tanks Inspection	--	--	F
Strainer	Filtration	Carbon steel	Air – indoor (ext)	Loss of material	External Surfaces Monitoring	VII.I-8 (A-77)	3.3.1-58	A
Strainer	Filtration	Stainless steel	Air – indoor (ext)	None	None	VII.J-15 (AP-17)	3.3.1-94	A

A.2.1.5 Buried Piping and Tanks Inspection Program

The Buried Piping and Tanks Inspection Program is a new program that includes (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried and underground carbon steel, copper alloy, gray cast iron, and stainless steel components. The program manages loss of material for bolting on piping and loss of material due to wear on plastic piping within the scope of the program. Preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings. Buried components are inspected when excavated during maintenance. If trending within the corrective action program identifies susceptible locations, the areas with a history of corrosion problems are evaluated for the need for additional inspection, alternate coating, or replacement. Cathodic protection (CP) systems installed at IPEC provide additional protection of license renewal in-scope buried piping and minimize corrosion in areas that have been found susceptible to corrosion based on indirect inspections or testing. To the extent they are proven effective, the CP systems at IPEC will be considered in risk ranking to ensure that the in-scope buried piping systems that are more susceptible to external corrosion continue to receive a higher risk ranking when determining inspection priority. IPEC will perform CP surveys at least once every twelve (12) months.

IP2 will perform 20 direct visual inspections of buried piping during the 10-year period prior to the PEO. IP2 will perform 14 direct visual inspections of carbon steel/copper alloy buried piping during each 10-year period of the PEO. One inspection of buried plastic (PVC) piping will be performed during each 10-year period of the PEO. Inspections are conducted by qualified individuals. IPEC will perform a visual examination of carbon steel piping surfaces for evidence of cracking whenever piping surfaces are exposed during the period of extended operation. Soil samples will be taken prior to the PEO and at least once every 10 years in the PEO. Soil will be tested at a minimum of two locations at least three feet below the surface near in-scope piping to determine representative soil conditions for each system. If test results indicate the soil is corrosive then the number of carbon steel/copper alloy piping inspections will be increased to 20 during each 10-year period of the PEO. Visual inspections will be supplemented with surface or volumetric non-destructive testing if indications of significant loss of material are observed. Measured wall thickness will be projected to the end of the period of extended operation to ensure minimum wall thickness requirements are met. Where the coatings, backfill or the condition of exposed piping does not meet acceptance criteria such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is extrapolated to the end of the period of extended operation, an increase in the sample size is conducted. The number of inspections within the affected piping categories are doubled or increased by 5, whichever is smaller.

A.3.1.5 Buried Piping and Tanks Inspection Program

The Buried Piping and Tanks Inspection Program is a new program that includes (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried and underground carbon steel, gray cast iron, copper alloy and stainless steel components. The program manages loss of material for bolting on piping and loss of material due to wear on plastic piping within the scope of the program. Preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings. Buried components are inspected when excavated during maintenance. If trending within the corrective action program identifies susceptible locations, the areas with a history of corrosion problems are evaluated for the need for additional inspection, alternate coating, or replacement. Cathodic protection (CP) systems installed at IPEC provide additional protection of license renewal in-scope buried piping and minimize corrosion in areas that have been found susceptible to corrosion based on indirect inspections or testing. To the extent they are proven effective, the CP systems at IPEC will be considered in risk ranking to ensure that the in-scope buried piping systems that are more susceptible to external corrosion continue to receive a higher risk ranking when determining inspection priority. IPEC will perform CP surveys at least once every twelve (12) months.

IP3 will perform 14 direct visual inspections of buried piping during the 10-year period prior the PEO. IP3 will perform 16 direct visual inspections of carbon steel/copper alloy and stainless steel buried piping during each 10-year period of the PEO. One inspection of buried plastic (PVC) piping will be performed during each 10-year period of the PEO. Inspections are conducted by qualified individuals. IPEC will perform a visual examination of carbon and stainless steel piping surfaces for evidence of cracking whenever piping surfaces are exposed during the period of extended operation. Soil samples will be taken prior to the PEO and at least once every 10 years into the PEO. Soil will be tested at a minimum of two locations at least three feet below the surface near in-scope piping to determine representative soil conditions for each system. If test results indicate the soil is corrosive then the number of carbon steel/copper alloy piping inspections will be increased to 22 during each 10-year period of the PEO. Visual inspections will be supplemented with surface or volumetric non-destructive testing if indications of significant loss of material are observed. Measured wall thickness will be projected to the end of the period of extended operation to ensure minimum wall thickness requirements are met. Where the coatings, backfill or the condition of exposed piping does not meet acceptance criteria such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is extrapolated to the end of the period of extended operation, an increase in the sample size is conducted. The number of inspections within the affected piping categories are doubled or increased by 5, whichever is smaller.

B.1.6 BURIED PIPING AND TANKS INSPECTION

Program Description

The Buried Piping and Tanks Inspection Program is a new program that includes (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried and underground carbon steel, gray cast iron, copper alloy and stainless steel components. The program manages loss of material for bolting on piping and loss of material due to wear on plastic piping within the scope of the program. Preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings. Buried components are inspected when excavated during maintenance. If trending within the corrective action program identifies susceptible locations, the areas with a history of corrosion problems are evaluated for the need for additional inspection, alternate coating, or replacement. The program applies to buried components in the following systems.

- Safety injection
- Service water

• Fire protection

• Fuel oil

• Security generator

• City water

• Plant drains

• Auxiliary feedwater

• Containment isolation support

• River water service (IP1)

• Circulating water system (IP2)

• Instrument air (IP2)

Of these systems, only the safety injection system contains radioactive fluids during normal operations. The safety injection system buried components are stainless steel. Stainless steel is used in the safety injection system for its corrosion resistance. This program also applies to underground components in the IP3 service water and city water systems and the IP2 and IP3 fuel oil systems.

Cathodic protection systems installed at IPEC provide additional protection of license renewal in-scope buried piping and minimize corrosion in areas that have been found susceptible to corrosion based on indirect inspections (i.e., guided wave inspections) or testing (e.g., AP-EC surveys). To the extent they are proven effective, the CP systems at IPEC will be considered in risk ranking to ensure that the in-scope buried piping systems more susceptible to external corrosion continue to receive a higher risk ranking when determining inspection priority.

The CP systems will be monitored with the following acceptance criteria.

- Minimum -850 mV instant-off soil-to-pipe potential relative to a copper/copper sulfate reference electrode

- Maximum -1200 mV instant-off soil-to-pipe potential relative to a copper/copper sulfate reference electrode

- Minimum availability of 85%. The percent of system availability is calculated by determining the percent of the time the rectifiers are in service providing cathodic protection. "In service" is defined as rectifier current output values greater than zero amps or zero volts. The time the system is out of service for testing is not included in the calculation of system availability.

- Minimum of 80% CP system effectiveness. Test locations must meet a soil-to-pipe potential of instant-off -850 mV to -1200 mV relative to a copper/copper sulfate reference electrode. The percent of CP effectiveness is calculated by using the last measured values at each test station and dividing the total number of CP survey points that meet the required acceptance criteria by the total number of points surveyed during the monitoring period.

Failure to meet these acceptance criteria will result in no credit being taken for the CP system in the risk ranking process. IPEC will perform CP surveys at least once every twelve (12) months.

The Buried Piping and Tanks Inspection Program will be modified based on operating experience to include a risk assessment of in-scope buried piping and tanks that includes consideration of the impacts of buried piping tank or tank leakage and of conditions affecting the risk for corrosion. The program will 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. Corrosion risk will be determined through consideration of piping or tank material, soil resistivity, drainage, the presence of cathodic protection and the type of coating. Inspection priority and frequency for periodic inspections of the in-scope piping and tanks will be based on the results of the risk assessment.

Inspections will be performed using qualified inspection techniques with demonstrated effectiveness. <u>IPEC will perform a visual examination of carbon and stainless steel piping surfaces for evidence of cracking whenever piping surfaces are exposed during the period of extended operation.</u> Visual inspections will be supplemented with surface or volumetric non-destructive testing if indications of significant loss of material are observed. Measured wall thickness will be projected to the end of the period of extended operation to ensure minimum wall thickness requirements are met. Inspections will begin prior to the period of extended operation.

<u>Where the coatings, backfill, or the condition of exposed piping does not meet acceptance criteria, the degraded condition is repaired or the affected component is replaced. In addition, where the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material is extrapolated to the end of the period of extended operation, an expansion of sample size is conducted. The number of inspections within the affected piping categories are doubled or increased by 5, whichever is smaller.</u> ~~If future inspections reveal significant coating damage caused by non-conforming backfill, then Entergy will double the inspection sample size up to an increase of five (5) inspections.~~ If adverse indications are found in the expanded inspection sample, then Entergy will determine the extent of condition and the extent of cause. The size of the follow-up inspection sample will be determined based on the extent of condition and the extent of cause. The timing of the additional examinations will be based on the severity of the degradation and will be commensurate with the consequences of a leak or loss of function from the affected pipe. In all cases, the expanded sample inspections will be completed within the 10-year interval in which the original adverse indication was identified or, if identified in the latter half of the 10-year interval, within 4 years after the end of the 10-year interval. Sample size expansion may be limited by the extent of piping or tanks subject to the observed degradation mechanism.

Underground piping within the scope of license renewal and subject to aging management review will be visually inspected prior to the period of extended operation and then on a frequency of at least once every two years during the period of extended operation. This inspection frequency will be maintained unless the piping is subsequently coated in accordance with the preventive actions specified in NUREG-1801 Section XI.M41 as modified by LR-ISG-2015-01. Visual inspections will be supplemented with surface or volumetric non-destructive testing if indications of significant loss of material are observed. Measured wall thickness will be projected to the end of the period of extended operation to ensure minimum wall thickness requirements are met._Consistent with revised NUREG-1801 Section XI.M41, such adverse indications will be entered into the plant corrective action program for evaluation of extent of condition and for determination of appropriate corrective actions (e.g., increased inspection frequency, repair, replacement).

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

NUREG-1801 Consistency

The Buried Piping and Tanks Inspection Program will be consistent with program attributes described in NUREG-1801, Section XI.M34, Buried Piping and Tanks Inspection.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The Buried Piping and Tanks Inspection Program is a new program. Plant and industry 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 IPEC program is based on the program description in NUREG-1801, which in turn is based on industry operating experience. As such, operating experience assures that implementation of the Buried Piping and Tanks Inspection 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 Buried Piping and Tanks Inspection Program will be effective for managing aging effects since it will incorporate proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls. The Buried Piping and Tanks Inspection Program assures 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.

ATTACHMENT 3

to NL-17-084

LICENSE RENEWAL APPLICATION

IPEC LIST OF REGULATORY COMMITMENTS

Rev. 34

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

List of Regulatory Commitments

Rev. 34

The following table identifies those actions committed to by Entergy in this document. Changes are shown as strikethroughs for ~~deletions~~ and underlines for additions.

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
1	Enhance the Aboveground Steel Tanks Program for IP2 and IP3 to perform thickness measurements of the bottom surfaces of the condensate storage tanks, city water tank, and fire water tanks once during the first ten years of the period of extended operation. Enhance the Aboveground Steel Tanks Program for IP2 and IP3 to require trending of thickness measurements when material loss is detected.	IP2: Complete	NL-07-039 NL-13-122	A.2.1.1 A.3.1.1 B.1.1
	Implement LRA Sections, A.2.1.1, A.3.1.1 and B.1.1, as shown in NL-14-147.	IP2 & IP3: December 31, 2019	NL-14-147	A.2.1.1 A.3.1.1 B.1.1
	Implement LRA Sections, A.2.1.1 and B.1.1, as shown in NL-15-092	IP2 & IP3: December 31, 2019	NL-15-092	A.2.1.1 B.1.1
2	Enhance the Bolting Integrity Program for IP2 and IP3 to clarify that actual yield strength is used in selecting materials for low susceptibility to SCC and clarify the prohibition on use of lubricants containing MoS_2 for bolting. The Bolting Integrity Program manages loss of preload and loss of material for all external bolting.	IP2: Complete IP3: Complete	NL-07-039 NL-07-153 NL-13-122	A.2.1.2 A.3.1.2 B.1.2 Audit Items 201, 241, 270

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
3	Implement the Buried Piping and Tanks Inspection Program for IP2 and IP3 as described in LRA Section B.1.6. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M34, Buried Piping and Tanks Inspection. Include in the Buried Piping and Tanks Inspection Program described in LRA Section B.1.6 a risk assessment of in-scope buried piping and tanks that includes consideration of the impacts of buried piping or tank leakage and of conditions affecting the risk for corrosion. Classify pipe segments and tanks as having a high, medium or low impact of leakage based on the safety class, the hazard posed by fluid contained in the piping and the impact of leakage on reliable plant operation. Determine corrosion risk through consideration of piping or tank material, soil resistivity, drainage, the presence of cathodic protection and the type of coating. Establish inspection priority and frequency for periodic inspections of the in-scope piping and tanks based on the results of the risk assessment. Perform inspections using inspection techniques with demonstrated effectiveness.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121 NL-09-106 NL-09-111 NL-11-101	A.2.1.5 A.3.1.5 B.1.6 Audit Item 173
4	Enhance the Diesel Fuel Monitoring Program to include cleaning and inspection of the IP2 GT-1 gas turbine fuel oil storage tanks, IP2 and IP3 EDG fuel oil day tanks, IP2 SBO/Appendix R diesel generator fuel oil day tank, and IP3 Appendix R fuel oil storage tank and day tank once every ten years. Enhance the Diesel Fuel Monitoring Program to include quarterly sampling and analysis of the IP2 SBO/Appendix R diesel generator fuel oil day tank, IP2 security diesel fuel oil storage tank, IP2 security diesel fuel oil day tank, and IP3 Appendix R fuel oil storage tank. Particulates, water and sediment checks will be performed on the samples. Filterable solids acceptance criterion will be less than or equal to 10mg/l. Water and sediment acceptance criterion will be less than or equal to 0.05%.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121 NL-08-057	A.2.1.8 A.3.1.8 B.1.9 Audit items 128, 129, 132, 491, 492, 510

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	Enhance the Diesel Fuel Monitoring Program to include thickness measurement of the bottom of the following tanks once every ten years. IP2: EDG fuel oil storage tanks, EDG fuel oil day tanks, SBO/Appendix R diesel generator fuel oil day tank, GT-1 gas turbine fuel oil storage tanks, and diesel fire pump fuel oil storage tank; IP3: EDG fuel oil day tanks, EDG fuel oil storage tanks, Appendix R fuel oil storage tank, and diesel fire pump fuel oil storage tank. Enhance the Diesel Fuel Monitoring Program to change the analysis for water and particulates to a quarterly frequency for the following tanks. IP2: GT-1 gas turbine fuel oil storage tanks and diesel fire pump fuel oil storage tank; IP3: Appendix R fuel oil day tank and diesel fire pump fuel oil storage tank. Enhance the Diesel Fuel Monitoring Program to specify acceptance criteria for thickness measurements of the fuel oil storage tanks within the scope of the program. Enhance the Diesel Fuel Monitoring Program to direct samples be taken and include direction to remove water when detected. Revise applicable procedures to direct sampling of the onsite portable fuel oil contents prior to transferring the contents to the storage tanks. Enhance the Diesel Fuel Monitoring Program to direct the addition of chemicals including biocide when the presence of biological activity is confirmed.			
5	Enhance the External Surfaces Monitoring Program for IP2 and IP3 to include periodic inspections of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(3). Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(2).	IP2: Complete	NL-07-039 NL-13-122	A.2.1.10 A.3.1.10 B.1.11

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	Implement LRA Sections A.2.1.10, A.3.1.10 and B.1.11, as shown in NL-14-147.	IP2 & IP3: December 31, 2019	NL-14-147	A.2.1.10 A.3.1.10 B.1.11
6	Enhance the Fatigue Monitoring Program for IP2 to monitor steady state cycles and feedwater cycles or perform an evaluation to determine monitoring is not required. Review the number of allowed events and resolve discrepancies between reference documents and monitoring procedures. Enhance the Fatigue Monitoring Program for IP3 to include all the transients identified. Assure all fatigue analysis transients are included with the lowest limiting numbers. Update the number of design transients accumulated to date.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121	A.2.1.11 A.3.1.11 B.1.12, Audit Item 164
7	Enhance the Fire Protection Program to inspect external surfaces of the IP3 RCP oil collection systems for loss of material each refueling cycle. Enhance the Fire Protection Program to explicitly state that the IP2 and IP3 diesel fire pump engine sub-systems (including the fuel supply line) shall be observed while the pump is running. Acceptance criteria will be revised to verify that the diesel engine does not exhibit signs of degradation while running; such as fuel oil, lube oil, coolant, or exhaust gas leakage. Enhance the Fire Protection Program to specify that the IP2 and IP3 diesel fire pump engine carbon steel exhaust components are inspected for evidence of corrosion and cracking at least once each operating cycle. Enhance the Fire Protection Program for IP3 to visually inspect the cable spreading room, 480V switchgear room, and EDG room CO_2 fire suppression system for signs of degradation, such as corrosion and mechanical damage at least once every six months.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-15-121	A.2.1.12 A.3.1.12 B.1.13

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
8	Enhance the Fire Water Program to include inspection of IP2 and IP3 hose reels for evidence of corrosion. Acceptance criteria will be revised to verify no unacceptable signs of degradation. Enhance the Fire Water Program to replace all or test a sample of IP2 and IP3 sprinkler heads required for 10 CFR 50.48 using guidance of NFPA 25 (2002 edition), Section 5.3.1.1.1 before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner. Enhance the Fire Water Program to perform wall thickness evaluations of IP2 and IP3 fire protection piping on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion. These inspections will be performed before the end of the current operating term and at intervals thereafter during the period of extended operation. Results of the initial evaluations will be used to determine the appropriate inspection interval to ensure aging effects are identified prior to loss of intended function. Enhance the Fire Water Program to inspect the internal surface of foam based fire suppression tanks. Acceptance criteria will be enhanced to verify no significant corrosion.	IP2: Complete	NL-07-039 NL-13-122 NL-07-153 NL-08-014	A.2.1.13 A.3.1.13 B.1.14 Audit Items 105, 106
	Implement LRA Sections, A.2.1.13, A.3.1.13 and B.1.14, as shown in NL-14-147.	IP2 & IP3: December 31, 2019	NL-14-147	A.2.1.13 A.3.1.13 B.1.14
	Implement LRA Sections A.2.1.13, A.3.1.13 and B.1.14, as shown in NL-15-019	IP2 & IP3: December 31, 2019	NL-15-019	A.2.1.13 A.3.1.13 B.1.14
	Implement LRA Sections A.2.1.13, A.3.1.13 and B.1.14, as shown in NL-15-092	IP2 & IP3: December 31, 2019	NL-15-092	A.2.1.13 A.3.1.13 B.1.14

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	Implement LRA Sections A.2.1.13, A.3.1.13, and B.1.14, as shown in NL-17-052	IP2 & IP3: December 31, 2017	NL-17-052	A.2.1.13 A.3.1.13 B.1.14
9	Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to implement comparisons to wear rates identified in WCAP-12866. Include provisions to compare data to the previous performances and perform evaluations regarding change to test frequency and scope. Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to specify the acceptance criteria as outlined in WCAP-12866 or other plant-specific values based on evaluation of previous test results. Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to direct evaluation and performance of corrective actions based on tubes that exceed or are projected to exceed the acceptance criteria. Also stipulate that flux thimble tubes that cannot be inspected over the tube length and cannot be shown by analysis to be satisfactory for continued service, must be removed from service to ensure the integrity of the reactor coolant system pressure boundary.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-15-121	A.2.1.15 A.3.1.15 B.1.16

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
10	Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to include the following heat exchangers in the scope of the program. • Safety injection pump lube oil heat exchangers • RHR heat exchangers • RHR pump seal coolers • Non-regenerative heat exchangers • Charging pump seal water heat exchangers • Charging pump fluid drive coolers • Charging pump crankcase oil coolers • Spent fuel pit heat exchangers • Secondary system steam generator sample coolers • Waste gas compressor heat exchangers • SBO/Appendix R diesel jacket water heat exchanger (IP2 only) Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to perform visual inspection on heat exchangers where non-destructive examination, such as eddy current inspection, is not possible due to heat exchanger design limitations. Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to include consideration of material-environment combinations when determining sample population of heat exchangers. Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to establish minimum tube wall thickness for the new heat exchangers identified in the scope of the program. Establish acceptance criteria for heat exchangers visually inspected to include no indication of tube erosion, vibration wear, corrosion, pitting, fouling, or scaling.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121 NL-09-018	A.2.1.16 A.3.1.16 B.1.17, Audit Item 52

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
11	Deleted		NL-09-056 NL-11-101	
12	Enhance the Masonry Wall Program for IP2 and IP3 to specify that the IP1 intake structure is included in the program.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122	A.2.1.18 A.3.1.18 B.1.19
13	Enhance the Metal-Enclosed Bus Inspection Program for IP2 and IP3 to visually inspect the external surface of MEB enclosure assemblies for loss of material at least once every 10 years. The first inspection will occur prior to the period of extended operation and the acceptance criterion will be no significant loss of material. Enhance the Metal-Enclosed Bus Inspection Program to add acceptance criteria for MEB internal visual inspections to include the absence of indications of dust accumulation on the bus bar, on the insulators, and in the duct, in addition to the absence of indications of moisture intrusion into the duct. Enhance the Metal-Enclosed Bus Inspection Program for IP2 and IP3 to inspect bolted connections at least once every five years if performed visually or at least once every ten years using quantitative measurements such as thermography or contact resistance measurements. The first inspection will occur prior to the period of extended operation. The plant will process a change to applicable site procedure to remove the reference to "re-torquing" connections for phase bus maintenance and bolted connection maintenance.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121 NL-08-057 NL-13-077	A.2.1.19 A.3.1.19 B.1.20 Audit Items 124, 133, 519
14	Implement the Non-EQ Bolted Cable Connections Program for IP2 and IP3 as described in LRA Section B.1.22.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-15-121	A.2.1.21 A.3.1.21 B.1.22

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
15	Implement the Non-EQ Inaccessible Medium-Voltage Cable Program for IP2 and IP3 as described in LRA Section B.1.23. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E3, Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121 NL-11-032 NL-11-096 NL-11-101	A.2.1.22 A.3.1.22 B.1.23 Audit item 173
16	Implement the Non-EQ Instrumentation Circuits Test Review Program for IP2 and IP3 as described in LRA Section B.1.24. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E2, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121	A.2.1.23 A.3.1.23 B.1.24 Audit item 173
17	Implement the Non-EQ Insulated Cables and Connections Program for IP2 and IP3 as described in LRA Section B.1.25. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E1, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121	A.2.1.24 A.3.1.24 B.1.25 Audit item 173

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
18	Enhance the Oil Analysis Program for IP2 to sample and analyze lubricating oil used in the SBO/Appendix R diesel generator consistent with the oil analysis for other site diesel generators. Enhance the Oil Analysis Program for IP2 and IP3 to sample and analyze generator seal oil and turbine hydraulic control oil. Enhance the Oil Analysis Program for IP2 and IP3 to formalize preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria for all components included in the scope of this program. The program will specify corrective actions in the event acceptance criteria are not met. Enhance the Oil Analysis Program for IP2 and IP3 to formalize trending of preliminary oil screening results as well as data provided from independent laboratories.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-11-101 NL-15-121	A.2.1.25 A.3.1.25 B.1.26
19	Implement the One-Time Inspection Program for IP2 and IP3 as described in LRA Section B.1.27. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M32, One-Time Inspection.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121	A.2.1.26 A.3.1.26 B.1.27 Audit item 173
20	Implement the One-Time Inspection – Small Bore Piping Program for IP2 and IP3 as described in LRA Section B.1.28. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M35, One-Time Inspection of ASME Code Class I Small-Bore Piping.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121	A.2.1.27 A.3.1.27 B.1.28 Audit item 173
21	Enhance the Periodic Surveillance and Preventive Maintenance Program for IP2 and IP3 as necessary to assure that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-15-121	A.2.1.28 A.3.1.28 B.1.29

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	Implement LRA Sections A.2.1.28, A.3.1.28 and B.1.29, as shown in NL-17-052	IP2 & IP3: December 31, 2017	NL-17-052	A.2.1.28 A.3.1.28 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. Enhance the Reactor Vessel Surveillance Program for IP2 and IP3 to require that tested and untested specimens from all capsules pulled from the reactor vessel are maintained in storage.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-15-121	A.2.1.31 A.3.1.31 B.1.32
23	Implement the Selective Leaching Program for IP2 and IP3 as described in LRA Section B.1.33. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M33 Selective Leaching of Materials.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121	A.2.1.32 A.3.1.32 B.1.33 Audit item 173
24	Enhance the Steam Generator Integrity Program for IP2 and IP3 to require that the results of the condition monitoring assessment are compared to the operational assessment performed for the prior operating cycle with differences evaluated.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122	A.2.1.34 A.3.1.34 B.1.35
25	Enhance the Structures Monitoring Program to explicitly specify that the following structures are included in the program. • Appendix R diesel generator foundation (IP3) • Appendix R diesel generator fuel oil tank vault (IP3) • Appendix R diesel generator switchgear and enclosure (IP3) • city water storage tank foundation • condensate storage tanks foundation (IP3) • containment access facility and annex (IP3) • discharge canal (IP2/3) • emergency lighting poles and foundations (IP2/3) • fire pumphouse (IP2) • fire protection pumphouse (IP3) • fire water storage tank foundations (IP2/3) • gas turbine 1 fuel storage tank foundation	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121 NL-08-057 NL-13-077	A.2.1.35 A.3.1.35 B.1.36 Audit items 86, 87, 88, 417

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	• maintenance and outage building-elevated passageway (IP2) • new station security building (IP2) • nuclear service building (IP1) • primary water storage tank foundation (IP3) • refueling water storage tank foundation (IP3) • security access and office building (IP3) • service water pipe chase (IP2/3) • service water valve pit (IP3) • transformer/switchyard support structures (IP2) • waste holdup tank pits (IP2/3)		NL-14-146	
	Enhance the Structures Monitoring Program for IP2 and IP3 to clarify that in addition to structural steel and concrete, the following commodities (including their anchorages) are inspected for each structure as applicable. • cable trays and supports • concrete portion of reactor vessel supports • conduits and supports • cranes, rails and girders • equipment pads and foundations • fire proofing (pyrocrete) • HVAC duct supports • jib cranes • manholes and duct banks • manways, hatches and hatch covers • monorails • new fuel storage racks • sumps		NL-13-077	
	Enhance the Structures Monitoring Program for IP2 and IP3 to inspect inaccessible concrete areas that are exposed by excavation for any reason. IP2 and IP3 will also inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspections of elastomers (seals,			

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	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.		NL-08-127	Audit Item 360
	Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspection of normally submerged concrete portions of the intake structures at least once every 5 years. Inspect the baffling/grating partition and support platform of the IP3 intake structure at least once every 5 years.			
	Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspection of the degraded areas of the water control structure once per 3 years rather than the normal frequency of once per 5 years during the PEO.			Audit Item 358
	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 NL-11-101	

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
26	Implement the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.37. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121	A.2.1.36 A.3.1.36 B.1.37 Audit item 173
27	Implement the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.38. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M13, Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153	A.2.1.37 A.3.1.37 B.1.38 Audit item 173
28	Enhance the Water Chemistry Control – Closed Cooling Water Program to maintain water chemistry of the IP2 SBO/Appendix R diesel generator cooling system per EPRI guidelines. Enhance the Water Chemistry Control – Closed Cooling Water Program to maintain the IP2 and IP3 security generator and fire protection diesel cooling water pH and glycol within limits specified by EPRI guidelines.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-08-057	A.2.1.39 A.3.1.39 B.1.40 Audit item 509
29	Enhance the Water Chemistry Control – Primary and Secondary Program for IP2 to test sulfates monthly in the RWST with a limit of <150 ppb.	IP2: Complete	NL-07-039 NL-13-122	A.2.1.40 B.1.41
30	For aging management of the reactor vessel internals, IPEC will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-11-107	A.2.1.41 A.3.1.41

#	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: Complete IP3: Complete	NL-07-039 NL-13-122 NL-15-121	A.2.2.1.2 A.3.2.1.2 4.2.3
32	As required by 10 CFR 50.61(b)(4), IP3 will submit a plant-specific safety analysis for plate B2803-3 to the NRC three years prior to reaching the RT_{PTS} screening criterion. Alternatively, the site may choose to implement the revised PTS rule when approved.	IP3: Approximately 6 years after entering the PEO	NL-07-039 NL-07-140 NL-08-014 NL-08-127	A.3.2.1.4 4.2.5

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
33	At least 2 years prior to entering the period of extended operation, for the locations identified in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3), under the Fatigue Monitoring Program, IP2 and IP3 will implement one or more of the following: (1) Consistent with the Fatigue Monitoring Program, Detection of Aging Effects, update the fatigue usage calculations using refined fatigue analyses to determine valid CUFs less than 1.0 when accounting for the effects of reactor water environment. This includes applying the appropriate Fen factors to valid CUFs determined in accordance with one of the following: 1. For locations in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3), with existing fatigue analysis valid for the period of extended operation, use the existing CUF. 2. Additional plant-specific locations with a valid CUF may be evaluated. In particular, the pressurizer lower shell will be reviewed to ensure the surge nozzle remains the limiting component. 3. Representative CUF values from other plants, adjusted to or enveloping the IPEC plant specific external loads may be used if demonstrated applicable to IPEC. 4. An analysis using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case) may be performed to determine a valid CUF. (2) Consistent with the Fatigue Monitoring Program, Corrective Actions, repair or replace the affected locations before exceeding a CUF of 1.0.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-08-021 NL-10-082	A.2.2.2.3 A.3.2.2.3 4.3.3 Audit item 146
34	IP2 SBO / Appendix R diesel generator will be installed and operational by April 30, 2008. This committed change to the facility meets the requirements of 10 CFR 50.59(c)(1) and, therefore, a license amendment pursuant to 10 CFR 50.90 is not required.	Complete	NL-13-122 NL-07-078 NL-08-074 NL-11-101	2.1.1.3.5

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
35	Perform a one-time inspection of representative sample area of IP2 containment liner affected by the 1973 event behind the insulation, prior to entering the period of extended operation, to assure liner degradation is not occurring in this area. Perform a one-time inspection of representative sample area of the IP3 containment steel liner at the juncture with the concrete floor slab, prior to entering the period of extended operation, to assure liner degradation is not occurring in this area. Any degradation will be evaluated for updating of the containment liner analyses as needed.	IP2: Complete IP3: Complete	NL-08-127 NL-13-122 NL-11-101 NL-15-121 NL-09-018	Audit Item 27
36	Perform a one-time inspection and evaluation of a sample of potentially affected IP2 refueling cavity concrete prior to the period of extended operation. The sample will be obtained by core boring the refueling cavity wall in an area that is susceptible to exposure to borated water leakage. The inspection will include an assessment of embedded reinforcing steel. Additional core bore samples will be taken, if the leakage is not stopped, prior to the end of the first ten years of the period of extended operation. A sample of leakage fluid will be analyzed to determine the composition of the fluid. If additional core samples are taken prior to the end of the first ten years of the period of extended operation, a sample of leakage fluid will be analyzed.	IP2: Complete	NL-08-127 NL-11-101 NL-13-122 NL-09-056 NL-09-079	Audit Item 359
37	Enhance the Containment Inservice Inspection (CII-IWL) Program to include inspections of the containment using enhanced characterization of degradation (i.e., quantifying the dimensions of noted indications through the use of optical aids) during the period of extended operation. The enhancement includes obtaining critical dimensional data of degradation where possible through direct measurement or the use of scaling technologies for photographs, and the use of consistent vantage points for visual inspections.	IP2: Complete IP3: Complete	NL-08-127 NL-13-122	Audit Item 361

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
38	For Reactor Vessel Fluence, should future core loading patterns invalidate the basis for the projected values of RTpts or C_VUSE, updated calculations will be provided to the NRC.	IP2: Complete IP3: Complete	NL-08-143 NL-13-122 NL-15-121	4.2.1
39	Deleted		NL-09-079	
40	Evaluate plant specific and appropriate industry operating experience and incorporate lessons learned in establishing appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs. Documentation of the operating experience evaluated for each new program will be available on site for NRC review prior to the period of extended operation.	IP2: Complete IP3: Complete	NL-09-106 NL-13-122 NL-15-121	B.1.6 B.1.22 B.1.23 B.1.24 B.1.25 B.1.27 B.1.28 B.1.33 B.1.37 B.1.38
41	Deleted		NL-17-005	N/A

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
42	IPEC will develop a plan for each unit to address the potential for cracking of the primary to secondary pressure boundary due to PWSCC of tube-to-tubesheet welds using one of the following two options. Option 1 (Analysis) IPEC will perform an analytical evaluation of the steam generator tube-to-tubesheet welds in order to establish a technical basis for either determining that the tubesheet cladding and welds are not susceptible to PWSCC, or redefining the pressure boundary in which the tube-to-tubesheet weld is no longer included and, therefore, is not required for reactor coolant pressure boundary function. The redefinition of the reactor coolant pressure boundary must be approved by the NRC as a license amendment request. Option 2 (Inspection) IPEC will perform a one-time inspection of a representative number of tube-to-tubesheet welds in each steam generator to determine if PWSCC cracking is present. If weld cracking is identified: a. The condition will be resolved through repair or engineering evaluation to justify continued service, as appropriate, and b. An ongoing monitoring program will be established to perform routine tube-to-tubesheet weld inspections for the remaining life of the steam generators.	IP2: Complete IP3: Complete IP2: Not Applicable IP3: Not Applicable	NL-11-032 NL-11-074 NL-11-090 NL-11-096 NL-17-005	N/A

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
43	IPEC will review design basis ASME Code Class 1 fatigue evaluations to determine whether the NUREG/CR-6260 locations that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting locations for the IP2 and IP3 configurations. If more limiting locations are identified, the most limiting location will be evaluated for the effects of the reactor coolant environment on fatigue usage. IPEC will use the NUREG/CR-6909 methodology in the evaluation of the limiting locations consisting of nickel alloy, if any.	IP2: Complete IP3: Complete	NL-11-032 NL-13-122 NL-11-101 NL-15-121	4.3.3
44	IPEC will include written explanation and justification of any user intervention in future evaluations using the WESTEMS "Design CUF" module.	IP2: Complete IP3: Complete	NL-11-032 NL-11-101 NL-13-122 NL-15-121	N/A
45	IPEC will not use the NB-3600 option of the WESTEMS program in future design calculations until the issues identified during the NRC review of the program have been resolved.	IP2:Complete IP3: Complete	NL-11-032 NL-11-101 NL-13-122 NL-15-121	N/A
46	Include in the IP2 ISI Program that IPEC will perform twenty-five volumetric weld metal inspections of socket welds during each 10-year ISI interval scheduled as specified by IWB-2412 of the ASME Section XI Code during the period of extended operation. In lieu of volumetric examinations, destructive examinations may be performed, where one destructive examination may be substituted for two volumetric examinations.	IP2: Complete	NL-11-032 NL-11-074 NL-13-122	N/A
47	Deleted.		NL-14-093	N/A

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
48	Entergy will visually inspect IPEC underground piping within the scope of license renewal and subject to aging management review prior to the period of extended operation and then on a frequency of at least once every two years during the period of extended operation. This inspection frequency will be maintained unless the piping is subsequently coated in accordance with the preventive actions specified in NUREG-1801 Section XI.M41 as modified by LR-ISG-2011-03. Visual inspections will be supplemented with surface or volumetric non-destructive testing if indications of significant loss of material are observed. Consistent with revised NUREG-1801 Section XI.M41, such adverse indications will be entered into the plant corrective action program for evaluation of extent of condition and for determination of appropriate corrective actions (e.g., increased inspection frequency, repair, replacement).	IP2: Complete IP3: Complete	NL-12-174 NL-13-122 NL-15-121	N/A
49	Recalculate each of the limiting CUFs provided in section 4.3 of the LRA for the reactor vessel internals to include the reactor coolant environment effects (F_{en}) as provided in the IPEC Fatigue Monitoring Program using NUREG/CR-5704 or NUREG/CR-6909. In accordance with the corrective actions specified in the Fatigue Monitoring Program, corrective actions include further CUF re-analysis, and/or repair or replacement of the affected components prior to the CUF_{en} reaching 1.0.	IP2: Complete IP3: Complete	NL-13-052 NL-13-122 NL-15-121	A.2.2.2 A.3.2.2
50	Replace the IP2 split pins during the 2016 refueling outage (2R22).	IP2: Complete IP3: N/A	NL-13-122 NL-14-067	A.2.1.41 B.1.42
51	Enhance the Service Water Integrity Program by implementing LRA Sections A.2.1.33, A.3.1.33 and B.1.34, as shown in NL-14-147.	IP2 & IP3: December 31, 2017	NL-14-147	A.2.1.33 A.3.1.33 B.1.34
	<u>Implement LRA Sections A.2.1.33, A.3.1.33 and B.1.34, as shown in NL-16-122</u>	<u>IP2 & IP3: December 31, 2017</u>	<u>NL-16-122</u>	<u>A.2.1.33 A.3.1.33 B.1.34</u>

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	Implement LRA Sections A.2.1.33, A.3.1.33 and B.1.34, as shown in NL-17-052	IP2 & IP3: December 31, 2017	NL-17-052	A.2.1.33 A.3.1.33 B.1.34
52	Implement the Coating Integrity Program for IP2 and IP3 as described in LRA Section B.1.42, as shown in NL-15-019.	IP2 & IP3: December 31, 2024	NL-15-019	A.2.1.42 A.3.1.42 B.1.43
53	Revise Bolting Integrity Program to include visual inspection of a representative sample of closure bolting (bolt heads, nuts, and threads) from components with an internal environment of a clear gas, such as air or nitrogen. A representative sample will be 20 percent of the population (for each bolting material and environment combination) up to a maximum of 25 fasteners during each 10-year period of the period of extended operation. The inspections will be performed when the bolting is removed to the extent that the bolting threads and bolt heads are accessible for inspections that cannot be performed during visual inspection with the threaded fastener installed.	May 31, 2018	NL-17-053	A.2.1.2 A.3.1.2 B.1.2
54	Enhance the Steam Generator Integrity Program as follows. • Revise applicable procedures to specify a general visual inspection of the steam generator channel head.	December 31, 2017	NL-17-060	A.2.1.34 A.3.1.34 B.1.35
55	Revise the Buried Piping and Tanks Inspection Program for IP2 and IP3 to incorporate the changes shown in LRA Sections A.2.1.5 and A.3.1.5 in letter NL-17-084.	December 31, 2017	NL-17-084	A.2.1.5 A.3.1.5